metric: the proposal's "net benefit." The net benefit is the production-cost savings and other economic benefits associated with the proposal net of the proposal's fixed costs. This metric is expressed on an annual levelized basis that facilitates direct comparison between proposals of different sizes (in MW) and terms (number of years).

A second evaluation team was the Transmission Analysis Group (TAG), whose primary role was conducting a deliverability evaluation to indicate the feasibility and associated costs of adding a proposal to the System. The TAG also informed the EET with regards to inputs into the production cost model, such as the locations of the proposals and special unit commitment rules, i.e., "reliability-must-run" (RMR) rules. The TAG was assisted by technical experts from the Transmission Business Unit. This group was called Technical System Planning (TSP). TSP was a new aspect of the transmission evaluation and was intended to provide TAG with data and expertise that was not available to Entergy in previous RFPs due to the Federal Energy Regulatory Commission (FERC) Standards of Conduct that restricted communication with the Transmission Business Unit. FERC Order 717 relaxed these restrictions, thereby enabling increased dialogue between the RFP evaluation teams and the Transmission Business Unit.

A third evaluation team was the Viability Assessment Team (VAT). Many functions of the VAT were carried out by the EET in prior RFPs but VAT was formally-designated as a separate team in this RFP. In undertaking some former functions of the EET, the VAT expanded some areas of analysis. In particular, it addressed more directly and in more depth certain technical and commercial issues associated with the physical generation facilities of proposed resources. In essence, the VAT conducted due diligence on an on-going basis, starting from the time when proposals were submitted. The VAT was comprised of a group of subject-matter experts in the following areas: (1) Commercial; (2) Project Status/Plant & Equipment/Operations & Maintenance; (3) Environmental; and (4) Fuel Supply & Transportation. Each subject-matter expert was responsible for providing an overview and assessment of each proposal. The first analysis of VAT in Phase I was to identify any threshold deficiency that would have made a proposal non-viable (the so-called "fatal flaw" analysis). After the more detailed Phase II evaluation was underway, the VAT conducted a more thorough due diligence review in order to inform the final rankings and selections.

The fourth and final evaluation team was the Credit Evaluation Team. The Credit Evaluation Team assessed credit risk and established collateral requirements. In previous RFPs, this evaluation had not had an impact on the final bid selections. However, there is a potential for credit and collateral issues to impact the selection process, and it remained an important part of the evaluation.

The organization of the evaluation into various teams was done, in part, to conceal RFP participant identity from Entergy personnel who perform the proposal evaluation and selection so that a participant's commercially-sensitive information was shared only as necessary. The VAT and TAG required more detailed information on unit-specific issues to perform their analyses. However, this specific information was not shared in detail with the EET. To the extent possible, the EET received redacted data regarding the identity of RFP participants and the location of plants. In two instances we assented to an ESI request to approve the release of the identity of specific participants. This first instance was a release to the Entergy Operating Committee whose members wanted to begin preparations for any additions to the individual operating company resource mixes.[5] The second instance was [redacted] These two instances are discussed below.

We monitored the distribution of certain key data to ensure these processes were observed and we conclude they were observed.

2. Three-Phase Evaluation Process

The RFP evaluation proceeded in three Phases. In Phase I, the EET established a preliminary shortlist based on a preliminary cost and benefit evaluation. This shortlist included proposals whose costs and benefits indicated a reasonable expectation that the proposal could be selected in the RFP. The shortlist was also informed by the VAT's "fatal flaw" analysis and a threshold transmission analysis by TAG. All active proposals were placed on the shortlist. Hence, the

[5] The Entergy Operating Committee is the entity that administers the Entergy System Agreement among the Entergy Operating Companies. It consists of a representative of Entergy Corporation and of each of the Operating Companies.

Phase I preliminary evaluation resulted in no proposal being eliminated from further consideration.

In Phase II, EET, TAG, and VAT conducted detailed evaluations. This included updated production-cost modeling to reflect relevant information provided to EET from TAG and VAT. TAG provided costs estimates of transmission upgrade and generator interconnection, and it also provided special unit commitment (RMR) rules that were used in the production-cost modeling. The VAT provided the preliminary due diligence analysis in the form of a "Viability Ranking", which helped the EET determine its award list.

In Phase III, VAT and ESI personnel from Commercial Operations began the comprehensive due diligence and final negotiation for proposals on the award list.

3. Evaluation Models

The primary measure of a proposal's ranking was its net benefit metric, calculated by the EET. All analyses and models in the RFP evaluation process (aside from the viability assessment) essentially supported this key metric. The net benefit was calculated as the difference between estimated production-cost savings that arise from adding a proposal to the simulated Entergy System dispatch less the fixed cost of the proposal. This fixed cost mainly included the option premium (for power purchases) or the acquisition price (for asset purchases) plus transmission cost, fixed fuel transportation cost, and fixed O&M costs.

a. "Fundamental Economic Analysis"

The EET used the "Fundamental Economic Analysis" to estimate the "busbar" cost of providing electricity. The busbar cost represents the fully-allocated fixed and variable costs of producing and delivering power to the interconnection on the high-voltage system (i.e., at the busbar on the high-voltage system where Entergy takes delivery of the power, which is normally immediately down-stream of the generator step-up transformers).

The Fundamental Economic Analysis is a spreadsheet model that estimates the busbar cost using fixed and variable cost data and other proposal-specific terms and conditions. It also uses certain ESI-supplied standard assumptions such as operating profiles, fuels costs, and cost-of-capital. The Fundamental Economic Analysis model provides a dollar per-MWh "stream" of fixed and variable costs for each year of the evaluation horizon. Its main usefulness was in the net benefit calculation, described below. The net benefit calculation compared the stream of fixed costs to a separately-estimated stream of benefits, measured as annual production-cost savings plus some smaller amounts.

b. Production Cost Modeling

EET estimated production-cost savings from the production-cost modeling software commonly-known as "Prosym". The Prosym model simulates the System dispatch and estimates the total production cost of meeting load. Production cost refers only to the variable dispatch cost, which excludes all fixed costs. The production-cost savings is an estimate of System-wide production cost with the proposed resource included in the dispatch less the System-wide production cost with the proposed resource excluded from the dispatch. Notably, the Prosym model incorporates purchase opportunities from the wholesale economy energy market in addition to Entergy's current resources (owned units and current long-term PPAs).

Exit of Arkansas and Mississippi from the System Agreement. The Prosym production-cost modeling also was designed to reflect the fact that Entergy Arkansas and Entergy Mississippi have given notice of their intent to exit the Entergy System Agreement. This means these Operating Companies would no longer be committed to the System-wide joint planning and dispatch. Therefore, the production-cost modeling in the time period after the companies' announced exit from the System assumes a joint dispatch only of the remaining four companies. The modeling of the dispatch of the two exiting operating companies' was performed on a stand-alone basis. In accordance with this anticipated change, ESI estimated three sets of production-cost savings for each proposal. One estimate reflected production-cost savings assuming the proposal was to supply the remaining System. One estimate was to reflect production-cost savings assuming the proposal was to supply just Entergy Arkansas. And one estimate was to reflect production-cost savings assuming the proposal was to supply just Entergy Mississippi.

Entergy Arkansas and Entergy Mississippi are planning to exit at different points in time, but not immediately. Hence, for production cost savings estimates for initial years, the dispatch will consist of all six operating companies. In December 2013, Entergy Arkansas is intending to exit the System Agreement and in November 2015, Entergy Mississippi is intending to exit the

System Agreement. Hence, production-cost estimates will be based on the six-company dispatch for years up to and including 2013. Starting for the estimates in 2014 and continuing through the estimates for the year 2015, one set of production-cost savings will be estimated for the five-company System (by excluding Arkansas) and another set for just Arkansas alone. For the estimate of production-cost savings for the years after 2105 (i.e., for 2016 and beyond), three sets of estimates are made, one using a four-company System (which excludes Arkansas and Mississippi), one for Arkansas alone, and one for Mississippi alone. Hence, for each proposal, there will be one set of production-cost savings estimates under the assumption that the proposal is to provide capacity to today's System, one set of production-cost estimates under the assumption that the proposal is to provide capacity to Arkansas, and one set of production-cost estimates under the assumption that the proposal is to provide capacity to Mississippi. We found this approach to addressing the intended exit of Arkansas and Mississippi from the System Agreement to be reasonable.

c. Transmission Planning Model

TAG was responsible for a number of analyses that examined transmission access and cost. The primary analysis was the estimation of available transfer capacity (ATC) and any associated network upgrade costs that would be incurred to obtain the necessary transfer capacity to qualify a proposed resource as a network resource. The main model used by TAG was a transmission planning model that was comparable to the AC planning model used by TBU (for facilities studies) and by the Southwest Power Pool (for System Impact Studies). TAG also used the planning model to assess capacity commitment issues associated with out-of-merit commitment (known as reliability must-run commitments). The analysis of these capacity commitment issues was critical in estimating the results of the Prosym model for the economic evaluation. A number of other analyses were conducted by TAG, which we discuss below.

d. VAT Evaluation Models

While the VAT used a range of analyses to conduct its evaluation, no formal model was necessary. We discuss the various analyses below.

e. Summary of Models

The important details of the evaluation models are discussed in the Evaluation Section of this report (Section IV). In general, we found the proposal evaluation methodology described in the RFP to be reasonable. We did not encounter any substantive issues that required ESI to alter the basic draft of the RFP. The draft provided sufficient clarity to explain the overall process while at the same time it allowed flexibility for effective monitoring to identify and correct potential issues arising during the evaluation.

