BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 040206-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S PETITION TO DETERMINE NEED FOR TURKEY POINT UNIT 5 ELECTRICAL POWER PLANT

DIRECT TESTIMONY & EXHIBIT OF:

ALAN S. TAYLOR

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

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DOCKET NO. 04_____-EI

March 8, 2004

Q. Please state your name and business address.

A. My name is Alan S. Taylor, and my business address is 5511 Northfork Court, Boulder, Colorado, 80301.

Q. By whom are you employed and what position do you hold?

A. I am president of Sedway Consulting, Inc.

Q. Please describe your duties and responsibilities in that position.

A. I perform consulting engagements in which I assist utilities, regulators, and customers with the challenges that they may face in today's dynamic electricity marketplace. My area of specialization is in the economic and financial analysis of power supply options.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Science Degree in energy engineering from the Massachusetts Institute of Technology and a Masters Degree in Business Administration from the Haas School of Business at the University of

California, Berkeley, where I specialized in finance and graduated valedictorian.

I have worked in the utility planning and operations area for 18 years, predominantly as a consultant specializing in integrated resource planning, competitive bidding analysis, utility industry restructuring, market price forecasting, and asset valuation. I have testified before state commissions in proceedings involving resource solicitations, environmental surcharges, and fuel adjustment clauses.

I began my career at Baltimore Gas & Electric Company, where I performed efficiency and environmental compliance testing on the utility system's power plants. I subsequently worked for five years as a senior consultant at Energy Management Associates (EMA, now New Energy Associates), training and assisting over two dozen utilities in their use of EMA's operational and strategic planning models, PROMOD III and PROSCREEN II. During my graduate studies, I was employed by Pacific Gas & Electric Company (PG&E), where I analyzed the utility's proposed demand-side management (DSM) incentive ratemaking mechanism, and by Lawrence Berkeley Laboratory (LBL), where I evaluated utility regulatory policies surrounding the development of brownfield generation sites.

Subsequently, I worked at PHB Hagler Bailly (and its predecessor firms) for ten years, serving as a vice president in the firm's Global Economic Business Services practice and as a senior member of the Wholesale Energy Markets practice of PA Consulting Group, when that firm acquired PHB Hagler Bailly in 2000. In 2001, I founded Sedway Consulting, Inc. and have continued to specialize in economic analyses associated with electricity wholesale markets.

Q. What is the purpose of your testimony?

A. I was retained to assist Florida Power & Light (FPL) in conducting its solicitation for competitive power supplies. The purpose of my testimony is to describe my role as an independent evaluator and present my findings. I reviewed FPL's solicitation process and performed a parallel and independent economic evaluation of FPL's Next Planned Generating Unit (NPGU), FPL's alternative generating option (a set of four combustion turbines located at Turkey Point), and the proposals that were received by FPL. I will discuss the process and tools that I used to conduct that parallel economic evaluation. Based on the results of my independent evaluation, I concluded that the Turkey Point combined-cycle (CC) facility described in the Need Study (i.e., Turkey Point Unit 5, the Next Planned Generating Unit) is the least-cost alternative to meet FPL's resource needs for 2007.

Q. Are you sponsoring an exhibit in this case?

A. Yes. It consists of the following documents:

Document AST-1, Resume of Alan S. Taylor

Document AST-2, Sedway Consulting's Independent Evaluation Report.

Q. Please describe the role you performed as an independent evaluator in FPL's solicitation.

A. I reviewed FPL's 2003 Ten-Year Site Plan and participated in the development of the utility's 2003 Request for Proposals (RFP). I assisted FPL with a review of its modeling approaches pertaining to its use of the Electric Generation Expansion and Analysis System (EGEAS) model, originally developed by the Electric Power Research Institute. Before receiving the proposals, I requested that FPL run EGEAS and provide results that I could use to calibrate Sedway Consulting's proposal evaluation model. I attended the opening of the proposals on October 24, 2003, reviewed and retained one copy of each submitted proposal, and evaluated the economic/pricing information from each proposal. FPL conferred with me on a number of issues relating to proposal RFP-noncompliance decisions, interpretation of proposal information, clarification requests, and economic evaluation assumptions. As the evaluation progressed, FPL and I discussed appropriate modeling assumptions in both evaluation tools (which I discuss later in my testimony). Using Sedway Consulting's Response Surface Model (RSM), I developed rankings of all of the proposals. Also, with the RSM results, I developed portfolios of resources and assessed the overall costs of such portfolios. I reviewed FPL's EGEAS runs to confirm consistency of assumptions and reasonableness of results, and I documented the entire process in an independent evaluation report (Document AST-2).

Q. You stated that you were involved in the development of the RFP. What did your involvement entail?

A. As the independent evaluator, I reviewed draft versions of the document, participated in several meetings (either telephonic or in person), and was given the opportunity to provide my input and suggestions for improving the RFP.

Q. Do you believe that FPL's RFP was a reasonable document for soliciting proposals?

A. Yes. As one who has developed over a dozen such utility resource RFPs, I believe that FPL's RFP struck a good balance between being sufficiently detailed without being overly burdensome on the respondent. With its RFP, FPL attached a draft power purchase agreement (PPA) that provided the proposers with a clear understanding of the general business arrangement that FPL contemplated.

Q. You mentioned that you were involved in a review of FPL's EGEAS modeling approaches. What did that entail?

A. FPL wished to ensure that it was using EGEAS in the best fashion for the evaluation of potential new resources. As a result of its last solicitation, FPL decided to explore refinements of its EGEAS evaluation methods. FPL had acquired a newer version of EGEAS that was PC-based and appeared to offer faster execution times. Thus, there was the possibility that FPL might be able to increase the level of evaluation detail in its modeling approaches if such changes did not also unduly increase the model's execution time. I participated in the review of modeling results and execution times associated with different approaches.

Q. What types of modeling refinements were implemented?

A. Two issues were implemented and thus represent different modeling approaches relative to those that were used in FPL's previous solicitation. The first issue involved enhanced unit-segment modeling; the second involved the use of monthly dispatch.

Q. Please discuss the findings and conclusions relating to the enhanced unit-segment modeling.

A. The enhanced unit-segment modeling issue involved the way in which resources with multiple operating modes were represented in EGEAS. For example, many new combined cycle resources have three operating modes or distinct "slices" of capacity – base combined-cycle capacity (which is the majority of such plants' capacity), duct-fired capacity (for peaking needs), and peak-firing capacity (also for peaking needs but used less frequently than duct-fired capacity). Previously, these three slices of capacity had been modeled in EGEAS as three separate units. This could lead to some confusion when one reviewed the EGEAS generating unit output reports and saw fragments of the same plants in different parts of the report. It also seemed to result in greater model execution time and more limited optimization flexibility than when the three segments were modeled as a single unit. EGEAS has the capability of representing distinct operating modes, with separate heat rates, forced outage rates, and capacities for each segment. In effect, virtually all of the information that could be defined under the old methodology for the different operating modes could be represented in EGEAS as a triple-segment unit – thereby reducing model execution time, increasing optimization flexibility, reducing potential output report confusion, and slightly improving the forced outage representation of the operating modes. I concurred with FPL's decision to implement this multi-segment modeling in EGEAS for all resources (FPL and outside proposals) that involved more than one operating mode.

Q. **Please discuss the findings and conclusions relating to the monthly dispatch issue.**

A. In FPL's last solicitation analysis, EGEAS had been used in an annual dispatch mode. Thus, for each evaluated portfolio, the model estimated FPL's total system production costs for each year of the evaluation in a single annual dispatch estimation process. EGEAS also has the capability of performing monthly dispatches – in fact, separate on-peak and off-peak dispatches for each month, thereby yielding 24 dispatch results for each year. Particularly in combination with the multi-segment unit modeling approach discussed above, it was found that this monthly dispatch feature could be implemented without unduly increasing model execution time. Adopting this monthly execution approach allowed more detailed representation of total generating unit summer and winter capacity and monthly natural gas prices, which can vary significantly among different months of the year. Thus, it was decided that the monthly modeling might produce enhanced evaluation results that would justify the increased model execution time. I concurred with FPL's decision to implement the monthly dispatch feature in EGEAS.

