INDEPENDENT MONITORING OF THE EVALUATION OF PROPOSALS FOR ENTERGY LONG-TERM SUPPLY-SIDE RESOURCES

CCGT FINAL REPORT

August 2007

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CONFIDENTIAL MATERIAL REDACTED

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Note: Confidential text material, Tables, and Figures in this report have been redacted.

I. OVERVIEW

A. Introduction

On April 17, 2006, Entergy Services, Inc. ("ESI") issued a request for proposals to procure long-term supply-side resources for the Entergy operating companies ("2006 Long-Term RFP"). This was the latest in a series of RFPs that ESI has issued since 2002 under the RFP process established in response to the competitive bidding requirements of the Louisiana Public Service Commission.[1] The RFP process is intended to establish fair criteria to process, evaluate, and select among competing proposals to provide long-term power supply products.

Integral to the competitive bidding process is the requirement that ESI retain an independent monitoring function for processing and evaluating proposals. In December 2005, ESI retained independent monitors. The monitoring roles were divided between monitoring the RFP process and monitoring the RFP evaluation. Energy Associates, led by Ms. Elizabeth Benson, was selected as the "Process IM" and Potomac Economics, led by Dr. David Patton, was selected as the "Evaluation IM".[2]

The power supply products that ESI sought to procure in the 2006 Long-Term RFP were based on the Entergy Operating Companies' resource planning objectives. ESI identified a need for combined-cycle gas turbine ("CCGT") capacity and solid-fuel baseload capacity. The RFP process and evaluation for the two types of capacity are similar in many regards but are distinct and are conducted separately. This report addresses the evaluation of the CCGT proposals. A separate report to be filed at the Louisiana Public Service Commission addresses the evaluation of the Solid Fuel proposals.

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[1] General Order, Docket No. R-26172 Subdocket A, *In re: Development of Market-Based Mechanisms to Evaluate Proposals to Construct or Acquire Generating Capacity to Meeting Native Load, Supplements the September 20, 1983 General Order,* dated February 16, 2004.

[2] The responsibilities of the Process IM and the Evaluation IM are set forth in the Independent Monitoring Scope document posted to the RFP website https://emo-web.no.entergy.com/ENTRFP/.

B. Summary

The ESI evaluation provides a quantitative estimate of the economic benefits of each proposal as well as an assessment of qualitative factors through a due diligence review. Both the economic evaluation and due diligence review were within the scope of the Evaluation IM. The economic benefits were calculated based on estimated proposal costs netted against projected system-wide production-cost savings. The due diligence review assesses certain qualitative aspects, such as operational experience and flexibility, fuel supply, and counterparty characteristics.

The economic evaluation was in two stages. Originally, the first stage was a preliminary screen to identify the most economic proposals to advance to a more detailed Stage 2 evaluation based mainly on the cost of each proposal. However, at the request of the Louisiana Public Service Commission, the RFP process was accelerated. This resulted in ESI including additional analysis in Stage 1 that was originally planned for Stage 2. In particular, the production cost benefits that were to be estimated by production-cost simulation (using PROSYM) in Stage 2, became part of the Stage 1 evaluation. Accordingly, the Stage 1 results and rankings were based on net benefit estimates (i.e., as-offered costs net of production-cost savings).

There were 35 CCGT proposals submitted in response to the RFP. Based on the estimated net benefits, 17 of them were selected to advance to a more detailed Stage 2 evaluation. As a result of the accelerated RFP process, Stage 2 primarily focused on the preliminary due diligence review and revisions to the original economic evaluation associated with the best-and-final offers being provided by the bidders.

Two proposals were subsequently withdrawn prior to completion of the Stage 2 evaluation, leaving 15 proposals at the end of Stage 2. The 15 proposals were comprised of 5 distinct projects.[3] The highest-ranking proposals were from an 800 MW project which is associated with 9 of the 15 proposals. These 9 proposals differed as to transaction type (i.e., purchase power v. acquisition, capacity, and extension terms). As a group, these proposals were consistently more highly ranked from an economic perspective relative to the other proposals and also compared

3 Many plant owners submitted multiple proposals which varied in their proposal parameters, e.g., capacity amounts, extension options, etc.

well with regard to the preliminary due diligence review. Accordingly, ESI selected these proposals for further negotiation and final due diligence.

The negotiations and final due diligence led to a final decision between the parties to enter into an agreement whereby ESI is to acquire the entire 800 MW plant.

In the course of monitoring the evaluation of the CCGT proposals, we reviewed a large number of relevant documents and other materials, and closely monitored the structure and results of the evaluation models. We have concluded that the models and underlying assumptions were reasonable and accurately estimated the cost and benefits of the proposals. We also found that that criteria used to make the final selections were fair and impartial, and that judgment used in the process was sound. Accordingly, we find the overall evaluation to have been conducted in a fair and impartial manner.

C. Organization of Report

The remainder of the report is organized as follows. In Section II we discuss preliminary activities prior to actual evaluation of proposals. This includes the development of the RFP, participation in technical conferences, and our preliminary monitoring of the evaluation tools. In Section III we describe the Stage 1 evaluation. In Section IV, we describe the Stage 2 evaluation and the final selection.

II. PRELIMINARY ACTIVITIES

A. Draft RFP

Following ESI's selection of Potomac Economics as Evaluation IM in December 2005, Potomac Economics received a draft RFP for review and comments. A significant portion of the RFP addressed procedural issues that are within the scope of the Process IM. Our focus was on the economic evaluation issues.

The language in the draft RFP was general enough that our comments for specific changes were minimal. Overall, we found the fundamental approach to the economic evaluation described in the RFP to be reasonable. The intent of the evaluation was to develop objective measures of cost and system benefits that provide a quantitative basis for ranking each proposal. The presentation of the economic evaluation (including the transmission evaluation) did not include all details of the analysis. This is understandable given the complexities involved. However, we cited the need to provide clarity in a number of areas relating to both the economic and the transmission evaluation. In particular, we asked for more clarity in instances where the exposition was unclear or incomplete. A main area where more clarity was needed involved the discussion of the transmission evaluation performed by ESI and how it was to be integrated into the overall economic evaluation. Furthermore, we had questions about how the subsequent results of the transmission analysis by Entergy's Transmission Business Unit ("TBU") would be incorporated.

We also inquired regarding the rationale for treating certain operating parameters (e.g., fixed operation and maintenance (O&M) and variable O&M) as fixed for purposes of the preliminary ranking of the proposals even if the participant submitted other values. This essentially reduces suppliers' offer flexibility and can compel them to adjust their acquisition price (for an acquisition) or their option premium (for purchase power agreement (PPA)) in response to this inflexibility.

Issues relating to both the transmission analysis and the fixed offer parameters were resolved to our satisfaction through revisions to the RFP and through clarifying discussions with the ESI RFP team.

A final area where we raised concerns was in the credit evaluation section. We raised questions about the source of the collateral requirements, as well as the requirements associated with a letter of credit required of bidders who advance in the RFP selection process. With respect to the collateral requirements inquiries, the ESI RFP team indicated that these requirements reflected the standard requirements ESI would apply to independent contractors it employed on other ESI projects. With respect to the Letter of Credit, this was initially to apply to bidders with insufficient credit worthiness but was later revised to apply to all bidders in a non-discriminatory manner. ESI explained to us that the purpose of the letter of credit was to allow ESI to draw on the credit in the event of damages arising from bad faith bargaining in the negotiation phase. ESI did not agree to a reciprocal arrangement with the counterparties. Finally, we had concerns about a lack of flexibility regarding credit worthiness that may prevent an otherwise economical project from a financially constrained bidder from being considered. We proposed bidders be allowed to compensate for this risk. We monitored for such situations to help ensure fairness.

We did not find a way to resolve the credit these issues within the RFP draft. However, we felt confident that in the course of monitoring the evaluation we would have the opportunity to ensure credit issues that adversely impacted proposal could be addressed fairly. In retrospect, no credit issues arose that impacted the evaluation process.

In summary, we were satisfied that the ESI RFP team was concerned about and responsive to issues that we raised in the initial RFP drafting process regarding the evaluation.

B. Economic Evaluation Monitoring

We began our more detailed monitoring of the evaluation methods in February 2006. While we had familiarized ourselves with the general evaluation process in assisting in the RFP draft, we had not received the detailed methodologies and models. At a February 21 meeting, the ESI economic evaluation team (EET) provided a draft version of the Excel spreadsheet model that underlies the economic rankings that are the core objectives of the initial phase of the evaluation process. During most of the two-hour meeting, the EET discussed the various elements of the model and answered our questions about its main functions.