D. Draft Issuance and Participant Comments

On July 16, 2009 the Draft RFP was released to the market on the ESI RFP website. On August 8, 2009 ESI and the LPSC Staff hosted a Technical Conference at the Houston Intercontinental Airport. The main purpose of the conference was to discuss and clarify any issues relating to the draft RFP. ESI began the conference with an overview presentation. The LPSC staff also discussed a number of questions that they had previously presented in writing to ESI. Dr. Sinclair of Potomac Economics made a brief presentation on behalf of the IM. Some participants took advantage of the opportunity to submit questions in advance to ESI and some were submitted during the conference. ESI attempted to answer most questions during the conference, but some answers required additional information or further consideration. All questions and responses, both from the technical conference and otherwise, were recorded and promptly posted to the RFP website. There were 100 questions and answers posted.

After the release of the initial draft RFP in July and the Technical Conference in August, we received and reviewed comments from various parties. These included: [redacted] and the LPSC Staff. Comments were generally focused on concerns about the accuracy of the evaluation process. The main concern, which was raised in all the comments, related to the accuracy of cost estimates associated with the self-build project. The other concerns were varied, but basically related to question about how ESI was to handle specific elements of the evaluation.

1. Concerns over Self-Build Costs

All of the commenting participants raised concerns about the accuracy of the cost estimates associated with the self-build project. The basic concern is that the accuracy in the cost estimate is critical because is serves as the basis for the self-build project's ranking in the evaluation. Inaccurate cost estimates could lead to a faulty ranking and selection of a proposal that is not least cost. Because the LPSC procurement rules do not require that ESI be bound to its RFP cost estimate, the concern was that ESI (through the self-build team) may act on the incentive to underestimate costs to win the RFP and then build the project at actual costs which turn out to be higher.

We agreed that accuracy of the cost estimates is important for reliable evaluation and ranking as well as for the overall integrity of the RFP process. Some comments suggested that cost caps be used in order to place the self-build project on the same footing as the other bidders and to provide an incentive for accurate estimates. In its comments, Staff disagreed with such an approach because it could be problematic to cap project costs while following cost-of-service rules which require ESI to pass any cost savings onto customers.[6] We agree with Staff that cost caps are not appropriate as a general approach to addressing this topic. Staff has proposed to expand the scope of the independent monitoring to include review of the self-build costs. We agreed that this approach would address the concerns raised by the comments. ESI cooperated with us and the LPSC Staff to arrange an expansion of the IM scope to address self-build cost monitoring. This is discussed in more detail below.

2. Other Evaluation Issues Raised in Participant Comments

There were eight other evaluation issues raised in the Participant Comments. These eight specific issues are addressed here in no particular order.

One issue involved the consideration of additional potential transmission projects that could increase a proposal's production-cost benefits (including production-cost benefits arising from a proposal's ability to satisfy "RMR" rules). We agreed there could be a significant benefit from allowing such additional transmission projects to be considered in conjunction with the proposal, and bidders could specify such projects in the "Special Considerations" section of the RFP submission form. We recognized that conducting such supplemental transmission studies would

6 LPSC Staff has taken the position that cost caps are best considered on a case-by-case basis rather than as a blanket rule in the RFP itself.

require additional time and resources and may not be feasible within the RFP process. However, ESI agreed, in consultation with the IM, to consider such options in the transmission evaluation.

A second issue involved the accounting of economic benefits associated with a unit's location. We confirmed that ESI accounted for such benefits through the production-cost modeling and the RMR benefits assessment.

A third issue involved reflecting the emission allowance costs in the economic evaluation. We confirmed that ESI represented these costs, and we monitored the methods to ensure reasonable treatment of such costs.

A fourth issue related to explicitly valuing a generator's Automatic Generation Control (AGC). The Staff proposed imputing the cost of installing AGC to proposed units that do not have it presently installed. We concluded Staff's proposal was reasonable, and ESI agreed to conduct such an analysis. As it turned out, all units proposed had AGC installed except the one unit offering the low-heat rate call option proposal, which is a product dispatchable in blocks and is not intended to follow load.

A fifth issue raised questions about what transmission model would be used in the deliverability evaluation. ESI confirmed that the model will include all transmission upgrades in the approved Construction Plan, which we found reasonable.

A sixth issue involved concerns about non-discriminatory application of the de-listing process. We confirmed that ESI's application of the delisting process was non-discriminatory. We describe our monitoring of the delisting process below.

A seventh issue involved concerns that a proposal should not be rejected based on location when transmission capacity may be available to transmit power to where Entergy needs it. We confirmed that ESI did not eliminate proposals solely on location.

Finally, the eighth issue was a comment concerning the collateral requirement, which was clarified in ESI's reply comments submitted October 8, 2009.

Overall, we found ESI's response to participant comments to be reasonable.

E. RFP Administrator

The draft RFP provided contact information for the RFP Administrator and invited market participants to submit questions in writing to this person. IM contact information was also provided. Nearly all inquiries by market participants were directed to the RFP Administrator. These were both in the form of phone calls and email. We worked closely and effectively with the RFP Administrator in monitoring the communications from RFP participants. It is not practical to monitor all participant communications. Many inquiries received by the RFP Administrator related to matters that would burden any monitoring system were they all to be brought to the IM's attention. Many issues involved simple questions about interfacing with the RFP submission software or questions that could be addressed by reference to the RFP document. Accordingly, effective monitoring of the communications to the RFP Administrator required judgment on the part of the RFP Administrator regarding what issues to present to the IM. This judgment involved primarily issues raised over the telephone because, in general, email communication was copied to the IM. Telephone inquires also resulted in an email to the IM based on the judgment of the RFP Administrator. We found that the RFP Administrator exercised good judgment in making issues known to us. We also found the RFP Administrator employed effective organizational skills, which facilitated the overall RFP process.

III. PROPOSAL SOLICITATION AND RECEIPT

With the input received from potential RFP participants, the LPSC staff, and the IM, ESI issued the final RFP on September 24, 2009. This was three weeks prior to the start of the proposal submission period.

A. RFP participant Registration and Proposal Submission

ESI used its web-based system for registration and proposal submission. This system was introduced in the 2008 summer RFP, which was ultimately suspended. It replaced the former process, which involved paper forms and Excel spreadsheets. We conclude that the new system was a significant improvement over the old process, and made the RFP process easier for ESI staff, the RFP participants, and the IM.

The RFP participant registration and proposal submission process consisted of three separate steps.

1) RFP participant registration (November 2, 2009 to November 5, 2009). Using the web-based system, the RFP participants provided company contact information and identified the units and proposals they were choosing to offer. During this step, identification numbers for each RFP participant, unit, and proposal were created. These were used throughout the process to allow anonymous identification.

2) Submittal Fee (due November 12, 2009). RFP participants were required to pay $5000 per each proposal submitted. Payment of this fee was required prior to the web-based interface software being able to accept Proposal Submission in Step 3.

3) Proposal Submission (November 16, 2009 to November 19, 2009). RFP participants entered the detailed data for each of their proposals into the web-based interface.

There were 24 proposals received and all of them were considered to be conforming. This meant they met the minimum terms of the product for which the proposal was offered. One of the 24 proposals was received two days late. This was because the proposal was issued in hard copy and was received two days later by express delivery. We were made aware that a clerical error caused the late proposal, and so we recommended it be submitted into RFP. ESI accepted this recommendation.

Aside from this one delayed submission, there were no significant issues arising in the registration and proposal submission process. Although ESI conducted dry-run test simulations, minor technical issues arose during actual operation of the automated RFP submission interface. However, because of controls and backup systems, these technical issues were identified and rectified. None of the technical issues resulted in adverse impacts to the RFP process. Moreover, the interface improved the handling and processing of registration and proposal submissions.

B. Redaction of Proposals

Proposals were due on November 16, 2009. In preparation, a Potomac Economic representative traveled to Houston to monitor the processing of the proposals. The main process issues involved transferring the proposal data to reports for the different evaluation teams. This is an area where the new electronic system provided significant benefit. The system produced a customized report for each team that contained only the data fields needed by the given team. Each report still required individual handling, however. The RFP Administrator and Potomac Economics worked to redact the reports to ensure there was no information in the report that was not needed by the particular team and to ensure there was no information that identified the RFP participant or the resource. There were a number of proposals that contained lengthy "special consideration" sections that required considerable redacting.