Q. Do you believe that FPL's evaluation process was conducted fairly?

A. Yes. The outside proposals, FPL's Next Planned Generating Unit, and FPL's Turkey Point combustion turbine (CT) alternative generating option were evaluated on an equal footing, with consistent assumptions applied to all resource options.

Q. Please describe Sedway Consulting's RSM model and its use in FPL's solicitation.

A. The RSM is a spreadsheet model that I have used in solicitations around the country. It is a relatively straightforward tool that allows one to independently assess the cost impacts of different generating or purchase resources for a utility's supply portfolio. Most of the evaluation analytics in the RSM involve calculations that are based entirely on my input of proposal costs and characteristics. A small part of the model examines system production cost impacts and needs to be calibrated to simulate a specific utility's system. In the case of the FPL solicitation, in the weeks prior to the proposal opening, I requested that FPL execute a specific set of runs with its detailed evaluation model, EGEAS. With the results of these runs, I was able to calibrate the RSM to approximate the production cost results that EGEAS would produce in a subsequent evaluation of any proposals or self-build options that FPL might receive. Thus, I would not have to rely on FPL's modeling of a proposal; instead, I would be able to insert my own inputs into my own model and independently evaluate the economic impact of any particular proposal. In short, the RSM provides an independent assessment to help ensure against the inadvertent introduction of significant mistakes that could cause the evaluation team to reach the wrong conclusions.

Q. How is the RSM an independent analytical tool if it is based on initial EGEAS results?

A. As I noted above, most of the calculations performed by the RSM are not based on EGEAS results in any way. There are two main categories of costs that are evaluated in a resource solicitation: fixed costs and variable costs. The costs in the first category – the fixed costs of a proposal – are calculated entirely separately in the RSM, with no reliance on the EGEAS model for these calculations. The second category – variable costs – has two parts:

(1) the calculation of a resource's variable dispatch rates and, (2) the impact that a resource with such variable rates is likely to have on FPL's total system production costs. As with the fixed costs, a proposal's variable dispatch rates are calculated entirely separately in the RSM, with no basis or reliance on the EGEAS model. It is only in the final subcategory – the impact that a resource is likely to have on system production costs – that the RSM has any reliance on calibrated results from EGEAS.

Q. **Please elaborate on that area of calculations where the RSM is affected by the EGEAS calibration runs.**

A. This is the area of system production costs. These costs represent the total fuel, variable operation and maintenance (O&M), and purchased power costs that FPL incurs in serving its customers' loads. Given FPL's load forecast, the existing FPL supply portfolio (i.e., all current generating facilities and purchase power contracts), and many specific assumptions about future resources and fuel costs, EGEAS simulates the dispatch of FPL's system and forecasts total production costs for each month of each year of the study period. At the outset of the solicitation project, the RSM was populated with monthly system production cost results that were created by the EGEAS calibration runs.

Q. What did the RSM do with this production cost information?

A. Once incorporated into the RSM, the production cost information allowed the RSM to answer the question: How much money (in monthly total production costs) is FPL likely to save if it acquires a proposed resource, relative to a reference resource? The use of a reference resource simply allowed a consistent point of comparison for evaluating all proposals, FPL's Next Planned Generating Unit, and FPL's alternative generating unit. I used a reference resource with a high variable dispatch rate of $100/MWh. In fact, I could have picked any variable dispatch rate for the reference resource and obtained the same relative ranking of proposals out of the RSM. The cost of the reference resource has no impact on the relative results – it is merely a consistent reference point.

Q. Can you provide a numerical example that shows how the RSM works?

A. Certainly. Assume that a utility has a one-year resource need of 1,000 MW and must select one of the two following proposals:

	Proposal A	Proposal B
Capacity:	1,000 MW	1,000 MW
Capacity Price:	$9.00/kW-month	$5.50/kW-month
Energy Price:	$20/MWh	$50/MWh

For both proposals, the RSM has already calculated the fixed costs (and represented them in the capacity price) and the variable costs (and represented them in the energy price). Proposal A is more expensive in terms of fixed costs, but Proposal B is more expensive on an energy cost basis. The RSM calculates the final piece of the economic analysis – the different impacts on system production costs – to determine which proposal is less expensive in a total sense for the utility system as a whole.

Assume that the RSM has been calibrated and populated with the following production cost information:

For a 1,000 MW proxy resource, the utility's one-year total system production costs are:

- $2.500 billion for a $100/MWh energy price reference resource
- $2.488 billion for a $50/MWh energy price resource (Proposal B)
- $2.452 billion for a $20/MWh energy price resource (Proposal A)

Thus, the energy savings (relative to the selection of a $100/MWh reference resource) are $48 million for Proposal A with its $20/MWh energy price and $12 million for Proposal B with its $50/MWh energy price. In its proposal ranking process, the RSM converts all production cost savings into a $/kW-month equivalent value so that the savings can be deducted from the capacity price to yield a final net cost (in $/kW-month) for each proposal. Converting the energy savings in this numerical example into $/kW-month equivalent values yields the following:

$$48 million / (1,000 MW * 12 months) = $4.00/kW-month

$12 million / (1,000 MW * 12 months) = $1.00/kW-month

The RSM calculates the net cost of both proposals by subtracting the energy cost savings from the fixed costs:

	Proposal A	Proposal B
Capacity Price:	$9.00/kW-month	$5.50/kW-month
Energy Cost Savings:	$4.00/kW-month	$1.00/kW-month
Net Cost:	**$5.00/kW-month**	**$4.50/kW-month**

Proposal B is less expensive. This can be confirmed through a total cost analysis as well:

Proposal A will require total capacity payments of $108 million (= 1,000 MW x $9.00/kW-month x 12 months), and Proposal B will require $66 million (= 1,000 MW x $5.50/kW-month x 12 months). Thus, Proposal A has fixed costs that are $42 million more than Proposal B.

Proposal A will provide $36 million more in energy cost savings (= $48 million - $12 million); however, this is not enough to warrant paying $42 million more in fixed costs. Therefore, Proposal B is the less expensive alternative.

Note that the RSM is described in more detail in the independent evaluation report that is attached to my testimony as Document AST-2.

Q. **With that understanding of the RSM process, what did you do to calibrate the RSM to EGEAS?**

A. I reviewed the production cost information that FPL provided at the start of the project and confirmed that the production costs were, for the most part, exhibiting smooth, correct trends (i.e., they were increasing where they should be increasing and declining where they should be declining). Having verified that the RSM production cost values were "smooth," I was confident that inputting variable cost parameters into the model for similar proposals would yield similar production cost results. Although the RSM is not a detailed model and could not simulate FPL's production costs with EGEAS' accuracy, in the end, the independent RSM evaluation results tracked the EGEAS results quite well.

Q. Once the RSM was calibrated, what was the next step?

A. I participated in the opening of the proposal packages on October 24, 2003 and retained my own copy of each proposal. I read each proposal and participated in discussions with FPL about each proposal's compliance with the RFP's minimum requirements. Although four of the five proposals were not in compliance with the RFP's minimum requirements, it was decided that the economic evaluation should proceed with all of the received proposals. Meanwhile, FPL communicated with those who had submitted the non-compliant proposals and attempted to elicit revisions that would bring these proposals into compliance.

I incorporated pricing and operational information from each proposal into the RSM. Such information included contract commencement and expiration dates, summer and winter capacity, capacity pricing, heat rates, fuel supply assumptions, variable operations and maintenance (O&M) charges, start-up costs, expected forced outage hours, and expected planned outage hours. Most of this information was directly input into the RSM. In some cases, there were proposal assumptions or modeling issues that required some discussion with FPL and/or clarifications from the proposers.

Q. What significant proposal assumptions or modeling issues did you discuss with the FPL evaluation team during the course of the evaluation?

A. There were a number of minor points, but the major ones were addressed in discussions pertaining to the following six areas:

1. Need for a 15-year proposal for Proposal 5

2. Need for a site-specific coal price forecast for Proposal 1
3. Firm gas transportation issues
4. Temperature-dependent heat rates
5. Maximum operating times for unit operating modes
6. Winter capacities.