Subsequent to this meeting, Potomac Economics undertook a further analysis of the model. The model produces a unique summary spreadsheet for each offer. This summary spreadsheet is divided into several sections. The first three sections identify the inputs and assumptions taken directly from the proposal (e.g., option premium, heat rate, start date, stop date, VOM cost, etc.) and applicable ESI inputs and assumptions (e.g., capacity factor, term of the RFP). These sections also include the inputs associated with the transmission benefits estimated by ESI Transmission Analysis Group (TAG). The TAG issues are discussed separately below. Based on our initial review, we concluded the spreadsheet tool was a reasonable approach to estimating costs. With respect to the inputs from the transmission analysis, these inputs embody an extensive and critical set of assumptions and analysis. We comment further on these items in the discussion of out monitoring of the proposals in Section III.

Each proposal's bid parameters and ESI inputs and assumptions are used together to develop a stream of costs associated with each proposal over the term of the RFP. The stream of costs is developed first. As indicated in the RFP, when a proposal does not exactly coincide with the start and stop dates in the RFP, ESI estimates the cost of replacing the project for time when the project does not overlap with the time period established in the RFP. This cost is part of the total stream of proposal costs. For each year of the proposed project, the spreadsheet model calculates total fixed costs and total variable costs (fuel plus variable O&M). For PPAs, fixed costs include fixed O&M and the option premium. 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).

An additional annual fixed cost is estimated for capital investments in transmission assets required to integrate the proposed resources (i.e., to obtain network service). These costs are based on the annualized capital costs of the investment. Transmission costs are reduced by any annual transmission benefit provided by the resource. These costs and benefits are provided by TAG after a detailed analysis of the transmission system benefits. We discuss this in more detail below in Section III.

Using the annual estimates of fixed and variable 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.

C. Technical and Bidders Conferences

On February 23, 2006, ESI and LPSC jointly held a Bidders and Technical Conference, attended by the IMs, LPSC staff, and interested bidders. The ESI RFP evaluation team provided an overview of the RFP process consistent with the information the team had provided to us during the previous two months. The LPSC staff asked a series of questions and the responses we heard were consistent with the indications the ESI evaluation team had conveyed to us on the same issues. Likewise, the few potential bidders that made inquiries during the conferences received responses that were consistent with what the ESI evaluation team had conveyed to us during the RFP drafting process.

Following the technical conference, ESI received a number of data requests emanating from the bidders' conference in February. We were asked to review the responses and we were satisfied that ESI provided reasonable responses.

D. Analysis of Models and Processes

At the end of March 2006, we received a revised version of the ESI economic evaluation spreadsheet model and we began a detailed analysis. Our analysis raised two main questions involving certain missing data associated with values that were to be used for the evaluation from other analysis. This included the "transmission benefits", which would be estimated by the TAG, and the "PROSYM benefit". We were assured that the nature of these calculations would be explained in subsequent meetings. (These meetings subsequently occurred later in April as explained below).

We made inquiries into the definition of several terms, including *supplemental capacity benefit*, and *net benefit (in conjunction with the PROSYM estimates).* We also inquired into the basis of certain assumptions including the capacity factor, number of starts, shape of pre-delivery purchase power prices, terminal value benefit, and post-delivery capital recovery costs. Finally, we found some minor errors in the formulas that we recommended be corrected. We were satisfied with our discussion of these issues and the changes agreed to by ESI.

Further meetings in April with ESI involved finalizing the details of the evaluation procedures. On April 12, there was a conference call on details of the final draft RFP. Neither we nor the Process IM proposed any fundamental changes but we did clarify certain evaluation processes. There were two improvements: (1) introducing the ability to raise solid-fuel bids after a proposal made the "short-list" via declaring specified cost elements in advance, and (2) ESI accepting the potential of offering "credit support", i.e., earnest money to counterparties.

On April 17, there was a conference call on the PROSYM modeling. PROSYM is a production cost modeling tool that estimates the optimal dispatch of generation to meet system load given operating and physical delivery constraints. As discussed further herein, the EET will be using PROSYM in the evaluation process to determine system benefits related to fuel, purchased power, and variable operating costs. The system benefits will be netted against the unit's proposed bid costs to reflect fully the economics of the unit. There were a few clarifying questions in response to the presentations but no fundamental issues were raised.

On April 21, 2006, the Fuel Evaluation Team provided a presentation via teleconference that showed data and models for fuel price forecasts. We identified no substantive issues in this presentation.

On April 27, an RFP "walk-through" of the entire RFP process was presented. The presentation indicated how the bidders' data would "feed" into the economic evaluation. The evaluation teams had run a sample proposal through each of their analysis and created a spreadsheet that illustrated the output of each analysis. These simply showed what data would be passed to EET. The EET, the FET, and the TAG each made brief presentations and fielded questions.

The most informative presentation from the monitoring perspective was the TAG presentation where a significant amount of detail was revealed regarding the methods of calculating transmission-related costs and benefits. This was an area where our monitoring had required additional information and the meeting provided it. More detail on the TAG analysis and models is presented in the next section along with our monitoring efforts during the actual evaluation.

III. MONITORING OF STAGE 1 EVALUATION

On May 1, 2006 the submission of proposals began and extended through May 5. There were 35 proposals submitted that represented 12 distinct resources (some suppliers bid multiple proposals for the same resource). The Process IM confirmed that all 35 proposals were "conforming", meaning they met the basic criteria on the bidding form, e.g., the unit was actually a CCGT and the on-line bidding form was properly completed.

The RFP evaluation team began its Stage 1 evaluation when proposals were deemed "conforming" by the process IM, which occurred on May 5. The Stage 1 analysis is used to determine the most economic proposals that would advance to the Stage 2 analysis. As discussed above in subsection II.B, the economic evaluation model used in Stage 1 produces an estimated levelized cost made up of five main elements:

(1) operating costs of the unit;
(2) option premium or acquisition price;
(3) pre-delivery and/or post-delivery supplemental power costs;
(4) transmission benefits; and
(5) network transmission access costs;

The Stage 1 evaluation proceeded in three steps. The first step is a Stage 1-A analysis that determined the estimated levelized cost for each proposal based on the first of the items listed above. The lowest-cost proposals are selected as "Candidate Proposals" that are to advance in the evaluation process. The second step is the Stage 1-B analysis that determines certain estimated transmission benefits from an "initial transmission analysis". This initial analysis reflects the costs of (4) as discussed more below. The Stage 1-B analysis is meant only to designate additional Candidate Proposals by virtue of potential transmission benefits that were not reflected in the Stage 1A analysis.

The finalized Candidate Proposals from Stage 1-B are those that are to be sent to TBU for a system impact study. However, prior to submission to TBU, a third step in Stage 1 is conducted. This is the Detailed Transmission Evaluation ("DTE") for all Candidate Proposals to estimate delivery costs (item (5) above). This DTE serves two purposes. First, it provides insight into the instructions to be included in the transmission requests to TBU. For example, as explained below, certain delisting alternatives may provide a lower-cost transmission option for some proposals. Second, the estimated delivery costs from the DTE can be used instead of the actual TBU system impact study ("SIS") results in the event the TBU results are not completed in a timely manner. In this way, the DTE ensures the evaluation progresses within the RFP timeframe.

The RFP evaluation team ultimately decided to designate all proposals as Candidate Proposals. However, these proposals advanced in two tranches. The Primary Tranche (the 18 lowest-cost proposals) was given priority with respect to analysis by TBU to help ensure TBU would return the SIS results for at least these proposals in a timely manner. The bifurcation of the Candidate Proposals was done using the Stage-1A and Stage 1-B analyses and is discussed in more detail below.

A. Stage 1-A -- Initial Economic Evaluation

The Stage 1-A evaluation uses the bidder's offer parameters (e.g., unit size, heat rate, variable O&M) along with ESI-provided assumptions (e.g., pre-delivery and post-delivery supplemental power costs) in order to estimate a stream of costs associated with each proposal to provide energy to the system. The stream of costs is then levelized to provide underlying ranking of the proposals. This analysis uses the spreadsheet model introduced above. We monitored the calculation of these results and found them to be reasonable and accurate.

The 35 proposals had levelized Stage 1-A costs ranging from [redacted]. The average Stage 1-A cost was [redacted] and the median was [redacted]. Of these 35 proposals, the evaluation team sought to form a subset of proposals to advance in the evaluation as Candidate Proposals. As indicated above, all proposals advanced as Candidate Proposals, but the Stage 1-A cost analysis divided the proposals into two tranches. The first tranche or the "Primary Tranche" was designated based on the top 18 proposals ranked by levelized costs. The subset was formed with an initial cut-off at the top 18 proposals. This represented just over one-half of the total proposals.

There were seven other proposals with ranks greater than 18 that were added to the Primary Tranche because they were at the same location as one of the top 18 proposals. Adding these to the Primary Tranche was logical because the transmission studies that are conducted on Candidate Proposals will be location specific and there is no additional effort to calculate these costs and benefits for proposals with the same locations. Figure 1 shows distribution of the proposal costs.