After the redaction process, the evaluation teams received a redacted version of the proposal data as well as any redacted additional data that the RFP participant may have submitted separately in conjunction with their proposal. Unredacted versions of all data were provided to the RFP Administrator, the IM, and the ESI legal team. No evaluation team member had access to the unredacted versions of reports. A system administrator verified that only evaluation team members could access redacted files through the restricted file share location.

C. Executive Report and Release of Bidder Identities

On December 3, 2009 we submitted the Executive Report to the operating committee as required by Section 4.1.1 of Appendix G to the RFP:

> Upon completion of the Proposal Submission Process, the IM will prepare an Executive Report which will communicate the following: (1) the actual number of Bidders submitting proposals; (2) the total number of resources for which proposals have been submitted; (3) the number of proposals submitted for each product category; and (4) any additional information that such executives may request and

that the IM concurs is appropriate to provide. The Executive Report will be communicated only to the Entergy Operating Committee and to the Group President of Utility Operations and, upon request and with the concurrence of the IM, to other senior executives.

Pursuant to the IM discretion under item (4) of the Section, Entergy requested that the report include the identity of the individual resources. We concurred with the request based on Entergy's explanation that the RFP process would benefit from the operating committee members having time to prepare for possible selections. Knowledge of the resources offered allowed this preparation to commence.

D. Summary of Proposals

All 24 proposals were deemed to be conforming to the minimum conditions of the RFP and, therefore, all advanced to the Phase I evaluation. The 24 proposals were from a total of twelve different bidders and were based on sixteen different resources. Table 2 provides a summary of the offers.

Table 2: Summary of Proposals Offered

Product	Number of Proposals	Total MW from Proposals	Developmental Proposals
A - Baseload Purchase Agreement	1	185	0
B - Tolling Purchase Agreement - Load-Following CCGT	12	5,532	4
C - Low Heat Rate Call Option	2	539	0
D - Dispatchable Purchased Agreement - Peaking CT	0	0	0
E - Ownership Acquisition	9	5,827	2
Total	24	12,083	6

Table 2 shows that the 24 proposals offered a total of over 12,000 MW of capacity. Some proposals, however, were variations on the same resource. Excluding these proposals that were mutually exclusive, a total of 8,310 MW was offered. Six developmental proposals were offered for the Amite South capacity need (in accordance with the RFP, no development projects were considered for the System-wide need). All existing resources offered were CCGT units. Hence, in accordance with the RFP, these units were to be evaluated for both the System-wide need and the Amite South need.

E. Acadia Power Partners Transaction [redacted]

Prior to the issuance of the RFP, ESI entered into negotiations and concluded an agreement on behalf of Entergy Louisiana LLC (ELL) to purchase Power Block 2 of the Acadia Facility owned by Acadia Power Partners (APP). At the time the RFP proposals were received, an application for certification of the proposed Acadia transaction was pending before the LPSC. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

IV. Proposal Evaluation – Phase I

The proposal evaluation process was conducted in three main processes, which occurred in parallel fashion and advanced through three phases. Phases I and II required most of our monitoring work and produced an award list. While Phase III was important, it involved substantially less opportunity for unfair or subjective actions that could have affected the final selection, and accordingly required considerably less monitoring.

EET was responsible for the main evaluation in both Phase I and Phase II in accordance with the Economic Evaluation Process (Appendix E-1 of the RFP). The economic evaluation process assessed the economic cost and benefits of each proposal to identify a net benefit metric. A preliminary net benefit calculation was used in Phase I to establish a preliminary shortlist. A detailed net benefit evaluation was used in Phase II to establish the award list. In both Phase I and Phase II, EET incorporated analyses and conclusions produced by the TAG and VAT. TAG's transmission evaluation estimated various transmission costs and benefits associated with each proposal and, as indicated above, the evaluation was used to inform the Economic Evaluation Process. The VAT was responsible for the viability assessment. In this assessment, the VAT evaluated certain technical aspects of the proposals with respect to environmental, fuel supply, and commercial matters and reported this to the Economic Evaluation Team in order to inform the proposal evaluation and rankings. A fourth evaluation processes is a credit evaluation process conducted by the Credit Evaluation Team to identify credit and collateral in order to identify ESI's requirement for credit protection. The credit evaluation could impact the selection process after the award list is established. It does not directly affect the proposal rankings in Phase I or Phase II.

In this Section, we discuss the Phase I evaluation. In Section I, we discuss the Phase II evaluation, and in Section I, we discuss Phase III.

A. Net Benefit Analysis

The EET net benefit analysis is the main result of Phase I. It is a comparison of each proposal's costs and benefits to the Entergy System (the estimated production costs savings net of the proposal estimated fixed costs). The net benefit analysis is conducted using two models. First is what ESI terms the Fundamental Economic Analysis, which is a cost model that estimates various fixed costs of each proposal based on the proposal's specific offer parameters as well as certain ESI assumptions. The second analysis is the production cost simulation, which uses the as-bid technical aspects and cost of each proposal to estimate the System-wide production-cost savings from adding the proposal to the Entergy production mix.

a. Fundamental Economic Model

The Fundamental Economic Model uses inputs and assumptions taken directly from the bidder's proposal (e.g., option premium, heat rate, start date, stop date, VOM cost, etc.) and from ESI inputs and assumptions (e.g., availability, term of the RFP). The proposal inputs and assumptions and ESI inputs and assumptions are used together to develop the annual fixed costs associated with each proposal over the term of the RFP. It also produces annual variable costs.[9] For PPAs fixed costs reflect the offered option premium and any fixed fuel transportation costs. For acquisitions, fixed costs include fixed O&M and annual capital cost recovery expenses (return on and amortization of net plant plus other plant expenses like taxes and insurance).

The Fundamental Economic Model also incorporates annual fixed cost pursuant to capital investments in transmission assets required to integrate the proposed resources (i.e., to obtain network service). However, in Phase I, these costs are not included. They are included in Phase II and we discuss them below in our presentation of Phase II analysis and results.

Over the time period of any given proposal, the annual fixed cost may vary. Similarly, as we discuss below, the annual production-cost savings may vary. In order to use the annual estimates of fixed costs, the model calculates an annual total cost and, using the ESI-provided discount rate, calculates a levelized annual cost based on the net present value of the stream of annual costs. The cost estimates are then converted to $/MWh based on the bid capacity and ESI-assumed capacity factors.

Fixed costs reflect the option premium or acquisition price as well as smaller fixed items such as Fixed O&M, if any. Variable costs reflect fuel, variable O&M, emission adders, and start-up costs. Each proposal is assumed to operate in hours that are based on the type of product offered.

9 These estimated variable costs are not used in the net benefit estimates and so are not discussed further.

Supplemental Capacity. The analysis also includes benefits from any supplemental capacity associated with combined-cycle units. This benefit (which is shown as a negative cost) is based on the ESI estimate of market-based prices for capacity. The estimated capacity price is then applied to the amount of supplemental capacity for each proposal. This capacity price is estimated from actual purchase data. In particular, recent market purchases of power are compared to the estimated running cost of resources supporting such purchases. In this manner, the price of the capacity component of a particular resource will depend on its heat rate. We find this to be a reasonable method of estimating market capacity prices for evaluation purposes.

We evaluated the Fundamental Economic Analysis and found the framework to be reasonable and followed the economic evaluation description in the RFP.

b. Production-Cost Savings

Production-Cost Savings Estimate. Production-cost savings were estimated using Prosym. Prosym simulates the commitment and dispatch of utility generation resources and estimates the production cost of meeting hourly load given generator characteristics, fuel costs, and transmission constraints. Prosym is a common and well-accepted method for measuring the production-cost impact of generator dispatch and other System constraints. The evaluation team estimated the production-cost saving for an individual proposal by first estimating the total annual production cost of meeting load in a "base case", which reflects Entergy's existing resources and assumptions regarding purchase opportunities in the regional economy energy market. Next, the proposed resource was included in the Entergy dispatch for each year for which it was offered, and the total annual production cost was estimated and then compared to the base case production costs to estimate the annual production-cost savings, if any.

We reviewed the assumptions used in the Prosym model and found no systematic bias. One area that we judged to be important and requiring further inquiry was the modeling of the economy energy market. It is important because of its potential effects on the economic evaluation results. The production cost model determines a certain level of economy purchases by the Entergy System. If the economy energy price is assumed too low, then the modeled System will rely more heavily on economy energy purchases and rely less on the proposed resources, resulting in lower production-cost savings for the proposed resources. If the economy energy price is too high, the opposite is true, making production-cost savings estimates too high.