Q. Please describe the need for a 15-year proposal for Proposal 5.

A. Proposal 5 originally offered a tolling transaction for a 10-year period. A tolling transaction is one where FPL would be responsible for supplying the natural gas fuel. FPL's RFP stated that tolling transactions had to be for a minimum of 15 years. Thus, it was decided that FPL should contact the proposer and require a proposal that complied with the minimum term length requirements of the RFP. Indeed, the proposer provided a 15-year proposal, and that was used in the evaluation. In fact, the economics of the revised proposal were slightly better than the original 10-year proposal.

Q. Please describe the need for a site-specific coal price forecast for Proposal 1.

A. In Proposal 1, the proposer offered to develop a new coal-fired facility and charge FPL for, among other things, the actual cost of the coal consumed, for which the proposer provided annual price estimates. In the due diligence evaluation of the proposal, it was learned that the proposer was not guaranteeing these estimates, so it became necessary for FPL's fuel supply group to develop a price forecast on which the evaluation team could rely. Two forecasts were developed – one for coal-only supply and a lower one for a blend of coal and petcoke. It was the latter lower price forecast that the evaluation team chose to use. This forecast resulted in the more favorable evaluation of the resource.

Q. The third item on your list of discussion issues involved firm gas transportation. What was discussed and decided there?

A. As specified in the RFP and further described in the RFP's Addendum Two, the cost of firm gas transportation was assumed to be $0.55/mmBtu for all natural-gas-fired resources for which FPL would be responsible for acquiring fuel. Also, FPL's fuel supply group had indicated that firm gas supply only needed to be acquired for 75 percent of a combined cycle facility's annual maximum gas consumption (calculated as the product of the facility's summer base combined cycle capacity, the annual average heat rate, and 8,760 hours). For the peaking operating modes of such facilities (i.e., duct-firing capacity and peak-firing capacity) and for peaking facilities with adequate backup fuel supply arrangements, no firm gas transportation expense was required. These firm gas transportation assumptions were applied uniformly across all natural-gas-fired resources, whether self-build or outside proposals.

Q. The fourth item on your list of discussion issues involved temperature-dependent heat rates. Please describe this issue and note what was decided.

A. Particularly for natural-gas-fired facilities, generating unit heat rates (i.e., the plant's efficiency at converting heat into electricity) vary depending on outside temperatures. In the forms provided in FPL's RFP, proposers were requested to provide operating mode heat rates at 95° F (i.e., summer conditions) and 75° F (i.e., average annual conditions). For all baseload or intermediate resources and operating modes, the evaluation team used the 75° F heat rates, as such resources would likely be called on during most of the year and therefore would operate under average annual conditions. Peaking resources (e.g., combustion turbines) and peaking operating modes (e.g., combined cycle unit duct-firing and peak-firing modes) would most likely be used during summer conditions – although they occasionally may be called on to operate during cold winter peak days as well. In either case, the evaluation team decided to maintain consistency with the baseload/intermediate resources and use 75° F heat rates for all resources and operating modes. However, Sedway Consulting used the RSM to perform a sensitivity to see how using 95° F heat rates for peaking resources and operating modes would have affected the evaluation results.

Q. What were the results of the heat rate sensitivity?

A. The evaluation results were not significantly affected by the peaking heat rate assumption. For those portfolios that were closest in cost to the least-cost portfolio (i.e., the Turkey Point CC), the summer heat rates would have added about $3 million to their total costs – thereby increasing the cost difference between them and the least-cost portfolio. The detailed results are provided in the independent evaluation report that is attached to this testimony as Document AST-2.

Q. The fifth item on your list of discussion issues involved maximum operating times for unit operating modes. Please describe this issue and note what was decided.

A. In the forms provided in FPL's RFP, proposers were requested to provide any operating limitations (e.g., total maximum hours of annual operation) that may apply to their resources or to specific operating modes. The evaluation team decided to observe the EGEAS and RSM results and only make modeling modifications if the resource or operating modes appeared to violate the stated limitations. In other words, if the resource was being dispatched within its limits, no adjustments were necessary. However, if the limitations were violated in one or more years, the operating mode's expected forced outage hours (an input data item in EGEAS and the RSM) were increased to effectively curtail generation and bring the resource back in line with its stated limitations.

Q. The last item on your list of discussion issues involved winter capacities. Please describe this issue and note what was decided.

A. In checking the monthly EGEAS results, Sedway Consulting discovered that some CC units' winter capacities for specific operating modes were not exactly matching the proposed amounts. Each of the evaluated CC resources had three operating modes – base combined cycle, duct-firing, and peak-firing capabilities. For all of these resources, summer operating mode capacities were correct; total facility winter capacities were correct; but the winter capacities for the individual operating modes were slightly mis-apportioned. This minor discrepancy was because of a limitation in EGEAS that Sedway Consulting has encountered in other similar resource optimization tools and has to do with the way that data for different operating modes of a generating unit are established and modified on a monthly basis during the execution of the model. Sedway Consulting analyzed the effect of this limitation, using the RSM, and concluded that it was not significantly affecting the EGEAS evaluation results. Had FPL been able to adjust the winter capacities for each CC unit's operating modes, it would have increased the cost differential between the Turkey Point CC portfolio and all competing portfolios by approximately $4-$5 million.

Q. Once the initial modeling of each proposal had been completed, what was the next step?

A. Sedway Consulting used the RSM to develop a normalized ranking of resource options that could be combined into possible portfolios for meeting FPL's 2007 resource need. That ranking is presented in Sedway Consulting's independent evaluation report that is attached as Document AST-2.

Q. What did that ranking reveal?

A. That ranking showed that the Turkey Point CC project was the least-cost resource that could entirely meet FPL's 2007 resource need. Because the ranking was normalized (i.e., each resource's costs were divided by the resource's capacity), the ranking was not affected by the size of a facility or whether or not the facility could entirely meet FPL's resource need. It simply ranked all of the resource options on a $/kW-month basis. The Turkey Point CC came in second, behind a 50 MW offer (Proposal 1). Although Proposal 1 appeared to have a lower net levelized fixed price, it was too small to meet FPL's resource need on its own and therefore had to be combined with other resources to be considered. Also, it is important to note that Proposal 1 was ultimately deemed non-compliant with the RFP's minimum requirements and therefore could not be part of any portfolio in this RFP.

Q. Were there any other resources that ranked higher (i.e., were shown to be less expensive on a normalized basis) than the Turkey Point CC?

A. No.

Q. What was the next step in the evaluation process?

A. FPL and Sedway Consulting began looking at combinations of proposals, including combinations with FPL self-build resources, that would meet the 2007 resource need. Ultimately, we found eight discrete combinations of resources that represented reasonable portfolios that met the 2007 resource need without exceeding it by too much capacity – i.e., more than a few hundred megawatts. These eight portfolios included the single-resource portfolio of the Next Planned Generating Unit (i.e., the Turkey Point CC) and seven competing portfolios with varying compositions. Some had just individual proposed resources in them. Some had multiple proposed resources in them. Others had proposed resources combined with FPL's Turkey Point CT alternative generating option. Ultimately, all but one of these competing portfolios were set aside because the proposers of component proposals were unwilling to rectify their proposals' non-compliance with the RFP minimum requirements. However, these non-compliance issues were not settled until most of the evaluation process had been completed. Therefore, the evaluation results discussed in my testimony and provided in Sedway Consulting's independent evaluation report include the results for all eight portfolios for completeness sake.

During the evaluation process, the evaluation team compared the rankings of these eight portfolios from EGEAS and the RSM, based on core economic costs. The rankings were fairly similar. Both models indicated that the Turkey Point CC portfolio was the least-cost portfolio. Minor differences in the ranking of the competing portfolios were found to be caused by the different mechanisms that the two models use for valuing surplus portfolio capacity and filling in new capacity upon the expiration of an intermediate-term contract during the study period.