Figure 1: Levelized Cost of Proposals

Redacted

The Primary Tranche includes the top 18 proposals and the higher-costs ones that are Candidate Proposals only because they share a location with a proposal in the Primary Tranche. However, in order to illustrate the relative costs of the Primary and Secondary Tranches, the figure excludes proposals that were included in the Primary Tranch by virtue of their location (this explains why proposals ranked 34 and 35 do not appear). As the figure shows, a significant change in costs occurs between the 18^{th}-ranked proposal and the higher-ranked ones. Based on this, we deemed the cutoff at the 18^{th} ranked proposal for submission to TBU to be reasonable. The remaining proposals were designated as Candidate Proposals to advance as a Secondary Tranche.

B. Stage 1-B -- Initial Transmission Analysis

Before finalizing this Primary Tranche of advancing proposals, Stage 1-B of the evaluation was conducted to determine whether any of the proposals beyond the cutoff point (those in the Secondary Tranche) have favorable transmission characteristics that improve their economic standing relative to the Primary Tranche. This is the Initial Transmission Analysis ("ITA") and it is conducted by TAG.

The ITA provides two key values to the economic evaluation: (1) a preliminary estimate of transmission benefits and (2) a qualitative indicator of whether or not the unit faces relatively more transmission constraints than other proposals. The more significant of these two values is the estimate of transmission benefits. This is a quantitative estimate of benefits that may reduce (but not increase) the levelized costs estimates from Stage 1-A.

1. Transmission Benefits

The estimated transmission benefits is composed of three elements: (1) the cost savings from relief of any Reliability-Must-Run constraint; (2) the cost savings from providing counterflow on constrained interfaces; and (3) cost savings from delaying planned transmission projects.

a. Reliability Must Run Benefits

There are a number of generating units on the Entergy system which are sometime instructed to operate in order to satisfy transmission reliability requirements, irrespective of the unit's relative economics. These are referred to as Reliability Must Run ("RMR") units. The associated requirements to run such units for transmission purposes are referred to as RMR constraints. The identification of RMR constraints and RMR units is conducted by TBU.

TAG assigns a value to each RMR unit intended to reflect what the system savings would be if the unit was no longer required to meet RMR requirements. In particular, the method estimates the cost saving that would occur if the RMR unit was replaced with a market purchase. This savings is based on a simple formula that multiples the number of hours the RMR unit is expected to run in a year by the variable cost differential between the RMR unit and the forecasted purchase. This savings assigned to any proposal that was able to provide the same reliability benefit as the existing RMR unit.

The determination as to whether a proposal could replace an existing RMR unit was based on whether the transmission flows associated with the proposed resource would provide relief to the same facilities as the existing RMR unit. While this method is simple, it does provide an indication of the potential savings from each proposal. And while more complex methods could have been employed to refine the estimate, we are satisfied that this method balances the need to obtain a reasonably accurate estimate of benefits with the objective of using transparent and tractable metrics.

TAG identified two existing RMR units that would be candidates for replacement by the proposals. These were [redacted]. We identified the other existing RMR units (there were eight of them) and compared their location to the location of the proposed units. It was evident that no proposal was likely to provide the same reliability benefit of any of the other existing RMR units. Accordingly, we are satisfied that it was reasonable for TAG to focus only on these two existing RMR units.

For these two existing RMR units, TAG then determined whether any proposed resource could provide the same relief as either of the two units. The analysis relied upon an examination of a proposed unit's generation shift factors ("GSFs") on RMR constraints. GSFs indicate what portion of a plant's output will flow on individual transmission elements. Entergy identified, and we verified, that only one proposed unit met this criterion (and this proposal was already designated as a Candidate Proposal in the Primary Tranche).

b. Counterflow Benefits

The second element of the ITA is estimating counterflow benefits provided by each proposal on ESI's internal interfaces. There are three internal interfaces between the four Entergy Planning Regions: North to Central; Central to WOTAB; and Central to Amite South. TAG estimates a marginal value for providing counterflow on each interface. This estimate is based on 4 simulated dispatches, each assuming a new generic 500 MW CCGT in each of the four planning areas. The difference in cost savings between any two of the simulations represents the estimated savings from increasing flow between the regions. For example, if locating a 500 MW CCGT in the North results in $10 million in annual savings while locating one in Central results in $90 million in savings, then the benefit of increasing the interface from North to Central is $80 million or $160,000/MW-year. Table 1 is a summary of the estimated counterflow benefits for each interface.

Table 1: Estimated Counterflow Benefit by Interface

Redacted

Given the three counterflow values, TAG then identified the transmission element that most limits the transfers between the regions. The GSFs for each proposal were used to determine the amount of counterflow that each proposal would create on this most constraining element. The estimated counterflow in MW was multiplied by the counterflow benefit to arrive at the final value for the proposal. If the counterflow was negative (i.e., the proposal actually contributed to the constraint, the values assigned was $0. Of the 35 proposals, [redacted] were assigned some level of counterflow benefit. The most common source of counterflow benefits was on the [redacted] interface, which was indicated on [redacted] of the proposals. [redacted] We monitored this process and verified that it was accurately conducted in accordance with the stated procedures.

c. Benefits from Delay in Transmission Projects

The third element of the ITA is any cost savings a resource may create as a result of delaying a transmission project. If a resource is located where it may relieve flows on facilities slated for upgrades, the project may be delayed, providing a cost savings to the system. We examined the list of planned upgrades and located them on the transmission map. We then examined these locations with respect to the location of proposed resources. We analyzed each resource with respect to the planned upgrades and concluded, as TAG did, that no proposal was likely to have a significant effect on any of the planned upgrades.

2. Qualitative Congestion Indicator

As pointed out above, the ITA has two elements. The first just described is the transmission benefits. The second is the qualitative indicator of relative transmission congestion. The purpose of this indicator is intended to recognize resources that may have relatively lower transmission cost upgrades to integrate with the ESI system. We checked the results of the TAG analysis and are satisfied that the indicator was properly assigned to each proposal.

3. Initial Cost Rankings

As noted above, the purpose of the ITA is to determine whether any benefits are sufficiently high for any proposal to improve its status in Stage 2. Originally, Stage 2 was to evaluate only a subset of proposals and so the ITA was to determine whether that subset identified in Stage 1-A was to be enlarged as a result of ITA. Because the evaluation team had decided to send all proposals to Stage 2 in two tranches, the ITA is used only to determine whether any proposal in the Secondary Tranche should be moved to the Primary Tranche.

Figure 2 shows the original ranking of proposals with the Stage 1-A "break" shown. After adjusting the original costs by the ITA benefits, there are four proposals that were originally beyond the Stage 1-A "break" that have costs comparable to the proposals included in the Primary Tranche. Based on this, the evaluation team decided to move these four proposals to the Primary Tranche for the purposes of further advancing the proposals in the RFP process. We found this to be reasonable.

Figure 2: Stage 1-A Ranking and Stage 1-B Cost Estimates

Redacted

In summary, 29 of the 35 proposals were placed in a Primary Tranche for the next part of the Stage 1 analysis, while the remaining 6 are in the Secondary Tranche. Because the bifurcation into Primary and Secondary tranches only determines the priority in submitting the proposal to TBU, it affects only the timing of the evaluation. All proposals are still assessed for delivery costs in the final phase of Stage 1 analysis.

C. Delivery Costs

The next phase of the Stage 1 evaluation is establishing the cost of securing network transmission service for the proposals. This process consists of two sequential analyses, one conducted by TAG and the other conducted by TBU. The TAG analysis is the detailed transmission evaluation while the TBU analysis is a formal system impact study. The DTE is an estimate by TAG of what the TBU can ultimately provide. The DTE is used as a basis for the final network service costs in the event the TBU is not able to provide the SIS results within the 90-day timeframe.

Aside from providing alternative estimates of delivery costs in the event the TBU results are delayed, the DTE also enables mitigation measures to be included with the TBU SIS requests. Mitigation measures are actions that can be taken to avoid costly transmission upgrades and are noted in the SIS request for TBU to study. These mitigation measures make transmission available through management of existing Entergy generation resources. They are discussed in detail below.

1. Detailed Transmission Evaluation

The DTE is used to develop a "Delivery Cost adder" for each proposal that reflects the cost of providing network transmission service for the duration of the proposal. These estimates are updated with the SIS. The Delivery Cost Adder reflects the estimated cost of providing network transmission service for each proposed resource. It reflects costs for network service in both the short-term (2007 and 2008) and the long term (starting summer 2009).

Estimates of Long-Term Delivery Costs. The long-term delivery costs estimates in the Delivery Cost Adder are based on the cost of securing ATC starting summer 2009. The amount of ATC in the long-term is based on load flow cases for 2009 and 2014. If there is sufficient ATC for the proposed resources in both load flow cases, then the proposed resource has no long-term delivery costs. Fifteen of the 35 proposals met these criteria and were assigned no long-term network transmission costs.