ESI models the economy energy market in the Prosym model based on hourly clearing prices provided by Ventyx advisors (provider of Prosym). ESI used the Ventyx semi-annual Power Reference Case for the Southeast Region for years 2008-2033. It contains estimates of hourly prices for each hour of each year. The Ventyx values are based on various natural-gas and emissions price scenarios, which ESI adjusts to reflect its own natural-gas price and emissions price point of views. These hourly prices then serve as a basis of block energy pricing. We find this modeling construct to reasonably reflect the supply and pricing likely to be available in the economy energy market. Given that the basis of the estimates is provided by a third-party commercial enterprise, our concerns are eased further.

This approach to economy energy market modeling is different than in previous RFPs. Previously, EET developed economy energy assumptions using a simulation of regional market based on a model called MIDAS. The change to a third-party provider of energy market prices was due to decisions by ESI concerning tools used for internal analysis of markets. According to the company, when its license for the MIDAS model was expiring, it reviewed its internal needs and determined that ESI could obtain comparable functionality more efficiently by allowing the MIDAS license to expire, and using the Ventyx Power Reference Case to provide similar information.

c. Transmission Inputs to the Phase I Evaluation

The Phase I evaluation does not include any transmission upgrade costs or interconnection costs. Instead, because Prosym is modeled as a collection of small sub regions, not as individual transmission nodes as in a transmission planning model, TAG provided EET the Prosym sub region information for each proposal, but not the exact network bus information. This helped conceal the identity of the proposal from the evaluation team, in accordance with the terms of the RFP.

d. Viability Assessment ("Fatal Flaw" Analysis)

For Phase II, VAT conducted a "Threshold Viability Assessment" referred to as a "fatal flaw" analysis. This analysis was based on the review of the responses to a detailed questionnaire (Appendix H of the RFP) which concerned specific data and information about each proposal. The VAT sought to determine whether any key aspect of a proposal was such that the proposal was not viable. Primarily, the analysis focused on whether resources could satisfy the Commercial Operation Date based on the questionnaire. The VAT determined that no proposal had any such fatal flaw.

e. Phase I Results (Preliminary Short Lists)

Table 3 summarizes the results of the Phase I net benefit analysis.

Table 3: Phase I Net Benefits – System

Proposal	Plant Name	Region	Proposal Type	MW	Fixed Exp. (/kW-yr)	Imputed Debt (/kW-yr)	Production Cost Savings (/kW-yr)	Other Benefits (/kW-yr)	Net Benefit (/kW-yr)
[redacted]									

The Table shows the costs and benefits to the Entergy System. Recall that this is based on a production cost model that envisions Entergy-Arkansas and Entergy-Mississippi departing the System by 2014 and 2016, respectively. Net benefit estimates for resources serving only the

Entergy-Arkansas and Entergy-Mississippi operating companies are discussed below. We first discuss Table 3 because the methods used to arrive at these results were used also for the results concerning Arkansas and Mississippi delivery.

Levelized values. As noted in Table 3, the per-kW-yr values are presented in levelized annual amounts. A levelized value is the constant value (cost or benefit) that, if it were incurred in each period of the proposal, the stream of values would produce a present value equivalent to the present value of the actual projected values. We find this presentation to be an effective way of comparing proposals that may provide streams of benefits of differing lengths or streams of benefits that may start and stop at different times.

Proposal Costs. The Table shows two types of proposal cost categories, shown in columns titled "Levelized Fixed Expenses" and "Imputed Debt". The values given by "Levelized Fixed Expenses" are the levelized fixed cost produced by the Fundamental Economic Model, discussed above. For a PPA, the bulk of fixed costs arise from the annual option premium, but it also includes fixed O&M and fixed fuel delivery costs. For unit acquisitions, the primary fixed costs are annual capital cost recovery expenses (return on and amortization of net plant plus other fixed plant expenses like taxes and insurance). Fixed costs for acquisitions also include fixed O&M and fixed fuel delivery expenses.

The column titled "Imputed Debt" reflects ESI's calculation of the incremental finance cost to Entergy from entering a purchase power agreement. Accordingly, this cost only applies to PPAs. The credit agencies grade corporate debt like Entergy's based on a range of financial indicators, the company's debt, and other obligations. According to ESI commercial operations, a PPA is considered to be a debt at 25 percent of the PPA fixed payment obligation. Hence, if Entergy secures a PPA as part of this RFP, the total debt possessed by the company for purposes of a credit rating metrics will increase. Because a credit rating will decline when the debt ratio increases (all else equal), initiating a PPA might decrease Entergy's credit rating and, consequently, increase its cost of capital. In order to reflect this in the RFP evaluation, ESI undertakes an analysis to impute these additional costs. ESI calls this analysis the Imputed Debt analysis. The Imputed Debt analysis estimates the capital costs associated with Entergy adding equity in order to maintain the same credit rating agency-determined capital structure.

The analysis is provided by the formula:

Imputed Debt Costs = (*NPV of PPA Capacity Charges*) x (*Portion Treated as Debt*) x

(1-*Debt-to-Equity Ratio*) x (*Pre-tax Cost of Equity – Cost of Debt*).

We find the estimates of imputed debt to be based on reasonable assumptions and methods. Given that all proposals were included on the shortlist, including imputed debt costs did not adversely affect any proposal's evaluation in Phase I.

Proposal Benefits. Proposal benefits are represented by the columns titled "Production-cost savings" and "Other Proposal Benefits". As the Table shows, production-cost savings provide the bulk the proposal benefits. Production-cost savings are the System production-cost savings estimated in the Prosym production cost modeling discussed above. The category Other Proposal Benefits consists of three estimated benefits: pre-delivery benefits, post-delivery benefits, and supplemental capacity benefits. *Supplemental capacity benefits* are part of the fundamental economic analysis and were explained above. They are benefits from any supplemental capacity associated with combined-cycle units and is based on the ESI estimate of market-based prices for capacity. As discussed above, we find the estimate of this benefit to be reasonable. *Pre-delivery and post-delivery benefits* arise due to the normalizing procedures used in the evaluation. If the proposed start and end dates of a resource did not correspond to product specifications set forth in the RFP, the evaluation team added the net benefit of short-term purchases to the periods of the product specification not covered by the proposal. Hence, if a proposal was offered to begin after the product-specific start date, the evaluators assumed that short-term purchased power would be required until the time when proposal is available to the System. Likewise, for proposals that did not offer terms up to the product-specific end date, the evaluators assumed purchases would be necessary in those years when the resource was no longer available.

Results. Net benefits are calculated as the sum of the benefits and the costs. As Table 3 shows, net benefits from the Phase I evaluation for the System range from a high value of [redacted] to a low value of [redacted]

Amite South. The Phase I evaluation did not evaluate proposals specifically for Amite South delivery.

Entergy Arkansas and Entergy Mississippi. As discussed above, the economic evaluation was conducted under the base case assumption that Entergy Arkansas and Entergy Mississippi would follow through on their plans to exit the System Agreement. Hence, for Entergy Arkansas and Entergy Mississippi, separate net benefit analyses are necessary in order to measure the potential benefit of choosing a resource allocated to one of those two companies. However, the Phase I analysis for these individual Systems was not used to eliminate any proposal.

Table 4 below shows the net benefit results for Entergy Arkansas and Entergy Mississippi. For both the Arkansas and Mississippi analysis, resources located in Amite South were not considered.

Table 4: Phase I Net Benefits – Entergy Arkansas

Proposal	Plant Name	Region	Proposal Type	MW	Fixed Exp. (/kW-yr)	Imputed Debt (/kW-yr)	Production Cost Savings (/kW-yr)	Other Benefits (/kW-yr)	Net Benefit (/kW-yr)
[redacted]									

[redacted]

Table 5: Phase I Net Benefits – Entergy Mississippi

Proposal	Plant Name	Region	Proposal Type	MW	Fixed Exp. (/kW-yr)	Imputed Debt (/kW-yr)	Production Cost Savings (/kW-yr)	Other Benefits (/kW-yr)	Net Benefit (/kW-yr)
[redacted]									

f. Phase I Conclusions

We found the models used in the Phase I evaluation to be reasonable and found the estimates to be accurate and a good basis for establishing the Phase I shortlist.

g. Post-Phase I Events [redacted]

[redacted] *PPA Eliminated.* [redacted] submitted two proposals into the RFP from the same resource – an acquisition and a PPA. In May 2010, ESI eliminated the PPA proposal. This was the result of some extended exchanges between ESI and [redacted] concerning special considerations that [redacted] ncluded in its proposal. These special considerations sought to modify the capacity availability requirements for the PPA. In particular, [redacted] sought to replace fixed availability requirements with a proposal to provide the availability within a bandwidth. It also sought to delay establishing the dependable capacity to the beginning of each season instead of guaranteeing it. [redacted] also offered a mechanism to reduce capacity payments in relation to decreases in unit efficiency, although this mechanism was not made clear.