Q. You mentioned that these rankings were based on the portfolios' "core economic costs." What are those costs?

A. Those are the primary costs of the proposed transactions that are included in the production costs for the FPL system in the two models. Such costs include capacity-related charges or revenue requirements (for both 2007 resources and for future post-2007 generic resources), fuel usage and transportation costs, variable O&M charges, start-up costs, and the overall impact on other existing or future generic units' dispatch and fuel costs. In short, in EGEAS, the core economic costs are the cumulative present value of revenue requirements (CPVRR) associated with the FPL total system production costs over the study period – without any transmission-related costs or financial adjustments. In the RSM, a portfolio's core economic costs included the same analogous elements – the cumulative present value of each proposed resource's capacity-related costs and production cost savings, combined with the portfolio's overall value of surplus capacity – again, without any transmission-related costs or financial adjustments. The core economic costs were the starting point to which other portfolio-related costs were added to develop each portfolio's final total cost.

Q. What were the other costs that were added to each portfolio's core economic costs?

A. There were four transmission-related costs, a residual value calculation (used only in Sedway Consulting's analysis), and an equity adjustment calculation. The four transmission-related costs were:

1. transmission integration costs,
2. capacity-related costs associated with transmission losses,
3. energy-related costs associated with transmission losses, and
4. increased operating costs of Southeast Florida gas turbines (GTs).

Q. How were transmission integration costs factored into the evaluation?

A. Under the direction of an independent transmission consultant, FPL's transmission department analyzed each of the eight portfolios to determine what transmission integration investments might be necessary to accommodate the development and receipt of power injections from specific points of delivery. The results showed that transmission integration costs may add from $4 million to $56 million (CPVRR) to the cost of a portfolio, depending on the specific geographic configuration of the resources in each portfolio.

Q. Please describe the calculation of capacity-related costs associated with transmission losses.

A. Once FPL's transmission department and its independent transmission consultant had developed the transmission integration requirements for each portfolio, the total FPL system peak-hour transmission losses were calculated for each portfolio and for each year of the study period under the assumption that the portfolio's required transmission assets were constructed. The Turkey Point CC portfolio had the lowest 2007 system losses and was therefore selected as the reference portfolio for the calculation of additional costs for the other portfolios. Those additional costs were calculated by recognizing that the incremental peak-hour transmission losses represented lost capacity that FPL would need to replace or purchase in order to bring each portfolio back up to a level that would be comparable with the reference portfolio. The cost of this capacity was established by FPL in its RFP as $5.00/kW-month in 2009. FPL and Sedway Consulting chose to escalate the value thereafter by 1.7 percent – the escalation assumption for capacity costs used throughout the evaluation.

Q. Please describe the calculation of energy-related costs associated with transmission losses.

A. For each portfolio of resources for each year of the study period, FPL's transmission department and its independent transmission consultant developed estimates not only for FPL's peak-hour system transmission losses but also for average-hour losses. These two annual values for each portfolio were used to calculate the energy-related transmission losses that would have to be made up in each hour in order to bring each portfolio's total system generation back up to a level that would be comparable with the reference portfolio. The peak-hour transmission losses were assumed to be applicable to the highest 10 percent of the hours of a year (thus, for a total of 876 hours). The average-hour transmission losses were assumed to apply to the remaining 90 percent of the hours (i.e., 7,884 hours). Using EGEAS, FPL developed two $/MWh system marginal energy rates for each year of the analysis – one for the 10 percent highest-load hours of the year and a second for the remaining 90 percent lower-load hours of the year. The high-load marginal energy rate was multiplied by each portfolio's incremental peak-hour transmission loss and 876 hours to calculate the portfolio's annual additional marginal energy costs for the high-load hours. A similar calculation was performed for the 90 percent lower-load hours, using the marginal energy rate for the lower 90 percent of the year's hours, a portfolio's average-hour losses, and 7,884 hours. Together, these additional marginal energy costs represented the added costs of marginal generation on the FPL system that would be called on to make up for the hourly incremental energy component associated with transmission losses for each portfolio (relative to the reference portfolio).

Q. Please describe the calculation of increased operating costs associated with Southeast Florida GTs.

A. According to FPL, the southeast region of the state is becoming transmission-constrained such that GTs have or will be required to operate out of economic order to preserve system reliability. Therefore, for those portfolios that did not include sufficient generation in Southeast Florida, it was expected that FPL's existing GTs in that area would have to be dispatched more often than if all of the 2007 capacity need was met with generation sited there. For each portfolio, FPL estimated the likely additional runtime of its Southeast Florida GTs because of transmission constraints (relative to the Turkey Point CC portfolio) and the associated costs of operating those resources instead of more cost-effective generation than would have been the case had those constraints been relieved by siting the 2007 capacity in Southeast Florida.

Q. Please describe the issue of residual value.

A. The residual value concept is associated with any resource that continues to have costs or value beyond the end of the study period (i.e., beyond 2031). None of the outside power purchase proposals extended beyond the end of the study. However, the FPL Next Planned Generating Unit and the Turkey Point CT alternative generating option are likely to continue to operate beyond the

25-year time frame that formed the basis of the revenue requirements calculation for these resources. Thus, the costs of FPL's Next Planned Generating Unit and the Turkey Point CT alternative generating option were premised on FPL's customers paying for the capital costs over 25 years, but the customers will continue to enjoy the benefits of the power for operating lives that are likely to be 35 years or more. Given that, I calculated the present value of the net benefits of an additional 10 years of capacity from the Next Planned Generating Unit and the Turkey Point CT alternative generating option. I used a conservative estimate of the value of the capacity (i.e., an estimate of the market price that may be associated with capacity in that time frame) and assumed that FPL customers would continue to pay fixed O&M costs and incremental capital costs (with the latter at reduced levels) to keep the facilities running. The net benefit of the capacity was calculated as the facilities' capacity value minus the costs.

Q. Did FPL's analysis include a residual value calculation?

A. No. Therefore, I believe that the FPL analysis understated the value of portfolios that included FPL's Next Planned Generating Unit and the Turkey Point CT alternative generating option by $62 million and $34 million, respectively.

Q. Please describe the net equity adjustment and explain how it was applied to the evaluation process.

A. An equity adjustment is a cost associated with contracting for power from an outside party. Rating agencies view some portion of a utility's capacity payment obligations to a power provider as the equivalent of debt on the utility's balance sheet. If a utility does not rebalance its capital structure with additional equity, this debt equivalent can negatively impact a utility's financial ratios, influencing rating agencies to downgrade their opinion of the utility's creditworthiness and increasing the utility's cost of borrowing. Consequently, an adjustment acknowledging this incremental cost of capital must be made to all capacity purchase options in order to put them on an equal footing with self-build options. As some offsetting factors, FPL indicated in its RFP that the completion security and performance security aspects of potential PPAs may provide two mitigating elements that would reduce a purchase's equity adjustment. Thus, a net equity adjustment was calculated for each proposal to represent the additional cost to FPL and its customers of rebalancing its capital structure – net of the effects of the two mitigating factors – were FPL to contract for the power associated with each proposal. This net value was summed for all outside proposals in each portfolio and added to the portfolio's total cost.

Q. Have you seen this equity adjustment concept incorporated in other solicitations?

A. Yes, both inside and outside of Florida. Also, I believe that recent events in the electricity markets have underscored the importance of energy companies maintaining strong balance sheets. Rating agencies have become quite severe in their evaluation of energy companies' financial ratios. Thus, it was appropriate for the proposal evaluation team to incorporate into its analyses the estimated financial impact and imputed debt associated with the signing of purchase power agreements.

Q. What were the final results of the evaluation?

A. The top portfolio was the single-resource portfolio that consisted of FPL's 1,144 MW Turkey Point CC facility (i.e., Turkey Point Unit 5, the Next Planned Generating Unit). Seven alternative portfolios were initially evaluated, and all had final costs that were at least $302 million more expensive under base case assumptions. By final costs, I mean each portfolio's total costs after any and all proposal revisions associated with the proposal clarification and the best and final offer processes. I wish to note that all costs provided in my testimony and in the attached independent evaluation report are indeed final costs.