If the long-term ATC is not sufficient in either the 2009 load flow case or the 2014 load flow case, then the Delivery Cost Adder may include long-term delivery costs that reflect the costs of physical upgrades. Physical upgrades costs are determined using the TBU online facilities upgrade cost calculator which is available to bidders on the TBU OASIS. We familiarized ourselves with the upgrade calculator and do not find reason to doubt the fairness of using the estimates as a basis for physical upgrade costs.

For proposals that lacked sufficient ATC for long-term network service, allocation of some or all of the cost of a physical upgrade may be avoided if a long-term delisting option is available. ESI determined the potential options available to each proposals and bidders were invited to proposal any of their own options. Under this "mitigation" option, an existing ESI unit (or up to two existing units) may be available that if removed ("delisted") as a network resource can create ATC for the proposed unit. The existing units to be delisted cannot exceed 125 percent of the capacity of the proposed resource and must have at least as great an impact on the constrained facility as the proposed resources. On a case-by-case basis, each proposal was checked to determine whether any existing plants satisfied the delisting alterative.

When a delisting alternative applied, which was the case for 20 of the proposals, it reduced the need for physical upgrades. In ten of those cases it completely alleviated the need for physical upgrades. The delisting alternative, when it applied to a constraint, did not result in any long-term delivery costs associated with the constraint. This was based on TAG's historical experience that delisting has not prevented the delisted resource from securing alternative transmission service (i.e., imposing no additional costs on the system).

We monitored the delisting process by identifying existing plants that could potentially lead to delisting opportunities. We were satisfied the delisting criteria and process was fair and accurate.

Short-Term Delivery Costs. In addition to any long-term delivery costs, the Delivery Cost Adders may also reflect short-term delivery costs associated with acquiring short-term network service. This adder is for proposals for which the initial delivery date is prior to 2009. The availability of short-term transmission capability for network service is estimated for 2007 and 2008 using the TBU ATC analyzer. The analyzer provides ATC estimates for 18 months. However, TAG extended the estimated ATC beyond this period to include all of 2008. The 2008 estimates are based on the corresponding month from 2007, for which the ATC analyzer does provide values. This assumption will tend to provide more favorable results to all proposals and we agreed it was reasonable. If adequate short-term ATC is available for a proposal, then the proposal is assigned no short-term delivery costs and the Delivery Cost Adder reflects only the long-term delivery costs (if any).

If ATC is not available for a portion of the delivery term prior to 2009, then there may be short-term costs incurred to provide short-term network transmission service. There are three "mitigation alternatives" that can be employed to overcome the lack of short-term ATC. The first is a short-term "displacement" alternative similar to the long-term delisting alternative discussed above. Like the long-term delisting options, under the displacement alternative one of ESI's existing network resources (and potentially the combined output of two of them), is backed down to provide the necessary ATC. The existing units to be delisted cannot exceed 125 percent of the capacity of the proposed resource and must have at least as a great an impact on the constrained facility as the proposed resources. This was evaluated on a case-by-case basis. The displacement alternative applied to 12 proposals to some degree. When it applied to a proposal, it did not result in any short-term delivery costs. This was based on TAG's historical experience that displacement has not prevented the displaced resource from securing alternative transmission service (i.e., imposing no additional costs on the system). We monitored the displacement process in the same manner as we monitored the delisting process: by identifying existing plants that could potentially lead to delisting opportunities. We were satisfied that the process was fair and accurate.

The second alternative for mitigating the lack of short-term ATC is the portfolio counter-flow alternative. Under this alternative, ESI will determine whether a redispatch of its generation portfolio could produce sufficient counterflow to allow the proposed resource to operate as a network resource. The redispatched units should have sufficiently high impact on the congested facilities so that the redispatch amount does not exceed 1.5 times the capacity of the proposed resource. If this second alternative is used, the short-term delivery costs will be based on the energy cost difference between the proposal and the redispatched resources. TAG identified no instances where the portfolio management alternative was possible. TAG explained that this mitigation alterative did not apply to any proposal because of limited dispatch flexibility on peak days. In particular, on peak days, the ability of Entergy to redispatch is limited due to units that would be most effective in relieving congestion being dispatched near their operating limit. We verified that this was the case.

The third alternative for mitigating the lack of short-term ATC is the active transmission management alternative. Under this alternative, Entergy will attempt to acquire short-term transmission service supplemented by generation purchases during periods when short-term service is unavailable for the proposed resource. Eight of the 35 proposals were assigned some level of active transmission service to provide short-term ATC. The delivery cost associated with this alternative will be based on the loss of system benefits from the unit's reduced availability. The mitigation alternative was evaluated by identifying months when the ATC was not sufficient to deliver the (offered) output of the proposed resource. At times when the ATC was not sufficient, the short-term delivery costs were based on market purchases of replacement capacity and energy. The estimated cost the capacity and energy was based on the assumptions provided by the economic evaluation team, which we reviewed and found to be reasonable.

2. TBU and the System Impact Studies

TBU's estimates of the system upgrade costs that a proposal will incur are determined by the TBU in its System Impact Study. The System Impact Study reports were received by Entergy on September 9, 2006. The results of the SIS reports were not straightforward in every case. In particular, in some instances where ESI indicated a desire to use a delisting in order to provide long-term network service, the SIS reports introduced a caveat indicating that certain measures would have to be taken in 2009 in order for the delisting to remain valid after that date. In particular, the SIS report indicated that certain transmission upgrades would have to be undertaken or additional network resources would have to be added in order to avoid having to commit to maintain the network ATC for the proposed resource. In particular, the footnote read:

> [With respect to the delisting option,] facilities identified [in the study] will have to be upgraded in 2009 or additional resources sufficient to accommodate identified re-dispatch will need to be qualified as network resources.

It was not clear what was meant by this caveat or what the implications would be. Therefore, a discussion was arranged among the IMs, TBU personnel, TBU counsel, and ESI counsel to clarify the issue and determine how to proceed.

This discussion occurred on September 8, 2006 via teleconference with TBU personnel and the IMs with ESI counsel Kim Despeaux leading the discussion. During the course of the discussion, we gained a clearer understanding of what was meant by the footnote in the SIS report. In particular, according to FERC regulation, when a utility models system transfer capabilities in future years, units owned by the transmission utility must be assumed to be committed for new load growth. Accordingly, the delisted units in several instances were assumed to be committed after 2009 to meet new load growth. Therefore, the caveat indicated that upgrades would have to be undertaken to provide the delisted unit with sufficient transmission capacity or new resources would have to be added to replace it. [redacted]

In order to convey these points more clearly, TBU, in consultation with the IMs, proposed to modify the footnote which, in pertinent part, read:

> Incremental overloads are identified commencing in 2009 when the delisted resource is predicted to be needed to serve the transmission customer's projected load. To address these overloads, the transmission customer must either: (1) fund transmission upgrades to alleviate the incremental overloads; (2) commit to secure additional network resources sufficient to serve the transmission customer's load without the use of the delisted resource; or (3) acknowledge that no future transmission capability is reserved for the delisted resource to serve future load growth and that the delisted resource will not be entitled to rollover rights.

Based on this footnote, ESI developed three approaches to assessing system benefits in order to complete the Stage 1 evaluation. The first approach is termed an "Upgrade Sensitivity". In this approach, a proposal is assumed to incur transmission costs to pay for transmission upgrades to alleviate the incremental overloads associated with securing network service and no delisting alternatives are pursued. In the second approach, called the "SSRP Sensitivity", it is assumed the a future ESI System Strategic Supply Resource Plan (SSRP) will identify resources that will be adequate to meet system needs allowing the delisting, but avoiding the incremental transmission costs associated with the "Upgrade Sensitivity" approach. In a third approach, called the "Delist Sensitivity", proposals relying on a delist will incur network access costs that reflect the cost of replacing the delisted capacity at market rates.

In light of the qualified acceptance of the delisting alternatives by TBU, we believe ESI's approach is reasonable in capturing the range of costs to secure network resources for each proposal. The "Upgrade Sensitivity" would be the most costly of the three alternatives and the "SSRP Sensitivity" would be the least costly. As explained more below, ESI chose to use the "Delist Sensitivity" as the main cost indicator for the evaluation.

Network Access Costs. The network access cost each proposal incurs is the result of two values. The first is the active transmission management costs estimated in the Detailed Transmission Evaluation discussed above. The second value reflects various estimates of upgrade costs from the TBU SIS reports. The reports indicate the specific upgrades, if any, required to obtain network service.

ESI evaluated the reports and adjusted the total upgrade costs for transmission upgrades that may be rendered unnecessary as a result of another upgrade. This was the case for some proposals where a parallel line at [redacted] was proposed as an upgrade. With the addition of the parallel line, several other upgrades were not necessary because the overload on those facilities was the result of a contingent outage on [redacted]. With the addition of the parallel circuit at [redacted], an outage on one of the parallel circuits did not result in the overload on the monitored facilities and, accordingly, an upgrade was no longer necessary on them. We find this adjustment to be reasonable.