While we agreed with ESI that the [redacted] considerations were material changes to the product package terms, we were open to considering [redacted] rationale for them. However, after several exchanges between ESI and [redacted], we did not find sufficient justification to recommend that the special considerations be accepted. Accordingly, we found ESI's elimination of the PPA proposal as nonconforming to be reasonable.

[redacted] *Expanded.* Initially [redacted] offered two PPAs into the RFP from the [redacted] facility. These proposals were each offers at [redacted] MW. At the end of Phase I, [redacted] requested retaining the existing proposals but allowing a third proposal that would be offered a [redacted] MW from the same facility. We agreed with ESI's decision to accept this modification.

B. Self-Build Cost Monitoring

As discussed above, all participants offering comments on the RFP evaluation (including the LPSC Staff) raised concerns about the accuracy of the cost estimates associated with the self-build project. Because we agreed there was an incentive for ESI (through the Self-Build Team) to underestimate costs, we supported the LPSC Staff proposal to expand the scope of the independent monitoring to include review of the self-build costs. ESI cooperated with us in arranging for this change.

The extension of the IM Scope was to monitor the self-build costs with the intent of determining the reasonableness of the costs. This monitoring was not intended to be a separate cost estimate. Therefore, our objectives in this area were to examine the main cost areas and evaluate whether these cost areas were within reasonable ranges, and to determine whether any major cost items may have been omitted. We evaluated individual cost items only when we judged the Self-Build Team's estimate to be significantly lower than or significantly higher than reasonable benchmarks. In conjunction with ESI, we retained the consulting firm Industry and Energy Associates (IEA)[10] to assist in establishing reasonable benchmarks for the major cost areas. IEA is an engineering consulting firm with electric power industry experience in project management, procurement, and construction management, including considerable experience in combined cycle construction projects.

The cost areas developed by the Self-Build Team were the basis of the IEA analysis. However, we reiterate that IEA was asked to identify any omitted cost areas. There are a variety of ways to organize the cost categories of the self-build project. The Self-Build Team identified three main cost areas. The largest cost area was direct costs, which included the main engineering, procurement, and construction contract costs ("EPC costs"). [redacted] The second largest category of costs was Allowance for Funds Used During Construction (AFUDC). This is a standard utility accounting concept and represents the carrying cost of capital incurred during the time the project is being built but before it is placed in service. Entergy is able to recover these carrying costs in regulated rates and, hence, are properly included in the project cost for evaluation purposes. AFUDC costs are abou[redacted] of the total project costs. The final cost category, which has relatively minor contribution to the final cost[redacted] was the indirect loaders. As used by the Self-Build Team, this is a forecast of the indirect cost of labor, such as benefits and taxes, and an allocation of ESI overhead.

In accordance with the RFP, the Self-Build Team submitted a proposal along with all other proposals in November 2009. The underlying cost estimates for this proposal were provided to us and we conveyed these to IEA in order to begin the evaluation. IEA provided a first draft report in February 2010.

[10] In the course of our engagement with IEA, the firm was acquired by Stantec.

Table 6 shows the comparison of the self-build cost as submitted in the RFP to the benchmarks developed by IEA in its report. The comparison is organized in accordance with the three main cost categories discussed above. The Table illustrated what was discussed above: [redacted].

Table 6: Comparison of Initial Self-Build Cost Estimates to IEA Benchmarks

	Self-Build Team Initial Offer	IEA Benchmarks	Delta
	(1)	(2)	(1)-(2)
[redacted]			

As the bottom line on Table 6 shows, the Self-Build Team estimate of total project costs was above the IEA benchmark estimates – the total project cost estimated by ESI was [redacted], versus [redacted] for the IEA estimate. In general, the higher estimate by the Self-Build Team eases concerns that the Self-Build Team may have underestimated the project costs. Hence, we found the initial self-build cost estimates to be reasonable and would result in a fair evaluation of the self-build project relative to the other proposals in the RFP.

While the total project cost comparison provides a good basis for judging the reasonableness of the Self-Build Team estimates, we identified some individual cost items within the EPC sub-category where there was a significant divergence between the Self-Build Team estimates and the IEA benchmarks. Table 6 shows a number of individual items under the Direct Cost category associated with the EPC contract. These are the items that individually diverged from the IEA estimates by more than [redacted]. As shown in column (3), the total of the Self-Build Team EPC contract cost estimates was [redacted] than the estimated IEA EPC costs.

In many of the non-EPC Direct Cost categories, IEA used the same values as the Self-Build Team. These were largely instances when IEA agreed that the Self-Build Team approach was reasonable and IEA did not provide a benchmark. In other instances, the specific cost estimation methods used by the Self-Build Team may not have been one with which IEA had prior experience. This is not surprising because not all elements of cost estimating are standardized. In such cases, the Self-Build Team values were accepted in the draft report until IEA could ascertain more information about the methods used. These cases arose in relatively minor cost categories and, as explained next, attempts were made to reconcile areas where there was a lack of clarity.

For instances of relatively large discrepancies between the Self-Build Team and IEA, an attempt was made to reconcile the estimates. The results above were based on the first draft of the IEA analysis that did not have the benefit of direct discussion with the Self-Build Team. Following this first draft report, we coordinated and monitored a teleconference with the Self-Build Team and IEA to address some of the larger cost divergences. This was a productive process and IEA endeavored to revise its analysis. The teleconference coincided closely in time with the Self-Build Team's submission of a "best-and-final" offer in April 2010. Accordingly, IEA provided a revised analysis in May 2010 that accounted for the best-and-final offer and reconciled certain cost items based on the discussions with the Self-Build Team.

Table 7 shows a comparison of costs based on IEA's revised analysis and the Self-Build Team's best-and-final offer.

Table 7: Comparison of Best-and-Final Self-Build Cost Estimates to IEA Benchmarks

	Self-Build Team Best and Final	IEA Benchmarks	Delta
	(1)	(2)	(1)-(2)
[redacted]			

As the bottom line in the Table indicates, the Self-Build Team costs under the best-and-final offer are very close to the revised IEA benchmarks. This is not surprising, given that the best-and-final offers should reflect a more informed proposal by the Self-Build Team and that the discussions between IEA and the Self-Build Team would have helped IEA understand better the various cost components and facilitate the development of more refined benchmarks.

A comparison of Table 6 and Table 7 shows that the total cost between the initial Self-Build Team cost estimate and the best-and-final cost estimate declined by [redacted], which is a [redacted] Table 8 shows a comparison of the Self-Build Team cost estimates between the initial estimate and the best-and-final estimate to show the source of the differences.

Table 8: Comparison of the Self-Build Team Initial and Best-and-Final Estimates

	Self Build Team Initial (1)	Self Build Team Best and Final (2)	Delta (1)-(2)
[redacted]			

As shown in the Table, the two categories that reflect the largest cost decreases between the Self-Build Team's November proposed costs and the best-and-final costs are Total EPC costs and AFUDC costs. [redacted]

[redacted] With regard to the AFUDC amounts, [redacted], which directly affects the accumulated financing costs during the construction phase. Overall, based on our review of the Self-Build Team cost estimates and the IEA benchmarks, we concluded that the self-build cost estimates were reasonable and would result in an unbiased evaluation of the proposal.

V. Proposal Evaluation – Phase II

Phase II was the main phase of the evaluation process and resulted in the award list. The award list resources moved to comprehensive due diligence and negotiation in Phase III. To arrive at the award list, three evaluations were conducted: (1) The Phase II net benefits analysis, (2) the VAT Viability Assessment; and (3) the "portfolio" analysis.

The Phase II net benefit analysis was similar to the Phase I net benefit analysis but included the transmission costs and refinements to the production cost model. Recall that in Phase I, a preliminary production cost model was used to estimate production-cost savings and transmission costs were not considered. These Phase II refinements included updated information from subject matter experts (e.g., fuel costs), best-and-final offers from bidders, and preliminary due diligence by VAT and TAG.

The second evaluation result was the viability ranking provided by VAT. This ranking is an extension of the threshold viability analysis from Phase I (the "fatal flaw" analysis), which sought to identify qualitative aspects of each proposal to determine its ability to meet the key requirements of the RFP product, primarily in-service dates. In Phase II, the viability assessment extended to other key proposal terms with the objective of assigning quantitative scores in accordance with the proposal's viability to supply the offered product.

The third evaluation is the portfolio evaluation. In this evaluation, TAG and EET evaluated portfolios of proposals to determine production-cost benefits, availability of simultaneous delivery, and to identify any other transmission issues related to portfolio delivery.

This Section is divided in three main subsections, corresponding to the main Phase II evaluation results. In subsection A, we address the net benefit analysis, including the Amite South evaluation. In subsection B, we discuss the VAT viability analysis. Finally, in subsection C, we address the results of the portfolio evaluation and the award list.

A. Net Benefit Analysis

In Phase II, EET finalized the net benefit analysis by (1) incorporating transmission costs; (2) refining the production cost modeling to reflect updated information (including best-and-final offers); (3) providing Amite South-specific delivery evaluation, and (4) conducting the Acadia sensitivity. These evaluations are discussed below.