Four of the five proposals failed to comply with the RFP's minimum requirements. FPL communicated with the relevant proposers and made attempts to rectify the non-compliance issues; however, FPL was not successful, and these proposals ultimately were deemed non-compliant and set aside. Only one of the seven alternative portfolios did not include any of these non-compliant proposals. Under base case assumptions, this portfolio was found to be $323 million more expensive than the Turkey Point CC portfolio. A complete list of the evaluated portfolios is provided in Sedway Consulting's independent evaluation report (Document AST-2).

Q. What do you conclude about FPL's solicitation?

A. I conclude that the Turkey Point CC portfolio is the least-cost portfolio and concur with FPL's decision to move forward with that project. The solicitation process yielded the best results for FPL's customers while treating proposers fairly. The RFP was sufficiently detailed to provide necessary information to proposers. The economic evaluation methodology and assumptions were appropriate and unbiased, and the independent evaluation procedures provided a cross-check of FPL's proposal representation in EGEAS and confirmed FPL's EGEAS results. Finally, I conclude that the Turkey Point CC portfolio is $323 million less expensive than the only compliant portfolio under base case assumptions.

Q. Does this conclude your testimony?

A. Yes.

RESUME OF ALAN S. TAYLOR

AREAS OF QUALIFICATION

Competitive bidding resource selection, integrated resource planning, market analysis, risk assessment, and strategic planning

EMPLOYMENT HISTORY

- President, Sedway Consulting, Inc., Boulder, CO, 2001-present
- Senior Member of PA Consulting, Inc., Boulder, CO, 2001
- Vice President, Global Energy Business Sector, PHB Hagler Bailly, Inc., Boulder, CO, 2000
- From Senior Associate to Principal, Utility Services Group, Hagler Bailly Consulting, Inc., Boulder, CO, 1991-1999
- Senior Consultant, Energy Management Associates, Atlanta, GA, 1983-1988
- Internships at: Pacific Gas & Electric Company, San Francisco, CA (1990)
  Lawrence Berkeley Laboratory, Berkeley, CA (1989-1991)
  MIT Resource Extraction Laboratory, Cambridge, MA (1982)
  Baltimore Gas and Electric Company, Baltimore, MD (1980)

EDUCATION

- Walter A. Haas School of Business, University of California at Berkeley, MBA, Valedictorian, Corporate Finance, 1991
- Massachusetts Institute of Technology, BS, Energy Engineering, 1983

PROFESSIONAL EXPERIENCE

- Developed and/or reviewed dozens of requests for proposals for utility resource solicitations.
- Conducted numerous competitive bidding project evaluations for conventional generating resources, renewable facilities, and off-system power purchases.
- Assisted in contract negotiations with shortlisted bidders in utility resource solicitations.
- Testified on utility competitive bidding solicitation results, affiliate transactions, cost recovery procedures, rate case calculations, and incentive ratemaking proposals.
- Managed the development of market price forecasts of North American and European electricity markets under deregulation.
- Performed financial modeling of electric utility bankruptcy workout plans.
- Managed the technical and economic appraisal of cogeneration facilities and brownfield generation sites.
- Trained and assisted many of the nation's largest electric and gas utilities in their use of operational and strategic planning computer models.

SELECTED PROJECTS

2003 **Expert Witness in Transmission Litigation**
Client: Midwestern utility

Served as an expert witness in a transmission lawsuit in the Midwest. Mr. Taylor focused on the economic damages associated with an alleged breach of contract concerning firm electric transmission service.

2002- **Minnesota Solicitation for New Resources**
2003 Client: Northern States Power

Assisted in the evaluation of a large number of multi-option proposals for new power supplies in the 2005-2009 time frame. Mr. Taylor was the independent evaluator in two separate solicitations. He managed a team of individuals in the evaluation of responses for both Requests for Proposals (RFPs). In the first solicitation, contingent proposals were received that could serve as replacement contracts for 1,100 MW of nuclear capacity if NSP were forced to decommission its Prairie Island power plant in 2007. In the second solicitation, NSP sought approximately 1,000 MW of new supplies to supplement its existing supply portfolio. The evaluation included the review of over a dozen proposed wind projects.

2002 **Florida Revisions to Bidding Rule**
Client: Consortium of utilities

Provided the Florida Public Service Commission with recommendations concerning appropriate revisions to the state's bidding rule. Mr. Taylor participated in public workshops to provide the benefits of his extensive experience in performing competitive bidding solicitations and to convey what changes should or should not be made to Florida's existing bid rule to ensure the selection of the best resources for the state's electricity customers.

2002 **Arizona Testimony Concerning Competitive Bidding Solicitations**
Client: Harquahala Generating Company, LLC

Filed testimony before the Arizona Corporation Commission in the Generic Proceedings Concerning Electric Restructuring Issues and Associated Proceedings. Mr. Taylor's testimony provided the Commission with information about competitive bidding processes that he had seen work in other states. Also, his testimony addressed various concerns that were raised by Arizona Public Service as to the feasibility of implementing competitive bidding in Arizona.

2002 **Florida Solicitation for New Resources**
Client: Florida Power & Light

Provided independent evaluation services in Florida Power & Light's solicitation for 1,750 MW of new power supplies in the 2005-2006 time frame. Mr. Taylor performed a parallel economic evaluation to that which was undertaken by the utility. His work efforts allowed all proposal parameters to be cross-checked and corrected where necessary. Also, he provided suggestions on resource optimization modeling approaches that ensured the most comprehensive examination of thousands of potential combinations of proposals.

2001 **Wisconsin Testimony Concerning Competitive Bidding Solicitations**
Client: MidWest Independent Power Suppliers

Provided testimony in a proceeding before the Wisconsin Public Service Commission on behalf of a consortium of independent power producers. Mr. Taylor testified on the benefits and timing of a competitive bidding solicitation that Wisconsin Electric Power Company (WEPCO) should be ordered to conduct prior to the utility's development of $2.8 billion in self-build generation facilities (embodied in a WEPCO proposal called Power the Future – 2). Without the benefits of a competitive solicitation, there would be no defensible means of ensuring that the utility's customers were being offered the best, most cost-effective resources.

2001 **Regulatory Support of Commission Staff**
Client: Utah Division of Public Utilities

Assisted staff for the Utah Division of Public Utilities in the division's efforts to analyze PacifiCorp's Strategic Restructuring Proposal (SRP). Mr. Taylor's efforts were primarily focused on the area of the proposed power supply agreements that would govern the sale of power from PacifiCorp's proposed new unregulated generation company to the regulated distribution company.

2001 **Negotiation of Full-Requirements Purchase Contract**
Client: Georgia cooperative utility

Assisted in negotiation of a $2 billion power purchase contract. Mr. Taylor worked with a team of legal experts and other consultants to assist the client in negotiating a 15-year full-requirements contract with a large, national power supplier. Detailed modeling simulations were performed to compare the complex transaction to the utility's own self-build alternatives. Mr. Taylor helped investigate and negotiate detailed provisions in the power supply contract concerning ancillary services and other operational parameters.

2001 **Evaluation of Resource Proposals**
Client: North Carolina municipal utility

Reviewed responses to a utility resource solicitation and assisted the client in developing a short list of the best bidders. Mr. Taylor reviewed the results of the client's economic analysis of the proposals and provided insights on various nonprice factors related to each of the top-ranked proposals. Mr. Taylor helped the client in structuring and strategizing for the negotiation process.

2000- **Solicitation for New Resources**
2001 Client: Public Service of Colorado

Assisted in the evaluation of a large number of multi-option proposals for new power supplies in the 2002-2005 time frame. Mr. Taylor managed a team of a dozen individuals who performed economic and nonprice evaluations of conventional and renewable proposals. Mr. Taylor developed recommendations for a short list of the best resources and managed a supplemental evaluation of second-tier bidders when the client's capacity needs subsequently increased. Ultimately, over $2 billion of contracts were negotiated for over 1,700 MW of new power supplies under terms of up to 10 years. Mr. Taylor testified before the Colorado Public Utilities Commission on the processes and results of both the primary and supplemental evaluations.