D. Modifications to RFP Evaluation

There were slight modifications to the timing of the completion of the Stage 1 evaluation. Originally, the RFP established a "Preliminary CCGT Shortlist" at the conclusion of Stage 1. It was to consist of a subset of the "candidate proposals", i.e., those proposals sent to TBU for a system impact studies (SIS). With the SIS estimates, the RFP evaluation team was to narrow down the Candidate Proposals to the Preliminary Shortlist. Subsequently, the proposals on the Preliminary Shortlist were to undergo a Stage 2 evaluation including preliminary due diligence review and more detailed economic evaluation using production cost modeling.

The evaluation procedures changed somewhat in August when ESI agreed to a request from the LPSC to expedite the evaluation. The LPSC request was to move to Stage 2 as soon practicable. In response, ESI, in consultation with the IMs, decided it would begin detailed economic evaluation sooner than was anticipated. In particular, with respect to the CCGT analysis, the production-cost modeling would be performed in Stage 1, leading to a CCGT Preliminary Shortlist that would be informed by the production-cost modeling results, not just the proposal costs. ESI announced this accelerated schedule in a letter to bidders posted on the RFP website on August 14, 2006.

E. Production-Cost Analysis

Prosym is a production-cost model that 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. It is a common and well-accepted method for measuring the production cost impact of generator dispatch and other system constraints. For the RFP evaluation, ESI uses the Prosym model to estimate the system production-costs savings of the individual proposals.

ESI estimates the production cost saving for an individual proposal by first estimating the total annual production cost of meeting load in a "base case" that reflects the Entergy's existing resources and assumptions regarding purchases in the economy energy market and future resource additions. Next, the proposed resource is included in the Entergy dispatch for each year for which it is offered and the total annual production cost is estimated and then compared to the base case production costs to estimate the annual production-cost benefit.

ESI provided a detailed list of the major Prosym assumptions. We reviewed the assumptions and have found no systematic bias. However, we identified the modeling of the economy energy market as a major area where a more detailed analysis of the assumptions was necessary. We deemed this necessary based on our own recognition of the complexity of modeling this aspect of the market and its potential effects on the economic evaluation results.

1. Economy Energy Assumptions

The main concern is the potential for the estimated economy energy market prices to be too high or too low. If prices are too high, a proposed resource will be modeled as running in too many hours and, accordingly, the benefits estimated in Prosym will be too high. If the economy energy prices are estimated too low, then the opposite occurs, the proposal will be estimated to have to small an amount of benefit.

However, because all proposals are affected by the economy energy market assumptions in a comparable manner, our concerns about the impact of the assumptions on the relative rankings of proposals are limited. Nonetheless, proposals will vary in the extent to which economy energy assumptions affect their valuation. Accordingly, our monitoring in this regard seeks to ensure a reasonable modeling of the market to avoid the impact of any significant distortions that may be caused by the assumptions.

ESI models the economy energy market using estimated supply curves for three sources of supply: TVA, Southern Company, and internal to ESI. The basis of each of these supply curves is actual generator capacity and characteristics at each of the three locations. The capacity assumed to be available for the economy energy market at each location is the unloaded capacity that exists after all regional capacity is dispatched (regardless of ownership) to meet the entire load in the most economical manner. This is modeled using a software product called MIDAS, which estimates the least-cost dispatch of existing generating units in the entire Eastern Interconnect.

Using this unloaded capacity, the economy energy curves are then developed according to the following process: For each monthly peak hour, MIDAS identifies the lowest-cost unit not dispatched within each of the three economy energy locations. This represents the lowest-cost MW available on each supply curve. Then, for each of the three regions, the remaining undispatched units are ordered from lowest-cost to highest-cost to form a supply curve which is then used to model economy energy purchases in Prosym.

We evaluated this methodology and the results it produces. We find that these results reasonably reflect the supply likely to be available in the economy energy market. In the MIDAS model, the regional dispatch is conducted from all units regardless of ownership – both utility-owned and non-utility-owned units are dispatched.[4] Therefore, the capacity left undispatched is on units with costs that are higher than the highest-cost unit dispatched. This is consistent with the results of a competitive economy energy market. Given that a portion of the units in the MIDAS dispatch reflect what would be purchases of economy energy from regional IPPs and neighboring utilities, that portion reflects a segment of the economy energy market that is cleared at the price of the lowest-cost undispatched unit. Moreover, to bring in another unit of economy energy, the price must equal the marginal cost of the lowest-cost undispatched unit.

4 The MIDAS dispatch reflects forced and planned outages.

The economy energy cost curves estimated in MIDAS will be sensitive to assumptions about additions and retirements. The current surplus capacity situation in Entergy means that estimated dispatch prices initially will be below long-run equilibrium levels. By long-run equilibrium we mean the situation where prices are just sufficient to make the entry of a new unit just profitable (i.e., recovering not just short-run (production) costs but also capital carrying costs, amortization, and other fixed costs). When capacity levels are in surplus, economy energy prices are too low for full-cost recovery. When capacity levels are in shortage, prices produce revenues in excess of the full-cost recovery.

Because of the current surplus in the Internal Entergy region, in the initial years of the economy energy market model, a regional surplus of capacity keeps prices lower than the long-run equilibrium price. In order for the market to reach equilibrium, the region must experience a combination of load growth and/or generator retirements. The MIDAS model reflects anticipated load growth but does not reflect retirements. Without assumptions about retirements, MIDAS estimates that load growth will cause supply and demand to come into balance sometime after 2030. However, ESI assumes that equilibrium will be reached at an earlier period, at 2020. Furthermore, the equilibrium path is assumed to begin in 2015. In other words, prices are assumed to follow the MIDAS prices until 2015, when prices are interpolated between the 2015 MIDAS price and the 2020 equilibrium price.

Consistent with economic theory, the 2020 long-run equilibrium price is based on the fully-allocated cost of the generating resources required to meet the next increment of load. This is reasonable because, as discussed above, in long-run equilibrium prices should provide enough revenue (but not more) to a new unit to cover both variable operating and fixed capital costs.

ESI did not provide specific assumptions about how retirements affect the long-run equilibrium. However, the formulation of the equilibrium path makes implicit some level of retirements between now and 2020. Assuming the market convergence at 2020 is the result of retirements and we sought to check the reasonableness of this assumption.

Equilibrium in 2020 is assumed to reflect a reserve margin of 15 percent. The MIDAS model (with no retirements modeled) has a reserve margin of 41 percent in 2020. This amounts to a difference in generation capacity of close to 7,000 MW. Given the resource base of approximately 40,000 MW currently in the Entergy control area, net retirements totaling 7,000 MW by 2020 appear reasonable.

Based on our analysis of the methods used to model the economy energy market, we are satisfied that it will provide reasonable estimates of a proposal's benefit. Moreover, we also sought to check the projected prices from this method with actual market prices prevailing in the region. We found the projected prices consistent with actual near-term (one year) forward bilateral contract prices.

F. Preliminary Shortlist

The basic metric for establishing the Preliminary shortlist is *net benefit,* which is estimated using Prosym estimates of production-cost savings, the estimated transmission costs for securing network service, and the as-offered costs of the proposal. A "Reference" Prosym case model was estimated for each proposal in September and served as the basis for system wide production-cost savings estimates.

Recall from the discussion above that there were three scenarios considered in estimating network access costs: The "Upgrade Sensitivity", the "SSRP Sensitivity" and a "Delist Sensitivity". Each one is based on different assumptions on how to approach the delisting alternative in light of the TBU qualified acceptance of delisting alternatives. For the "Upgrade Sensitivity" the network access costs reflect the construction costs of the proposed upgrades – no delisting is assumed. Compared to the "SSRP Sensitivity" whereby long-term delisting is feasible in all cases as the result of anticipated capacity additions under the Strategic Supply Resource Plan, the Upgrade Sensitivity will have net benefits that are at most as great as the "SSRP Sensitivity". And, indeed, in nearly one-half of the proposals the "Upgrade Sensitivity" net benefits are less. The "Delist Sensitivity" is feasible in the long-term for only some delisted units while other delisted units are indicated as necessary for native load growth in the long-term, and it is assumed Entergy will have to buy replacement capacity to accomplish the delisting. This implies the "Delist Sensitivity" will estimate net benefits that are at most as great as the "SSRP Sensitivity" and in nearly one-half of the proposals the "Delist Sensitivity" net benefits are less. About one-half of the proposals have "Delist Sensitivity" net benefits equal to the

"Upgrade Sensitivity" net benefits. Of the other one-half, they are split about evenly between higher net benefit under the "Upgrade Sensitivity" and higher net benefits under the "Delist Sensitivity".

Figure 3 shows the economic ranking of each proposal under each of the three sensitivities sorted by the "Delist Sensitivity" net benefits.