1. Transmission Evaluation

The transmission evaluation conducted by TAG to support the net benefit estimates included three main analyses. First, TAG estimated the transmission costs to qualify a proposed resource as a network resource. This mainly reflected transmission network upgrade costs, if any, but other costs as well. For new resources, this also included generation interconnection costs.[11] The transmission cost estimates were used directly in the net benefit analysis. The second main analysis was the study of reliability-related unit commitments (commonly known as reliability-must-run, or "RMR" units). This study determined if a proposed resource could substitute for other existing System units that are committed and operated as reliability RMR units. This information was used in the production cost modeling by EET to assess the RMR-related production-cost benefits of proposals. Any transmission upgrade costs identified to allow a resource to substitute for an existing RMR unit for this purpose were used directly in the net benefit analysis. The third main analysis was the Amite South ("AMS") evaluation. This evaluation identified the transmission network upgrade measures required to make a CCGT unit located outside AMS deliverable into AMS (including into the DSG sub-region of AMS). This analysis also identified any incremental transmission upgrade costs identified as necessary in the AMS Interface Test to restore the transfer limits across AMS to the level that would prevail without the proposed resource.

In addition to these three main analyses, TAG also provided additional analyses to inform the EET of certain other analysis, such as real-time location-specific congestion costs and line losses.

[11] Bidders offering new developmental resources were instructed in the RFP to exclude interconnection costs from their proposals. The bidders would still have been responsible for paying these costs, and ESI intended to address the appropriate compensation to the bidder for those costs in the negotiation phase of the RFP based on the actual interconnection costs in the generator interconnection facilities study and other appropriate considerations. This approach was taken, in part, to alleviate the uncertainty in these costs that exists at the time of proposal submission. ESI used a consistent method of estimating the interconnection costs for all new resources in the evaluation process.

a. Network Resources Transmission Costs

In order for ESI to procure a firm resource to serve Entergy native load, it must designate the resources as a "network resource" and secure firm transmission service. In some cases, the existing and planned transmission network may be sufficient to fully integrate the resource. In other cases, physical transmission upgrades or "delisting" of existing resources (or both) must be made to ensure firm deliverability.

The network resource evaluation is essentially an evaluation to determine whether there is sufficient available transmission capacity (ATC) to integrate the proposed resource into the Entergy System. TAG estimated the ATC using methods that would be applied by the Entergy Independent Coordinator of Transmission (the ICT) when assessing a request for network integration transmission service under the Entergy Open Access Transmission Tariff.

TAG used seasonal power flow cases that reflected the current transmission assets plus future projects that were included in the approved Construction Plan. This is a reasonable approach as it includes only facilities that are reasonably assured of being part of the network in the future. For each proposal, TAG determined whether existing and planned transmission capacity was sufficient to qualify the proposal as a network resource. This means the proposal must be deliverable during the peak hour of each year of the planning horizon. The planning horizon in the TAG evaluation extended to 2018. After 2018, transmission constraints that may arise cannot reasonably be allocated to a specific proposal or to existing resources and, therefore, such constraints are addressed in the Entergy and ICT transmission planning process. Hence, so long as the proposed resource can deliver in all years of the planning horizon, then TAG considered the network to be adequate for qualifying the proposed resource. We found this approach to be reasonable.

TAG evaluated 20 proposals. This included all 19 proposals from the Phase I Shortlist [redacted] (as explained above). Of these 20 proposals, ten qualified as network resources without transmission upgrades or delisting. The remaining ten proposals were evaluated to determine what measures would be needed to qualify each of them as network resources. If a resource is able to qualify as a network resource given the existing and planned transmission network, then no transmission delivery costs were assigned to this resource.

Physical Transmission Upgrades. The first step in evaluating what measures were required for these ten proposals to qualify as network resources was to identify necessary transmission upgrades. These physical upgrades were based on securing sufficient transmission capacity in the planning horizon (up through 2018, as discussed above). TAG identified the nature and cost of the upgrades and provided EET with the total cost and the construction schedule so that EET could estimate a stream of revenue requirements for the upgrade. Aside from generator interconnection costs (discussed below), the TAG-identified upgrade costs were potentially lowered because TAG sought to mitigate costs by considering the delisting of existing units. The delisting could reduce or eliminate a proposal's associated upgrade costs. For any upgrade costs remaining, TAG also considered whether redispatch or partial deliverability could address interim transmission capacity deficiencies until physical network upgrades could be placed in service.

Delisting. Delisting a network resource is the process of removing its network designation in order to free up transmission capacity that can then be used to integrate the network customer's loads and generation resources. The freed-up capacity is then released and can be used by a newly-designated resource to qualify it (in whole or in part) as a network resource. For proposed resources for which a delisting option was available, the needed transmission upgrade costs could be mitigated by the delisting due to the reduced capacity required for network integration. Delisting options were identified for four resources, as shown in Table 9.

Table 9: Delisting Candidates

Proposal Resource	Location	Resource Capacity (MW)	Delist Candidate	Delist Capacity (MW)
[redacted]				

Delisting costs were estimated by the EET. EET established the per-MW cost of replacing delisted capacity based on the estimated cost of a 10,000 BTU/kWh heat rate call-option purchase. This is a reasonable approach because delisted capacity will need to be replaced during peak periods, when it is needed again to meet network load. Hence, the 10,000 BTU/kWh heat rate call-option purchase is a reasonable estimate of replacement capacity for the delisted units. Delisted capacity was assumed to be replaced on an annual basis and for each year of the proposal term.

EET estimated the cost of 10,000 BTU/kWh heat rate call option to be [redacted] in 2010. This estimate is based on the ESI estimate of market-based prices for energy options from actual purchase data. In particular, recent market purchases of power were compared to estimated running costs of resources supporting such purchases. The difference between the market price and the estimated running cost was the basis for the capacity payment. Thus, the price of the capacity component depended on its heat rate. Once EET estimated the delisting costs, this estimate was compared to the upgrade costs that could be saved by the delisting. If the delisting costs were less than the upgrade costs, then the delisting was assumed to be operative in the final deliverability cost estimates. It turned out that in all instances where the delisting was feasible (as shown in Table 9, above), the costs associated with the delisting were greater than the cost of the avoided upgrades. As a result, no delistings were implemented for the RFP evaluation.

Mitigation of Upgrade Costs. If a resource's transmission upgrades are not expected to be in service during an initial period of a proposal's term, TAG made a further analysis of measures that could mitigate the transmission requirements. These are redispatch costs and partial deliverability costs. Both of these categories of mitigation were only considered as interim measures until upgrades could be completed. In the event an upgrade for a proposal was not anticipated to be ready in time for the commercial in-service date, and mitigation measures were not available, the proposal was evaluated with a delayed in-service (or delayed acquisition) date. The proposal costs and benefits for these periods were based on pre-delivery costs and benefits as discussed in Section IV. Only one proposal was evaluated under a delayed in-service date due to the timing of transmission upgrades. [redacted].

<u>Redispatch Scenarios</u>. Generation redispatch scenarios were evaluated to determine if they created enough capacity to allow the proposal to be dispatched without resort to partial deliverability mitigation. When redispatch was a feasible solution for creating transmission

capacity in some period, the EET estimated the cost of such redispatch scenarios. There were two components of this cost: a capacity cost component and an energy cost component.

The *capacity cost component* reflected the reduced capacity from having to unload a network resource to accomplish the redispatch. When a unit is dispatched down to create transmission capacity, that unit is not available to the System. The replacement cost for capacity redispatched down was valued at the estimated cost of a 10,000 BTU/kWh heat rate call-option purchase (about [redacted] in 2010). This is a reasonable approach for the same reason it was used for delistings.

The *energy cost component* is an estimate of the increased energy cost to the System from lowering the output of one existing unit and replacing it with System energy. It is calculated in several steps, based on the assumption that existing natural gas-fired units are dispatched downward and replaced by other System resources.

Because the need to redispatch in order to create transmission capacity will be needed primarily during times of System peak demand, the redispatched quantity varies with the System load. In lower load hours, the redispatch is assumed to be less than in higher load hours. For each year the redispatch scenario was to be in effect, TAG provided the EET with the amount of capacity needed for the redispatch across a range of load levels, with lower redispatch required for lower load levels.