1999- **Solicitation for New Resources**
2000 Client: MidAmerican Energy

Reviewed MidAmerican's solicitation for new power supplies for the 2000-2005 resource planning period. Mr. Taylor managed a team of individuals who performed an independent parallel evaluation of MidAmerican's analysis of responses to the utility's request for proposals (RFP). Mr. Taylor reviewed MidAmerican's evaluation and negotiation process and testified to the fairness and appropriateness of MidAmerican's actions. He filed testimony before the utility regulatory commissions in Iowa, Illinois, and South Dakota.

2000 **Electricity Market Assessments**
Client: various American and European clients

Helped develop electricity market prices for regional electricity markets in North America (California, New England, Arizona/New Mexico, Louisiana) and Europe (Austria, Belgium, France, Germany, and the Netherlands). Mr. Taylor worked with project teams in the U.S. and Europe to develop simulation models and databases to forecast energy and capacity prices in the deregulating power markets.

1999 **Evaluation of New Resources**
Client: Florida Power Corporation

Helped prepare the FPC's RFP for long-term supply-side resources and assisted in the independent evaluation of responses. Mr. Taylor oversaw the review of FPC's computer simulations (in PROVIEW and PROSYM) of the proposals that were received. The project team also evaluated the proposals by using a response surface model to approximate the results that might be produced in the more detailed simulations. Mr. Taylor testified before the Florida Public Service Commission concerning his assessment of FPC's solicitation and the results of the analysis.

1998 **Evaluation of New Resources**
Client: Public Service of Colorado

Assisted the evaluation of proposals for PSCo's near-term 1999 resource additions and managed the complete third party evaluation of proposals for resources in the 2000-2007 time frame. Such resources included third-party facilities and power purchases, as well as company-sponsored interruptible tariffs. Mr. Taylor assisted with the development of the request for proposals and oversaw the evaluation of all responses. He and his team monitored subsequent negotiations with shortlisted bidders. Mr. Taylor testified before the Colorado Public Utilities Commission on the fairness of the solicitation and the results of the evaluation.

1997- **Evaluation/Negotiation of Transmission Interconnection Solicitation**
1999 Client: New Century Energies

Managed a solicitation for participation in a major transmission project interconnecting Southwestern Public Service (a Texas member of the Southwest Power Pool) and Public Service of Colorado (a member of the Western Systems Coordinating Council). As the first major inter-reliability-council transmission project in the era of open access, FERC required that SPS and PSCo solicit third-party interest in participation. This project required the development of an RFP and evaluation of responses for both equity participation and long-term transmission service for over 21 alternative high-voltage AC/DC/AC transmission projects. The evaluation focused on the costs and intangible risks of different transmission alternatives relative to the benefits and savings associated with increased economy interchange, avoided future generating capacity, and reductions in single-system spinning reserve and reliability requirements.

1996- **Evaluation/Negotiation of All-Source Solicitation**
1997 Client: Southwestern Public Service

Managed the evaluation of a broad array of responses to an all-source solicitation that was issued by Southwestern Public Service (SPS). Resources in the areas of conventional supply-side generation, renewable resources, off-system transactions, DSM, and interruptible loads were proposed. The evaluation entailed scoring the proposals for a variety of price and nonprice attributes. Mr. Taylor assisted Southwestern in its negotiations with the bidders and performed the detailed evaluation of the best and final offers.

1996- **Risk Assessment for 1,000-MW Solicitation**
1997 Client: Seminole Electric Cooperative

Managed the review and assessment of risks associated with responses to a 1,000-MW solicitation that was issued by Seminole Electric Cooperative. The evaluation entailed reviewing selected proposals' financial feasibility, performance guarantees, fuel supply plans, O&M plans, project siting, dispatching flexibility, and bidder qualifications.

1997 **Analysis/Testimony Concerning Louisville Gas & Electric's Fuel Adjustment Clause**
Client: Kentucky Industrial Utility Customers

Performed a detailed examination of Louisville Gas & Electric's (LG&E) fuel adjustment clause and identified misallocated costs in the areas of transmission line losses and purchased power fuel costs. Mr. Taylor also critiqued LG&E's rate adjustment methodology and recommended closer scrutiny of costs associated with jurisdictional and non-jurisdictional sales. Mr. Taylor testified before the Kentucky Public Service Commission and presented the findings of his analysis.

1997 **Analysis/Testimony Concerning Kentucky Utilities' Fuel Adjustment Clause**
Client: Kentucky Industrial Utility Customers

Performed a detailed examination of Kentucky Utilities' fuel adjustment clause and recommended more appropriate allocations of costs among jurisdictional and non-jurisdictional customers. Particular emphasis was placed on inter-system sales (and the line losses associated with such sales), purchase power fuel costs, the correct determination of jurisdictional sales. Mr. Taylor testified before the Kentucky Public Service Commission and presented the findings of his analysis.

1995 **Development of All-Source Solicitation RFPs**
Client: Southwestern Public Service

Managed the development of five RFPs that solicited resources in the areas of conventional supply-side generation, renewable resources, off-system transactions, DSM, and interruptible loads. The RFPs were issued by SPS as part of an all-source solicitation to identify resources that may be competitive with two generation facilities that SPS intended to develop.

1995 **Environmental Compliance Analysis**
Client: Western utility

Performed a confidential detailed environmental analysis that involved executing hundreds of production simulations of the client utility's system (using PROSCREEN II) to analyze SO_2,

NO_x, and particulate reductions associated with different fuel-switching, capital investment, and retirement scenarios.

1994- **Implementation of Continuous Emission Monitoring Regulations**
1996 Clients: Various

Assisted over 80 utilities in ensuring their compliance with the CAAA's continuous emission monitoring (CEM) regulations (40 CFR Part 75). Using *75check*, a CEM quality assurance software system developed by Hagler Bailly, Inc., the project team analyzed the electronic data reports that utilities must file with the U.S. EPA on a quarterly basis. These reports contain detailed hourly emissions information for every CAAA-affected plant and serve as the foundation for the SO_2 emission allowance market.

1994 **Evaluation of Clean Air Act Compliance Plan**
Client: Kentucky Industrial Utility Customers

Performed a detailed analysis of Big Rivers Electric Corporation to determine the appropriate SO_2 emission reduction strategy that the utility should undertake to comply with the 1990 Clean Air Act Amendments (CAAA). The utility's historical operations were studied and dozens of hourly production cost simulations of Big Rivers' utility system were performed to assess the operational and economic impacts of different CAAA compliance strategies. Risk/sensitivity analyses were undertaken to determine the effects of varying assumptions of fuel prices, capital costs, and operating and maintenance costs. Mr. Taylor testified before the Kentucky Public Service Commission, endorsing the implementation of a specific incentive ratemaking methodology that would encourage the utility to minimize its compliance costs.

1994 **Fuel Procurement Audit of Columbia Gas Company**
Client: Public Utilities Commission of Ohio

Assisted in a fuel procurement audit of Columbia Gas Company in Ohio. The utility's gas transportation programs were scrutinized to ensure that full service customers were not subsidizing transportation customers. Cost allocation procedures were studied and marginal costs of service for transportation customers were examined. In addition, the audit included an investigation of how the utility calculated and monitored unaccounted-for-gas.

1994 **Development of Competitive Bidding RFP**
Client: Empire District Electric Company

Based on knowledge gained from the review of dozens of other utility RFPs, developed a combined-cycle resource RFP for Empire District Electric Company. The project team was responsible for the RFP's entire development, including the development of scoring provisions for price and nonprice project attributes.

1993 **Selection of Developer for 25 MW Wind Facility**
Client: Northern States Power

Evaluated ten bids that were received by NSP in a solicitation for the development of a 25 MW wind facility in Minnesota. The proposals were scored and ranked through a point-based evaluation system that was developed prior to the solicitation. The scoring involved an assessment of operational and financial feasibility, power purchase pricing terms, construction schedules, and community acceptance issues.