Figure 3: Net Benefits of CCGT Proposals

Redacted

The figure shows each proposal represented by three vertical bars for each of the three sensitivities. We present the data sorted by the Delist Sensitivity because we agree with ESI's conclusion that the Delist Sensitivity most accurately reflects the choice that would be made in securing network service for a resource. In other words, if the delisting option is available for a resource, it would be pursued. And if the delisting was conditionally approved by TBU (i.e., that is feasible only if other resources are added to meet future load, as discussed above), then ESI nonetheless would proceed with the delisting and expect to procure the needed capacity to sustain the delisting on a long-term basis.

While in some instances, the net benefit of the Upgrade Sensitivity and/or the SSRP Sensitivity is somewhat different than the Delist Sensitivity, taken together, the three net benefit calculations indicate a relatively stable ranking of proposals. In particular, among the Top 17 proposals, at least two of the net benefit estimates for each proposal are higher than any of the net benefit calculations in the proposal making up the bottom 18 proposals. These 17 proposals plus the two proposals not in the top 17 for which each of the three net benefit calculations are all positive comprise the 19 proposals on the CCGT Preliminary Shortlist. We are satisfied that ESI has identified the set of proposals that are likely to provide the greatest net benefit to the Entergy system.[5] Following the determination of the Preliminary Shortlist, two bidders withdrew a total of five proposals, which reduced the preliminary shortlist to 14. These 14 proposals are shown in Figure 4.

Figure 4: Preliminary Shortlist Net Benefit Ranking

Redacted

[5] A fourth sensitivity scenario involves alternative estimates of production-cost benefits based on transmission system changes arising from the proposed network upgrades. This is called the "Interface and RMR Sensitivity". This sensitivity is only applicable in a minority of the proposals because for most proposals, there is either no upgrade associated with securing network service or the upgrade does not affect interface or RMR constraints. In these cases when there are no upgrade impacts, the underlying transmission assumptions in Prosym are not changed as a result of the transmission upgrade. Therefore no additional system fuel benefit would result and the reference Prosym case results are adequate. The RMR and Interface sensitivity did not result in a significant change in any of the proposal to which it applied and, hence the results are not discussed further herein.

IV. STAGE 2 EVALUATION

In the original RFP, the Stage 2 evaluation was to assess each proposal on the preliminary shortlist in more detail. This included conducting a more detailed economic evaluation of each proposal, initiating of preliminary due diligence[6], and inviting "best-and-final" offers. As explained above, the process was modified somewhat in response to the LPSC's request to accelerate the RFP process. Accordingly, the production-cost analysis that was planned for Stage 2 was conducted in Stage 1.

Therefore, the Stage 2 evaluation consists of the three main parts: (1) a revised economic based on best-and-final offers (if any); (2) additional analysis to reflect "terminal value" and "imputed debt costs"; and (3) preliminary due diligence.

In order to facilitate discussion of the individual proposals more easily among ESI personnel while concealing the actual identity when necessary, the evaluation team assigned project code names to the resources that made up the proposals on the preliminary shortlist. For ease of exposition, we will use these Project names for the remainder of this report unless context requires otherwise. Table 2 provides a list of the Project Names and identifying information about each project.

Table 2: Summary of Project Names on Preliminary Shortlists

Redacted

As the table shows, some projects have multiple proposals. In the remaining analyses, we examine individual proposals from each of the projects. Accordingly, Table 3 provides names

6 The term "preliminary due diligence" is used to distinguish this process from the "comprehensive due diligence" conducted after the completion of Stage 2 when final proposal selections execute a Letter of Intent (LOI) and enter negotiations toward a "Definitive Agreement".

and details of each of the individual proposals. In the cases where the project is associated with only one proposal the proposal name is simply the project name.

Table 3: Proposal Descriptions

Redacted

A. Best and Final Offers

RFP participants whose proposals were on the Preliminary Shortlist were given the opportunity to make best-and-final offers at the beginning of Stage 2. As a result, ESI could re-evaluate the proposals, including estimating new production-cost savings. While new production-cost savings estimates were anticipated as a result of the best-and-final offers, at this stage ESI decided to re-evaluate production-cost savings for all Stage 2 proposals as a result of a change in the Louisiana fuel tax that was to go in effect in 2009. The tax was to decrease from 3.3 percent to 1 percent. It was anticipated that this change would have the effect of increasing the net benefits for Louisiana generators, which included all but the [redacted] project. Accordingly, in conjunction with the best-and-final offers, ESI conducted new Prosym analysis for all proposals on the preliminary short-list to incorporate both the fuel tax change and any changes associated with the best-and-final offers.

Most of the RFP participants responded to the opportunity to make best-and-final offers. In four cases, the modified offers had an appreciable affect on the economic evaluation. These were changes to [redacted].

In the case of [redacted], the supplier offered to retain its existing proposal, but reduced the quantity offered also offer to one-half of the capacity quantity initially offered. This resulted in an entirely new evaluation [redacted]

In the case of [redacted], the best-and-final offer indicated a 9-month delay in the project start date, which would tend to decrease the net benefit. In the end, however, the fuel tax benefit outweighed this decline.

In the case of [redacted], the offer was clarified that the unit's put rights associated with its QF status would be retained. It was anticipated that this would result in a decrease in the project's economic value. In the final analysis, however, the fuel tax benefit dominated this "put" requirement.

In the case of [redacted], the proposal was changed to include an additional [redacted]. (We will continue to refer to it as the [redacted] for sake of continuity of the presentation). It was anticipated that the additional capacity would increase the net benefit on top of the net benefit from the fuel tax change.

Table 4 shows the summary of the net benefits of the best-and-final offers in comparison to the preliminary shortlist net benefits.

Table 4: Change in Net Benefit from Best-and Final Offers

Redacted

As the table shows, all units in Louisiana (which includes all proposals except [redacted]) exhibited an increase in net benefits as the result of the favorable change in the Louisiana fuel tax. We monitored the adjustments to these proposals and determined that the adjustments were properly implemented and, accordingly, we find the results reasonable.

B. Further Economic Evaluation

In addition to the net benefits from Stage 1 (adjusted for the best-and-final offers), two other values are calculated for each proposal:

- "terminal value" -- indicates the value to ESI beyond the planning horizon over which the proposal are evaluated, and
- "imputed debt costs" -- reflect the incremental finance cost to ESI from entering purchase power agreements.

1. Terminal Value

The terminal value is the residual value to the Entergy system that the proposal can provide beyond the "evaluation horizon" identified in the RFP. By evaluation horizon, we mean the period over which benefits are measured for purposes of estimating net benefits. For the CCGT proposals this is 30 years. These benefits can accrue beyond the evaluation horizon for both PPAs and for acquisition. For PPAs, these can accrue through options to extend the agreement beyond the evaluation horizon. For acquisitions, the terminal value is associated with Entergy owning the plant beyond the evaluation horizon.

We refer to the period beyond the evaluation horizon for which some terminal value may be earned by a proposal as the *terminal value horizon*. The terminal value horizon is 15 years: 2027-2041.

a. Terminal Value Horizon Revenues

The terminal value analysis uses the estimated capacity and energy prices for each year of the terminal value horizon and assumes a proposal can earn these prices if Entergy continues to retain rights to the capacity and energy into the terminal value horizon, either through ownership or options.

The estimated capacity and energy prices in the terminal value horizon are based on ESI's "Equilibrium Power Analysis". The Equilibrium Power Analysis is a spreadsheet model developed by ESI that estimates the capacity and energy prices in future years based on underlying capital and operating costs of generation units. These underlying costs are based on 2005 values that are projected onto future years using an assumed inflation rate. Three technologies are assumed to operate: pulverized coal ("PC"); combined cycle gas turbine (CCGT), and a combustion turbine ("CT").

The level of capacity installed and the volume of energy each technology produces is determined by a breakeven analysis. A break-even equilibrium is assumed to be achieved when each unit earns a per-MW capacity price equal to the per-MW annual fixed cost of a CT and at the same time inframarginal revenues for the CCGT and PC technology is sufficient to cover their respective annual fixed costs.

Units are assumed to earn energy revenue based on the marginal cost of the most expensive technology producing in each hour. Accordingly, a CT does not have to earn any inframarginal energy revenue to breakeven (because the annual capacity payment is equal to its fixed cost). However, a CT has to run in a sufficient amount of hours to provide inframarginal revenue to the CCGT.

Using the load shape from 2004, a necessary condition for equilibrium is that the CT runs in the highest 12 percent of all hours. This is when load is greater than 78 percent of the annual peak. This is a necessary condition because, in addition to its capacity payment, this number of hours that ensures a CCGT operating and earning a price equal to the marginal cost of a CT would earn sufficient inframarginal revenues sufficient to cover the annual fixed cost of a CCGT. This assumes that in all other hours the CCGT earns no inframarginal revenues because it is either the marginal unit setting price (at the CCGT marginal cost) or PC capacity is sufficient to meet entire load (and thus the CCGT is not operating at all).