The per-hour redispatch costs were based on a heat rate differential for moving a redispatched (natural gas) unit down from its economic dispatch point. EET determined that natural gas-fired units available for redispatch would, on average, experience a heat rate penalty of about [redacted] for each MW that the units are redispatched to make a resource deliverable to the System. The penalty results from moving away from a dispatch level to a less efficient point on the unit's heat rate curve.[12] This heat rate differential "penalty" is multiplied by the number of MWs the unit is redispatched down and then by the cost of natural gas on a $/MMBtu basis, resulting in an estimate of the cost of downward redispatch on a $/MWh basis. To arrive at the

12 EET identified 23 units being available for redispatch. The slope of each unit's heat rate curve at its midpoint was used as it incremental heat rate. This represented the cost of a one MW redispatch from this unit. This estimate was averaged across all the identified units to determine the average heat rate "penalty" to apply to a redispatch scenario.

yearly energy cost component of the redispatch, this $/MWh estimate was multiplied by the MWh of redispatch. The MWh of redispatch was estimated by EET based on the amount of redispatch required at various load levels as provided by TAG, as discussed above. We found this approach to be reasonable.

Partial Deliverability. A second option for providing transmission capacity for the period when transmission upgrades were being completed was partial deliverability. In particular, the proposal will be evaluated by the EET but the production-cost savings were be scaled down to reflect the fact that the resource was only partially deliverable. EET will calculate the production-cost savings by proposal-month based on the ratio of the MW for which monthly network resource transmission service is projected to be available to the total capacity of the proposal. The estimate of partial deliverability was based on data provided by TAG to EET. In particular, for each year, TAG provided the EET with the amount of capacity available for the delivery across a range of load levels. While we found this approach to be reasonable, partial deliverability did not apply to any proposals.

Summary of Transmission Costs. The TAG analysis for deliverability resulted in transmission costs in four categories: (1) physical upgrade costs; (2) delisting costs; (3) re-dispatch costs; and (4) partial deliverability costs. Of course, some proposals may incur none of these costs at all. We summarize these cost categories below in Table 10.

As noted above, the Table indicates that no proposal was associated with an economically viable delisting alternative. Also, only one proposal could benefit from the redispatch scenario. Several proposals, most notably [redacted] was able to benefit from a specific unit commitment (RMR)-related transmission investment, as explained more below. These costs were more than offset by production-cost savings associated with the newly-created ability for the proposal to substitute for unit commitment rules. Thus, although the Table shows "RMR" to be a cost item, there are corresponding benefits related to RMR mitigation reflected in the production cost savings part of the analysis not shown in this Table.

Table 10: Summary of Network Delivery Costs

Proposal	Plant Name	Location	Proposal Type	MW	Upgrades Network Resource Test ($mil)	Redispatch ($mil)	Partial Deliverability ($mil)	RMR ($mil)	Total ($mil)
[redacted]									

Generator Interconnection Costs. For developmental proposals (which were only considered for Amite South delivery), TAG conducted "Information Only" generator interconnection studies to identify facilities and costs required to interconnect a proposed resource to the Entergy transmission system. The study was based on bidders' submitted applications for interconnection in accordance with the Entergy Open Access Transmission Tariff. The estimated costs were included in the delivery expenses in the net benefit evaluation. TAG also performed "short circuit" analyses to identify any under-rated breakers in the vicinity of the proposed generating facility. These short-circuit analyses did not identify any such breakers. The interconnection costs for each developmental proposal is shown in Table 11.

Table 11: Generator Interconnection Costs

Proposal	Plant Name	Location	Proposal Type	MW	Interconnection Costs ($m)
[redacted]					

Note: Only developmental proposals had generator interconnection costs (see text).

b. Specific Network Resource Unit Commitment (RMR Units)

The Specific Network Resource Unit Commitment evaluation process identified proposals which by themselves, or in combination with identified upgrades, can impact the unit commitment requirements for resources in certain areas. Primarily, the evaluation provides new unit-commitment guidelines for the dispatch of resources to be used in the EET production cost model. This can cause the proposed resources to provide more System production-cost savings than in the case where the proposed resource is not considered for a special unit commitment role.

The process of identifying possible special unit commitment substitutions was conducted on a unit-by-unit basis. Each proposed resource was matched to special unit commitment resources based on electrical location. If the proposed resource was in the electrical proximity of an existing special unit commitment resource, then TAG evaluated whether the proposed unit could perform a commitment role similar to the existing unit. This was determined by calculating the relief that the proposed resources could provide to the constraints that benefited from the special unit commitment resource. This calculation is based on the relative shift factors and unit sizes and is performed on up to five constraints for each special unit commitment resource. If the proposed resource could provide at least the same relief on all the constraints, then it was programmed in Prosym to satisfy the special commitment rule and likely would provide additional production-cost savings. If a proposed resource provided the same constraint relief for all but one of the constraints, transmission upgrades are evaluated that may enable additional special-commitment-related production-cost savings to be realized.

TAG identified the transmission upgrades that could enable a proposed resource to replace existing specific unit commitment resources. This evaluation was conducted in conjunction with EET to determine if the specific unit commitment benefit was greater than the associated upgrade costs to enable the substitution. If so, transmission costs were included directly in the net benefit calculation in a manner similar to other transmission costs and the unit commitment rule in Prosym was adjusted accordingly.

Table 12 shows the proposed resources which TAG identified as capable of replacing existing special unit commitment resources.

Table 12: Special Unit Commitment Displacements

Proposal Resource	Location	Resource Capacity (MW)	Special Commitment Unit to Dispace	Upgrade Costs (000)
[redacted]				

Note Upgrade Costs are those specifically required to achieve the unit commitment displacement.

We monitored this process and found the approach and results to be reasonable.

c. Transmission Cost Adders and Line Losses Consideration

TAG conducted two studies to help EET assess certain transmission issues that could inform final resource selection. The analyses related to real-time transmission congestion costs in the northern part of the System and line losses for delivery to the DSG sub region.

The transmission congestion cost evaluation was conducted based on a proposal's location. TAG evaluated historical congestion indicators to determine which locations experienced congestion in the real-time that was not identified in the planning models. Because the planning models do not account for temporary network resource outages, merchant activity, and QF put transactions, congestion can arise in real-time that was not indicated in the planning models. TAG then identified the physical upgrades that would alleviate such congestion. In essence the real-time congestion costs were assigned to units that contribute to congestion on a constrained interface. These costs were used as sensitivity and were not part of the main transmission cost analysis.

The line-loss analysis was conducted for proposals located outside of DSG that were evaluated to meet the Amite South capacity need. It was used only in net benefits calculations for non-AMS CCGT serving AMS. For each proposal, TAG calculated the per-MWh incremental line loss for a representative hour of the summer, winter, and shoulder periods. EET then used these line losses to estimates the cost of serving AMS from outside the region. This is explained in more detail, below, in subsection I.A.4.

d. Amite South Transmission Analysis

TAG also produced two analyses for transmission delivery to Amite South. These are discussed below in our presentation of overall findings regarding the Amite South evaluation in subsection I.A.4.

2. Updated Fixed Costs and Production-Cost Savings Results

As indicated above, the Phase II net benefits analysis was a refinement and update of the Phase I net benefit analysis. The refinement included, in addition to the transmission deliverability analysis discussed above, updates to the key offer parameters. This included new offer parameters for proposals that accepted the invitation to submit best-and-final offers. It also included refined parameters resulting from preliminary due diligence by VAT and TAG which addressed key issues such as heat rates, plant upgrades, operating capability, emission rates, and operating flexibility. This was conducted by VAT subject matter experts as well as VAT and TAG meeting directly with bidders (under IM oversight). These meetings were supplemented with multiple rounds of clarifying questions in order to ensure that information was accurate and up-to-date.

The Phase II net benefit analysis, like the Phase I net benefit analysis used ESI's "Fundamental Analysis" to estimated levelized fixed cost of the proposal and used Prosym to measure the incremental production cost benefit of adding a proposal to the System (or to EAI and EMI separately). The fixed-cost estimates were updated based on the best-and-final offers and based on any adjustments deemed warranted by the VAT and TAG preliminary due diligence.

a. Changes in Fixed Costs

Table 13 shows the difference between the Phase I fixed cost estimates and the Phase II fixed cost estimates.

Table 13: Change in Fixed Costs between Phase I and Phase II Evaluations

Proposal	Plant Name	Proposal Type	Phase I Fixed Costs (/kW-yr)	Phase II Fixed Costs (/kW-yr)	Change from Phase I (/kW-yr)	Percentage Change
[redacted]						

We monitored the evaluation and analysis that led to changes in fixed costs between Phase I and Phase II for all proposals. Because some proposals experienced a substantial rise in fixed cost between the two phases, we will discuss here the proposals that experienced the highest percentage increases. [redacted] experienced the most significant increases to fixed costs. Between the two phases of the evaluation [redacted] experienced significant changes on a percentage basis, but on an absolute basis the increase was relatively small [redacted]

[redacted]

[redacted]

We monitored these major adjustments and found them to be reasonable and properly implemented.

b. Changes in Production-Cost Savings

As with the fixed-cost analysis, the production-cost analysis was also revised in Phase II. This was primarily due to revisions to Prosym to reflect the ability of proposed resources to substitute for specific unit commitment. But other minor issues warranted modeling adjustments, such as updates to fuel cost and updates to the offer parameters in best-and-final offers.