1993 **Competitive Bidding Design**
Client: Northern States Power

Assisted NSP in the utility's effort to design a generic competitive bidding RFP that could be issued for a variety of generation resources. Two dozen RFPs from other utilities were reviewed to determine the appropriate weights and mechanisms that should be used to score various project attributes.

1993 **Evaluation of 500 MW Supply-Side Solicitation**
Client: San Diego Gas & Electric

Assisted in the evaluation of 15 bids that were received from a 500 MW solicitation for power by SDG&E. The utility wanted to determine whether or not there were less expensive alternatives to the implementation of its plan to repower one of its own units. The 15 projects represented over 4,000 MW. The bids were evaluated using extensive production costing modeling, in which over 1,000 model runs were performed to evaluate each bid under a variety of scenarios.

1992- **Integration of DSM Programs into Utility IRP Filing**
1993 Client: Public Service Company of Colorado

Assisted utility in DSM modeling and IRP optimization using PROSCREEN II/PROVIEW. A data transfer system was designed to translate DSM program information from various utility departments. Simulations were performed to assess the cost-effectiveness of different demand- and supply-side options.

SELECTED PUBLICATIONS AND PRESENTATIONS

"Ancillary Services, A Market Unto Itself" Financial Times Energy Conference: Navigating the New Transmission Roadmap Under FERC Order 2000, June 2000.

"Forecasting Ancillary Service Prices," Infocast Conference: How to Buy, Sell, and Price Ancillary Services in Competitive Markets, October 1999.

"Fundamentals of Electricity Deregulation," American Association of Petroleum Geologists/Electric Power Research Institute Conference, April 1999.

"The Coal/Natural Gas Balance in a Reconfigured Utility Industry," American Bar Association Conference on Electricity Law and Regulation, February 1998.

"Asset Divestitures in the Deregulating Power Markets," Hybrid U.S. Power Market Conference, February 1998.

Modeling Renewable Energy Resources in Integrated Resource Planning, D. Logan, C. Neil, and A. Taylor, National Renewable Energy Laboratory, May 1994.

Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emission Allowances, K. Rose, M. Harunuzzaman, and A. Taylor, The National Regulatory Research Institute, December 1993.

"Risk Management Under the 1990 Clean Air Act Amendments: A Study of Emissions Allowance Reserves," Electric Power Research Institute, November 1993.

"Regulatory Accounting for Acid Rain Compliance Planning," 8th Biennial Regulatory Information Conference, September 1992.

"A Seminar on the Techniques and Approaches to Integrated Resource Planning," Hawaii Public Utilities Commission, September 1992.

"A Comparison of the Uranium and Emissions Allowance Markets," A. Taylor and M. Yokell, Electric Power Research Institute, February 1992.

"State Regulation of Utility Compliance Plans and Its Impact on the Emissions Allowance Marketplace," 103rd National Association of Regulatory Utility Commissioners Annual Convention, November 1991.

"Repowering and Site Recycling in a Competitive Environment," A. Taylor and E.P. Kahn, Lawrence Berkeley Laboratory, March 1991.

Sedway Consulting, Inc.

INDEPENDENT EVALUATION REPORT FOR FLORIDA POWER & LIGHT'S 2003 SOLICITATION FOR NEW POWER SUPPLIES

Submitted by:

Alan S. Taylor
Sedway Consulting, Inc.
Boulder, Colorado

March 8, 2004

Introduction and Background

On August 25, 2003, Florida Power & Light Company (FPL) issued a Request for Proposals (RFP) for capacity and energy to satisfy the utility's projected incremental resource need for 2007. The RFP noted that power supply proposals would compete with an FPL power plant construction option in addressing a projected capacity need of 1,066 MW. This FPL option entailed a natural-gas-fired 4-on-1 combined-cycle (CC) power plant at Turkey Point with a summer capacity rating of 1,144 MW; this resource was referred to as the Next Planned Generating Unit (NPGU).

Sedway Consulting, Inc. (Sedway Consulting) was retained to advise FPL in the economic evaluation of responses to the RFP and to provide a parallel economic evaluation of the proposals. Alan Taylor, Sedway Consulting's President and the individual who provided the primary consulting services for this project, has assisted numerous utilities around the country in similar solicitations for power supplies.

On October 24, 2003, FPL received five proposals from four power suppliers. Sedway Consulting participated in the proposal opening process and retained a copy of each proposal for its review and evaluation. In addition to the five proposed power supplies and FPL's Next Planned Generating Unit, another FPL self-build resource was considered – an alternative Turkey Point project involving four combustion turbines (CTs) with a summer capacity rating of 648 MW. This alternative Turkey Point CT project was intended to be combined with proposals from outside suppliers to meet the 1,066 MW capacity need. Table 1 provides a summary of the proposed and available resources.

Table 1
Summary of Evaluated Resources

Resource	Summer Capacity (MW)	Technology	Location*	Term/Economic Life (years)
Proposal 1	50	Coal	Homestead	25
Proposal 2	1220	CC	St. Lucie Co.	15
Proposal 3	1220	CC	St. Lucie Co.	25
Proposal 4	447	CT	DeSoto Co.	15
Proposal 5	252	CC	Vero Beach	15
FPL CC (NPGU)	1144	CC	Turkey Point	25
FPL CT Alternative Generating Unit	648	CT	Turkey Point	25

* All projects were located in Florida.

Several of the proposals included elements or conditions that failed to meet the minimum requirements of FPL's RFP. In the interest of completeness and expediency, FPL and

Sedway Consulting decided to conduct an economic evaluation of all proposals while FPL worked with the proposers of non-compliant proposals in an effort to bring those proposals into compliance with the RFP minimum requirements. Ultimately, after most of the economic evaluation effort had been completed, four of the five proposals were deemed to be non-compliant and were set aside. Proposal 4 was the only proposal that was deemed to be compliant. Such compliance issues notwithstanding, this report provides the complete results for all proposals, whether or not they were eventually deemed to comply with the RFP minimum requirements.

Although mathematically speaking there were dozens of potential resource combinations that would meet or exceed FPL's capacity need, many of such combinations would result in FPL acquiring far in excess of its 1,066 MW requirement for 2007. If a utility procures too much capacity in excess of its resource needs in a particular year, such an action may burden the utility's customers with unnecessary costs in that year. Also, such an action reduces future years' resource needs – needs that may be met more cost-effectively with resources acquired or developed in future resource solicitations or planning processes. Thus, for FPL's current solicitation, the universe of potential combinations was condensed down to eight specific portfolios.

Sedway Consulting conducted its parallel economic evaluation of the proposals by using its proprietary response surface model (RSM). The RSM is a power supply evaluation tool that can be calibrated to simulate the expected resource dispatch and resulting production costs of a specific utility's operations. Prior to the opening of the proposals, Sedway Consulting requested FPL to execute several dozen runs of its system simulation planning tool – the Electric Generation Expansion and Analysis System (EGEAS). The results of these runs were used to calibrate the RSM and allowed Sedway Consulting to evaluate the production cost impacts of all proposed resources.

This independent evaluation report documents Sedway Consulting's evaluation process and presents the results of Sedway Consulting's economic analysis. It describes the RSM, the ranking methodology that was employed, fundamental assumptions that were applied, and additional economic factors that affected the final cost of each portfolio of resources. Also, it presents the evaluation results and depicts the resource portfolios without disclosing proposers' identities or any specific proposal pricing information.

Overview of Results

Of the portfolios of power supply options that were evaluated, Sedway Consulting found that the least-cost portfolio was the single-resource portfolio that consisted of FPL's Next Planned Generating Unit – the Turkey Point CC facility with a summer capacity rating of 1,144 MW.

Sedway Consulting estimated that competing evaluated portfolios were at least \$302 million more expensive than the Turkey Point CC portfolio on a cumulative present value of revenue requirements (CPVRR) basis under base case assumptions. All CPVRR values in the evaluation have a base year of 2003. Also, all costs in this report are final costs in that they reflect any and all proposal revisions associated with the proposal clarification and the best and final offer processes.