If the CT runs in highest 12 percent of all hours, the load shape from 2004 implies that top 22 percent of the peak load is served by the CT. Accordingly, the CT comprises 22 percent of system capacity.

Using similar logic, and again using the 2004 load shape, a second necessary condition for equilibrium is that the CCGT must run in all hours when load is greater than 55 percent of the annual peak. This is to ensure the PC capacity earns sufficient inframarginal revenue. When load is greater than this level, but less than 78 percent of the annual peak, the PC capacity earns inframarginal revenue based on the running cost of the CCGT. When the load is greater than 78 percent of peak, the PC will earn inframarginal revenues based on the marginal cost of the CT. These inframarginal revenues (pus the capacity payment) are sufficient to ensure the PC covers annual fixed costs.

Because CCGT capacity must operate when load is greater than 55 percent of annual peak and CT capacity must operate when load is greater 78 percent of annual peak, CCGT capacity comprise 23 percent of total capacity (78%-55%). It follows that PC capacity comprise 55 percent of the total.

Given specific fixed operating costs of each technology, the model is able to adjust the capacity mix to ensure that CCGT and PC technologies earn just enough inframarginal revenue to cover fixed costs. (The CT fixed costs are always covered by virtue of the assumption that the capacity payment is equal to the CT fixed costs.) If CCGT fixed costs or operating costs rise, then to move back to equilibrium, CT capacity must run more often and, hence, comprise a larger share of the total capacity. Likewise, if PC fixed or operating costs rise, the CCGT and CT must operate more often, and the equilibrium mix will change.

This equilibrium case, referred to as the “market equilibrium case” is the basis for two alternative non-equilibrium cases that are also used in estimating the terminal value. These are: “tight supply”, and “over supply”.

“Tight” or Undersupplied Market. Under this scenario, the capacity price is assumed to prevail at the fixed cost of the CT that has a return on equity twice the cost of capital. Energy prices are set by the marginal cost of coal-fired generation in base load hours (i.e., as indicated above, hours when load is less than 55 percent of annual peak). In all other hours prices are set by the marginal cost of a CT. This will result in revenues that are greater than those earned in the “equilibrium” case.

Oversupplied Market. Under this scenario, the capacity price is assumed to prevail at the fixed cost of the CT that has no return on the equity portion of the investment (i.e., a 0% return on equity). Energy prices are set in base-load hours by the marginal cost of coal-fired generation and in on-peak times they are set by CCGT marginal cost (i.e., a CCGT is inframarginal in no hours). This will tend to result in revenues that are less than those earned in the “equilibrium case”

The underlying capital cost parameters are based on 2005 estimates and are established for each year in the post-planning period using an assumed inflation rate. Accordingly, there is one set of estimates for each of the three technologies for each for the three market conditions. This is shown in Table 5.

Table 5: Summary of Capacity and Energy Prices in Terminal Value Analysis

		Equilibrium	"Over Supply" Market	"Tight" Market
Energy Price	\$2005/MWh	37.80	34.06	53.64
Capacity Price	\$2005/kW-yr	51.64	38.67	64.62
All-in Price	\$2005/MWh	47.19	41.09	65.39

b. Weighted Average Revenues

If eligible under the terms of its agreement, a CCGT proposal will be credited the capacity and energy revenues estimated from the equilibrium model beginning in 2027. The values in Table 5 for a CCGT proposal will be inflated at a rate of 2.5 percent for 2006 and at 2 percent for each year thereafter.

In any given year in the terminal value horizon, the energy and capacity price that prevails is the probability-weighted average of the three scenarios. Hence, if there is an equal probability that any of the three scenarios arise, then the capacity and energy price that is assumed to prevail is a simple average of the three outcomes.

The probability that an outcome occurs in a given year is specified by a probability "tree" that assumes the 15-year terminal value horizon is divided into three equal-sized periods. The (weighted average) market outcomes are assumed to prevail for the duration of each period. In the first period, the probability of a "tight" market is 20 percent, the probability of an "equilibrium" market is 50 percent and the probability of an "oversupply" market is 30 percent.

The probabilities then "branch out" from these three outcomes to produce 9 possible outcomes in the middle period of the terminal value horizon. Each outcome is associated with one of the three outcomes in the first period and then one of the three outcomes in the second or middle period, for example, the outcome could be "tight" market in period one and equilibrium in period 2. The probability of a particular market outcome in period 2 is identical to and independent of the probabilities in period 1 e.g., the probability of a "tight" market in period 2 is 20 percent regardless of the outcome from period 1, etc. The probability of any given outcome is the product of the probability of the period 1 outcome times the probability of the period 2 outcome.

Period three, or the last period, follows similarly – there are 27 outcomes comprised of the 9 outcomes from period 2 matched with each of the three possible outcomes for period 3. Like the period 2, the probabilities are identical and independent of the probabilities of the previous two periods.

While these probabilities are skewed slightly toward the "over-supplied" market, the prices in Table 5 are skewed toward the "tight" market, in the sense that "tight" market prices are further in magnitude from the equilibrium prices than prices in the "over-supplied" market. This tends to bring the overall weighted outcomes closer to the "equilibrium outcome".

The actual market prices that a proposal earns in the terminal value horizon depends on these (weighted) market outcomes but also on the probability that the unit will be able to offer the energy and capacity during the terminal value horizon. Accordingly, further probabilities are calculated indicating the chances the unit is operating during any of the years of horizon. These probabilities are based on unit type and age. As the unit becomes older, the probability of operating declines. A CCGT unit has a 100 percent expectation to operate until after age 30. Starting at age 31, the unit's probability of operating declines each year by 6.3 percentage points until at age 45, the probability of operating is 0 percent. We find this approach to estimating operating life to be reasonable.

Table 6 shows the summary of the Estimates from the Terminal Value analysis.

Table 6: Summary of Results of Terminal Value Analysis

Redacted

The Table shows the terminal value estimate expressed in $/kW-yr of the original capacity proposed. The chart also shows three key factors that affect the calculations. These three factors are (1) the number of years in which the proposal operates in the terminal value horizon; (2) the portion of proposed capacity that is offered during the terminal value horizon (some proposals only offer an option on a portion of the original proposal); and (3) the levelized option premium to be paid during the terminal value horizon expressed in $/kW-yr of the original capacity proposed.

As the table shows, and as logic would suggest, the terminal value is generally correlated with the terminal value horizon of the individual proposal, i.e., the longer the proposal is available to provide benefits in the terminal value horizon, the higher the terminal value benefit. Some PPA proposals that extend into the terminal-value horizon have associated option premiums that can substantially off-set economic benefits.

Finally, the terminal value provides significant economic benefits to only [redacted]. The [redacted] proposal was ultimately withdrawn prior to completing the Stage 2 evaluation. Therefore, [redacted] is the only project that gains significantly from consideration of the terminal value benefit.

c. Reasonableness of Terminal Value

The estimated prices from the equilibrium power analysis are the critical component of the terminal value. Lower prices lead to directly lower terminal values and higher prices lead to higher terminal values. There are two critical assumptions in the model that will impact the level of results. The first assumption is the underlying fixed generation costs. ESI assumes the following annual fixed costs: CT -- $51/kW-yr; CCGT -- $68/kW-yr; Base Load Coal -- $210/kW-yr. The second crucial assumption involves the “probability tree” that determines the weighted average market conditions in any given year.

In order to assess the sensitivity of the model to these assumptions we established lower-bound and upper-bound values. The lower bound is calculated using the ESI assumptions with respect to underlying generation costs but uses the assumption that the market is oversupplied in all years of the terminal value horizon. The upper bound is calculated using capital costs that are 25 percent higher than the ESI costs. We judged these higher capital costs to more accurately reflect the recent market. In addition to the higher capital costs, the upper bound is also based on the assumption that the market is always under-supplied in the terminal value horizon.

Table 7 shows the result of this sensitivity analysis.

Table 7: Terminal Value Sensitivities

Redacted

The sensitivities provide a wide range of values which will provide a basis for assessing the overall impact of the terminal value on the Stage 2 evaluation, as discussed below.

2. Imputed Debt

The imputed debt issue arises from the treatment of PPA costs by the credit rating agencies. The agencies provide grades on corporate debt, like Entergy's, based on a range of financial indicators. Among them is the nature of the company's debt and other obligations. According to the Standard & Poor's ratings guidelines, a PPA is considered to be a debt at 50 percent of the PPA 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 will increase. Because a credit rating will decline when debt increases, initiating a PPA will decrease Entergy's credit rating and, consequently, its cost of capital. In order to reflect this in the RPF 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 (as measured by the return on equity) associated with Entergy issuing equity in order to maintain the same capital structure and, thus, the same credit rating.