Table 14 shows the difference between the Phase I production-cost savings estimates and the Phase II production-cost savings estimates. These estimates are for resources analyzed for meeting System-wide needs. This comparison is sufficient to illustrate the changes in production-cost savings because changes in the production-cost savings on a System wide basis will reflect factors that will also be present to a comparable degree in production-cost savings analyses for meeting the needs of Amite South, Entergy Arkansas, or Entergy Mississippi.

The updated production cost model shows substantial increases in production-cost savings for the [redacted] proposals. In all four instances, the increase in production-cost savings was the result of new specific unit commitment rules that allowed these resources to substitute for an existing System unit that satisfied the commitment rules.

In summary, our analysis of the Phase II benefits and costs compared to Phase I did not reveal anomalies that would suggest problems with estimation methods or results.

Table 14: Change in Production-Cost Savings Estimates between Phase I and Phase II

Proposal	Plant Name	Proposal Type	Phase I Produciton Cost Savings (/kW-yr)	Phase II Produciton Cost Savings (/kW-yr)	Change from Phase I (/kW-yr)	Percentage Change
[redacted]						

3. Phase II Net Benefits Results

Based on the additional transmission analysis as well as the revised cost analyses, Table 15 shows the Phase II net benefit results for the System delivery (the other delivery analyses are shown subsequently).

Except for "Delivery Expenses", which is a new cost category reflecting the TAG analysis, the various cost categories in the Table are the same categories as in the presentation of Phase I results above (in Table 3, for example). We repeat a description of them here in abbreviated form for the reader's convenience. A levelized value represents a single fixed value (cost or benefit) which, if it were incurred in each period of the proposal, a stream of this levelized constant value would produce a present value equivalent to the present value of the actual projected stream. Levelized Fixed Expenses are the levelized values produced by ESI's Fundamental Economic Model. These are the option premium or acquisition (non-fuel) revenue-requirement cost. "Imputed Debt" reflects the incremental finance cost to the Entergy Operating Companies from entering a purchase power agreement. Accordingly, they only apply to PPAs. Production-cost savings are the Prosym estimates of production-cost savings. Other Proposal Benefits consist of pre-delivery benefits, post-delivery benefits, and supplemental capacity benefits, as discussed in connection with the Phase I evaluation.

Table 15: Phase II Net Benefits – System Delivery

Proposal	Plant Name	Region	Proposal Type	MW	Fixed Exp. (/kW-yr)	Delivery Expenses (/kW-yr)	Imputed Debt (/kW-yr)	Production Cost Savings (/kW-yr)	Other Benefits (/kW-yr)	Net Benefit (/kW-yr)
[redacted]										

Net benefits are calculated as the sum of the benefits and the three categories of costs. As Table 15 shows, net benefits from the Phase II evaluation for System delivery range from a high value of [redacted] to a low value of [redacted]

As a final analysis, Table 16 shows a comparison of Net Benefits between Phase I and Phase II along with the change in ranking. This helps illustrate the effect of the additional Phase II analysis on the final evaluation results.

Table 16: Change in Net Benefits between Phase I and Phase II – System Delivery

Proposal	Plant Name	Proposal Type	Phase I Net Benefit (/kW-yr)	Phase II Net Benefit (/kW-yr)	Change from Phase I (/kW-yr)	Percentage Change	Change in Ranking from Phase I
[redacted]							

The entries in Table 16 are sorted in accordance with the column titled "Change in Ranking from Phase I". The Table shows that the Ninemile self-build proposal exhibited the most significant change in ranking, moving from the 16th ranking to the 8th ranking. As shown above, this was due to favorable changes in both fixed costs and production-cost savings. [redacted]

As discussed above, we monitored the major factors affecting the final Phase II Net Benefits results (delivery expenses, changes in fixed cost, and changes in production costs) and found the changes in the individual components of the Net Benefit analysis to be reasonable. Accordingly, we find the Phase II Net Benefit values to be reasonable.

Our conclusions extend to the Phase II net benefit analysis for Entergy Arkansas and Entergy Mississippi. Recall from the Phase I discussions that ESI conducted the economic evaluation under the assumption that Entergy Arkansas and Entergy Mississippi would follow through on their plans to exit the System Agreement. Hence, for Entergy Arkansas and Entergy Mississippi, separate net benefit analyses were necessary in order to measure the potential benefit of choosing a resource allocated to one of those two companies. The results of these analyses are shown in Table 17 and Table 18. Comparing these results to the Phase I results in Table 4 and Table 5 indicates that the rankings did not change significantly between Phase I and Phase II.

Table 17: Phase II Net Benefits – Entergy Arkansas

Proposal	Plant Name	Region	Proposal Type	MW	Fixed Exp. (/kW-yr)	Delivery Expenses (/kW-yr)	Imputed Debt (/kW-yr)	Production Cost Savings (/kW-yr)	Other Benefits (/kW-yr)	Net Benefit (/kW-yr)
[redacted]										

Table 18: Phase II Net Benefits – Entergy Mississippi

Proposal	Plant Name	Region	Proposal Type	MW	Fixed Exp. (/kW-yr)	Delivery Expenses (/kW-yr)	Imputed Debt (/kW-yr)	Production Cost Savings (/kW-yr)	Other Benefits (/kW-yr)	Net Benefit (/kW-yr)
[redacted]										

4. Amite South Evaluation

Phase II also develops estimates of the benefits and costs for CCGT resources to meet the specific Amite South capacity need (in Phase I, resources were evaluated to meet only System-wide, Energy-Arkansas, or Entergy Mississippi capacity needs). The evaluation estimated net benefits in the same manner as in the evaluation for System-wide resources; it compared production-cost savings and other benefits to proposal fixed costs.

a. Production-Cost Savings

The production cost savings used to evaluate AMS proposals was based on the System-wide production-cost savings used in the System-wide net benefit analysis (see Table 15). The System-wide production-cost savings were adjusted to account for the fact that proposals located outside of AMS (and some inside AMS) would incur additional losses to deliver to the DSG location. Hence, EET sought to reflect the line-loss costs in the analysis.

To do this, TAG provided EET an estimate of the incremental line losses associated with each proposal for delivery to DSG. Incremental losses were generally in the 3 to 5 percent range, but

DSG-sited resources were close to zero and some resources located outside of AMS had incremental losses of over 7 percent. The incremental losses were used to increase the per-MW variable production cost by the same percentage as the losses. Hence, a 5-percent incremental loss factor for a resource increased that resource's variable production cost per MWH by five percent. This additional loss-related production cost was the loss cost and was used to reduce the annual Prosym production-cost benefits. We found this approach to be reasonable.

Table 19 shows the original production-cost benefits of each proposal, the proposal's line loss costs, and then the AMS Production-Cost Savings. For this Table, production cost saving includes post-delivery benefits, which are relatively small but reflect production cost savings after the offered term of delivery. We include this because it is affected by the loss cost calculation. The final net benefits for AMS are discussed below.

Table 19: Levelized Cost of Losses for AMS Delivery

Proposal	Plant Name	Region	Proposal Type	MW	System-Wide Production-Cost Savings ($/kW-yr)	AMS Loss Cost ($/kW-yr)	AMS Production Cost Savings ($/kW-yr)
[redacted]							

b. Amite South Transmission Analysis

The AMS transmission analysis addressed two possible upgrade costs associated with any given proposals: (1) upgrade costs to enable delivery of CCGT capacity into AMS (AMS Resource Costs); and (2) upgrade costs to restore the AMS interface limits if a proposal's dispatch reduces this limit (AMS Interface Costs). In addition to these costs, the delivery costs to qualify the resources as network resource on a System-wide basis were also included in the total AMS transmission costs. These are the delivery expenses the System-wide net benefit analysis from Table 10 and Table 11. As a result, the AMS transmission expenses are at least as high as the System-wide delivery expense.

Amite South Resource Test. The AMS Resource Test identified the additional upgrade costs (above the cost identified in the network resource test) to make a CCGT proposal further deliverable to the AMS region and into the DSG sub region of AMS. The upgrades were identified by considering a "transfer case" that started from the base case without the proposed resource and then simulated a substitution of the proposed resource for the existing Entergy units in AMS. TAG then identified any transmission constraints caused by this transfer case. We found this approach to be reasonable.

Amite South Interface Test. The AMS Interface test identified the additional upgrade costs required to return the AMS Interface to its original limit if the limit had been reduced based on delivering any specific resource proposal into AMS. In this evaluation, TAG assessed the transmission impact of each resource to determine any effect on the transmission limits into AMS. These transmission impacts were associated with resources located close to the AMS interface.

For both tests, the cost of satisfying the requirement was provided to EET to include as a cost in the net benefit analysis. Table 20 shows the AMS transmission costs for all proposals. It shows the AMS Resource Test costs, Amite South Interface Test costs, and the Network Resource Test costs.