The analysis is straightforward: one-half of the levelized PPA capacity payment (per kW-yr) is treated as an incremental debt to Entergy's capital structure. Because the assumed debt-to-equity ratio is 50 percent, any incremental debt (imputed debt) would be off-set by a 1:1 issuance of equity. If the debt-to-equity ratio was lower, then more equity would have to be issued to keep the debt-to-equity ratio constant. The cost to issuing the equity is the return on equity, which is assumed to be 11 percent. Accordingly, the imputed debt cost for a proposal is provided by the formula:

(*Levelized Capacity Charge*)x(*portion treated as debt*)x(1-*debt-to-equity ratio*)x(*cost of capital*).

Table 8 shows the summary of the imputed debt analysis.

Table 8: Estimates of Imputed Debt

Redacted

The imputed debt cost as indicated by the formula from which it is derived, and as shown in the Table, is directly related to the size of the PPA capacity charge. In fact, it is exactly [redacted] percent of the capacity charge. Consequently, all PPA capacity charges will be [redacted] percent higher when reflecting the imputed debt costs.

C. Preliminary Stage 2 Rankings

In this section we examine the overall impact of the best-and-final offers together with the Terminal value and imputed Debt analysis. Table 9 shows the best-and-final offers including adjustments for terminal value and imputed debt.

Table 9: CCGT Proposals Net Benefits with Terminal Value and Imputed Debt

Redacted

The results in the table are sorted by Original Best-and-Final Levelized Net Benefit so that the impact of the additional terminal value and imputed debt analyses could be more easily illustrated. The table shows three measures of total levelized net benefit. One measure uses the ESI's estimate of terminal value and two measures use the alternative estimates of terminal value introduced above – the upper bound or "High Terminal Value" and a lower bound or "Low Terminal value".

Relative to the Original Best-and-Final Levelized Net Benefit measure, which excludes terminal value and imputed debt costs, the rankings when including these additional values are relatively stable. The most significant difference is the benefit of the terminal value to the [redacted] Accounting for the terminal value estimates causes the [redacted] to move ahead of [redacted]. Furthermore, in two instances (*viz.*, the ESI-Terminal-Value case and the High-Terminal-Value Case), it moves ahead of the least beneficial [redacted] proposal. However, as indicated above, the [redacted] proposal was withdrawn in February 2007.

We judge the assumptions underlying the terminal value analysis to be reasonable. Additionally, our calculation of the lower- and upper-bounds provides additional economic values from which to judge the impact. Terminal value is an important aspect of evaluating the economics of each proposal and we find the application of the analysis to be fair and impartial. Accordingly, the economic values in Table 9 provide a reliable basis form which to make decisions concerning the economic benefits of each proposal. These results are used in making the final determination of the Stage 2 selections in subsection IV.E, below.

D. Preliminary Due Diligence

In addition to the economic rankings from the previous subsection, the Stage 2 selections are also based on a preliminary due diligence review. The preliminary due diligence review was organized around four major subject matter areas: (1) Operations; (2) Fuel Supply; (3) Transmission; and (4) Environmental. Subject matter experts were designated for each area and instructed to undertake a variety of activities related to the proposal and to report to the evaluation team. The subject matter experts evaluated information about individual proposals primarily from plant site visits and written responses from bidders to ESI's clarifying questions.

For each of the subject areas, the evaluation team constructed "scorecards" which translated the qualitative evaluation of each subject matter area into a quantitative "score". This quantification was extremely helpful in tracking the due diligence process and, consequently, helpful in undertaking our monitoring. Each of the subject areas were divided into focus areas and were given weights as follows: Operations 25 percent; Fuel 20 percent; Commercial 20 percent; Transmission 20 percent; Counterparty 10 percent and Environmental 5 percent.

Assigning weights to the focus areas necessarily involved the judgment of the evaluation team based on the alternative objectives and development issues and risks associated with the proposals. The most critical areas (e.g., the operational characteristics) should be given the greatest weight. The other areas appear to be reasonably positioned relative to one another in the weightings. Therefore, we find the proposed weightings to be reasonable.

Each focus area was refined into a number of sub areas. This refinement along with the weightings of each focus area is shown in Table 10.

Table 10: Preliminary Due Diligence Focus Areas

Focus Area	Weighting	Focus Area	Weighting
Operations	25%	Commercial	20%
Fit with Functional Objectives and Products		Product Delivery Term	
Overall Status & Condition of Major Equipment		Deviation from Key Proposal Guidelines	
Key Plant Personnel Experience/Knowledge		Additional Approvals Required	
Operational Control/Governance		Financial Guarantees for Non-Performance	
AGC Capability			
Flexibility of Effective Operating Range		Transmission	20%
Status of Any Equipment Service Agreements		Transmission Region Relative to Need	
Difficulty in Structuring Maintenance Strategy		Magnitude of Unavoidable Upgrade Costs	
Availability of Spare Parts		Electrical Metering/GIA	
Issues Associated with Common Facilities		Success in Obtaining Short-term Transmission Service	
		Control Area	
Fuel	20%		
Gas Supply Rating		Counterparty	10%
Gas Pressure Rating		Business Model Fit as Long-term Supplier	
Swing Capability Rating		Entity Credit Rating	
Availability of Regional Gas Storage			
Pipeline Interconnection		Environmental	5%
Type of Transportation Available (Firm/IT)		Status of Critical Permits	
Fuel Metering for Allocation to Power Blocks		Operating Restrictions/Concerns	

The preliminary due diligence scoring system was based on a score for each of the sub areas. The evaluation team established criteria for each sub area that resulted in a score of 1, 5, or 10, depending on the proposals specific characteristics. A score of 1 typically meant the project failed in this area or that significant concerns exist. A score of 5 typically meant that the project displayed adequate or normal quality or only minimal concerns. A score of 10 indicated the project exceeded normal requirements or that it met the highest possible standards. An example can help to illustrate. Under the Operations category, one sub area is “Plant Personnel Experience” A proposal was given a score of 1 in this sub area if the “Key plant personnel have limited experience and/or exhibited limited knowledge of plant and operations”. It was given a score of 5 if “Key plant personnel have normal experience and/or exhibited acceptable knowledge of plant and operations”. It scored a 10 if “Key plant personnel have significant experience and/or exhibited strong knowledge of plant and operations”.

The simple average score of the individual sub areas established the score for the entire Focus Area. Table 11 summarizes the score results by focus area.

Table 11: Summary of Preliminary Due Diligence Scores

Redacted

The weighted average scores were within a relatively narrow range – between 5.5 and 6.5 and all projects had average scores above 5. As discussed above, score of 5 indicates an adequate or normal quality with respect to the indicators of interest. While an overall average close to 5 would appear to indicate an overall adequate due diligence review, the overall average can mask deficiencies for individual proposals in some areas. For example, ESI concluded that the [redacted] project could not meet the operational requirement of load-following. Therefore, while an overall average or adequate score may indicate that problems do not arise in multiple due diligence categories, individual categories may still indicate significant problems.

The due diligence review assesses the non-quantifiable risks and other factors that are important in considering the value of a project. It provides background for the final selection in light of the economic evaluation. A project with a high economic score (expressed as net benefit), must also have an adequate due diligence score. Otherwise, the project may be unable to deliver the economic benefit or it may deliver with excessive risks. Accordingly, the due diligence review can be thought of as preventing high-risk or low-quality projects from being selected based economics alone.

E. Stage 2 Selections

As discussed above, both the net benefit calculations and the due diligence inform the final Stage 2 selection. Absent due diligence findings that undercut the economic evaluation, it is reasonable to use the net benefit from the economic evaluation as the overall indicator of a project's rank in making the final selection.

As Table 9 in the previous subsection indicates, [redacted] had economic benefits that were significantly higher than the other proposals. The closest competing proposal was the [redacted] proposal which was withdrawn in February. Excluding Wildcat, the next-highest ranked proposal was project [redacted] with a net benefit of [redacted]compared to the [redacted] proposals whose net benefit ranged between [redacted]. Additionally, [redacted] exhibited the highest net benefits even when the terminal value and imputed debt costs were excluded. Finally, the due diligence review of [redacted] did not indicate significant issues. Accordingly, the [redacted] proposals were selected for further negotiations and final comprehensive due diligence.

The other proposals were notified that they would no longer be considered in the RFP process. While these rejected proposals had significantly lower net benefits compared to [redacted], ESI also noted aspects of the [redacted]proposals that, in addition to the economic analysis, were adverse from the perspective of ESI's resource planning. With respect to [redacted], ESI indicated that the resource could not be dispatched or operated in a load following manner. With respect to [redacted], ESI indicated that the resource was only partially completed and would "impose substantial completion risk" which, according to ESI are risks that are "exacerbated by the limited guarantees proposed by [the bidder]". We believe the economic results alone justify the selection of [redacted]. However, our monitoring of the due diligence review and results also gives us no reason to doubt ESI's additional conclusions with regard to [redacted].

ESI proceeded with negotiation and further due diligence with [redacted]. In August 2007, ESI entered into an agreement to acquire the entire capacity of the [redacted] project. We believe this final agreement was the result of a fair evaluation process that adhered closely to the requirement of the RFP.