The next lowest cost portfolio included FPL's alternative Turkey Point CT project (with 648 MW of summer capacity) and two outside proposals – both involving 15-year power purchase agreements (PPAs). One offer, Proposal 4, entailed 447 MW of peaking power from predominantly existing facilities, and the other, Proposal 5, entailed 252 MW of capacity from a new CC facility. However, ultimately, Proposal 5 was deemed to be non-compliant. Thus, this portfolio did not represent a qualifying alternative.

The only competing portfolio that included the remaining compliant proposal was the combination of FPL's alternative Turkey Point CT project and Proposal 4 and was found to be $323 million more expensive than the Turkey Point CC portfolio. Although Sedway Consulting did not officially participate in the non-economic/risk evaluation, Sedway Consulting concurs with FPL's conclusion that the competing portfolio did not offer reduced risks or other non-economic benefits that could outweigh its cost differential and warrant its selection over the Turkey Point CC portfolio.

Sedway Consulting concluded that the Turkey Point CC facility should be selected.

Evaluation Process

Sedway Consulting received the following economic information for each proposal:

- Capacity (winter and summer; base, duct-fired, and other, where applicable)
- Commencement and expiration dates of contract
- Capacity pricing, including transmission interconnection costs
- Fixed operation and maintenance (O&M) and capital replacement pricing
- Firm fuel transportation assumptions
- Fuel pricing or indexing
- Guaranteed heat rate (base, duct-fired, and other, where applicable)
- Variable O&M pricing (base, duct-fired, and other, where applicable)
- Start-up costs
- Expected forced outage and planned outage hours.

The same or analogous information was received for FPL's Turkey Point CC option and FPL's alternative CT option.

The remainder of this report section addresses the following topics:

- a description of the RSM and the ranking process that it employed,
- the use of a "filler" resource in evaluating proposed transactions that expired before the end of the study period,

- special issues concerning input assumptions, and
- the process of developing cost estimates for portfolios of resources.

RSM and Net Levelized Fixed Price Ranking

The economic information for all outside proposals and FPL's stated options was input into Sedway Consulting's RSM – a power supply evaluation tool that was calibrated to approximate the impact of each proposal on FPL's system production costs. The RSM calculated each proposal's annual fixed costs and variable dispatch costs, estimated the production cost impacts of each proposal, accounted for capacity replacement costs for all proposed contracts that expired before the end of the study period, and developed a ranking of all proposals. That ranking was based on the net levelized fixed price of each proposal, expressed in $/kW-month.

A proposal's net cost was a combination of fixed and variable cost factors. On the fixed side, the RSM calculated annual fixed costs associated with capacity payments, fixed O&M costs, incremental capital charges, firm gas transportation reservation costs, and estimated start-up costs. These annual total fixed costs were discounted and converted into an equivalent levelized fixed price, expressed in $/kW-month. This was done by taking the present value of the stream of costs and dividing it by the present value of the kW-months of capacity in the proposal.

On the variable cost side, the RSM first developed a variable dispatch charge (in $/MWh) for each proposal for each year. This charge was calculated by multiplying the proposal's heat rate by the specified annual fuel index price and adding the variable O&M charge.

The RSM then estimated FPL's system production costs for each month and each proposal by interpolating between production costs estimates that were extracted from a set of EGEAS runs. These EGEAS runs were performed at the start of the project and were used to calibrate the RSM by varying the monthly variable dispatch charge for a proxy proposal and recording the resulting FPL system production cost.

For the same capacity as the proposal under consideration, the RSM also estimated FPL's system production costs for a reference unit that had a high variable dispatch charge of $100/MWh. Thus, for each proposal, the RSM yielded estimates of the annual production cost savings that FPL would be projected to experience if the utility acquired the proposed transaction, relative to acquiring the same sized transaction but at $100/MWh. The lower a proposal's variable dispatch charge, the greater the production cost savings.

The RSM then converted these annual savings into a levelized $/kW-month value, using the same arithmetic process that was performed with the annual fixed costs. Although energy-related costs are not normally expressed this way, this conversion normalized the production cost savings (i.e., accounted for the different amounts of capacity offered by each proposal) and yielded a value that could be subtracted from the levelized fixed price. Because the purpose of the solicitation was to acquire firm capacity, this conversion process translated energy savings into a metric (i.e., a comparable standard of measurement) that was tied to the capacity that a proposal offered.

For each proposal, the RSM then subtracted the levelized production cost savings from the levelized fixed price to yield a net levelized fixed price – a value expressed in $/kW-month that embodied both the fixed costs and variable production cost impacts of a proposed resource. The proposals and FPL resources were ranked in ascending order based on this net levelized fixed price. The top-ranked proposals had the lowest net levelized fixed prices, representing those proposals with the lowest fixed costs, or the greatest production cost savings, or a good combination of both.

Filler Resource

As was mentioned earlier, the RSM accounted for the costs of replacing capacity for all proposed contracts that expired before the end of the study period (which was 2031). This was done by "filling in" for the lost capacity at the end of each proposal's term of service. This allowed for a side-by-side comparison of the value of proposals that had varying contract durations. Also, the RSM had been calibrated with EGEAS runs that assumed a proxy proposed resource would provide its capacity for the entire duration of the study period. Thus, it was necessary to continue a proposal's capacity throughout the entire period so as to maintain consistent and sufficient reserve margins. In effect, by supplementing each short-term proposal with a filler resource for the later years, the RSM was simulating what FPL would have to do when a proposed transaction expired – acquire or develop an amount of replacement capacity equal to that expired resource.

As the basis for cost assumptions for the filler resource, Sedway Consulting used the same future combined-cycle resource as FPL used in the EGEAS optimization runs. The same $/kW fixed cost assumptions (e.g., construction cost, fixed O&M costs, capital replacement charges) and variable cost assumptions (e.g., heat rates, variable O&M costs, fuel supply issues) were used in the RSM as in EGEAS. The only difference involved a methodological variation, whereby the RSM scaled the replacement capacity to exactly equal the size of the expiring proposal resource. Thus, all proposals enjoyed the benefit of being replaced at the end of their terms with a resource that exhibited the operating efficiencies and economy-of-scale benefits of a 1,144 MW combined-cycle plant. In other words, if a 400 MW proposal ended in 2021, the RSM assumed that a 400 MW combined-cycle facility replaced it in 2022; however, the construction costs for the replacement facility were not those that would typically be associated with a 400 MW combined-cycle plant, but rather, they were a prorated portion (i.e., 400/1144) of the construction costs of a large combined-cycle facility.

Depending on the "in-service date" for the filler resource, the filler's capital costs were escalated from a 2007 base-year value by 1.7 percent per annum. This escalation assumption represented FPL's estimate of how construction costs were likely to increase for its generation alternatives. Sedway Consulting decided to use this escalation value to trend the filler's annual capacity charges over time. Thus, instead of using FPL's declining revenue requirements profile for the recovery of capacity costs, Sedway Consulting used an escalating pattern that yielded the same long-term present value of revenue requirements. A traditional revenue requirements profile – as was used for calculating the annual revenue requirements for FPL's Next Planned Generating Unit – results in the highest capital charges in a project's first year. Thereafter, the capital-related charges decline. This is the opposite from what is usually seen in most power purchase proposals in power supply solicitations. Most power purchase proposals tend to have flat or escalating capacity charges, presumably reflecting expectations that general inflation will increase the costs of constructing new facilities in the future. Sedway Consulting therefore restructured the filler's profile of capacity costs to match what is generally seen in the marketplace. This meant that the filler's first year's capacity costs were the lowest, with each year thereafter escalating at 1.7 percent. Figure 1 displays the escalating capacity price profile used by Sedway Consulting as well as the traditional declining revenue requirements profile. Both profiles have the same present value.

Over the full 25 years, the restructuring of the filler's capacity costs made no difference to the present value of the facility's revenue requirements. However, in the evaluation of outside proposals that were less than 25 years in duration, it provided the most favorable basis for such proposals' evaluation. In effect, it assumed that, following the expiration of an outside proposal's term, FPL would procure replacement power supplies at a prevailing market price. In reality, if an FPL self-build resource was determined to be most cost-effective at this future decision point, the declining revenue requirements profile would present the actual annual costs that FPL's customers would likely pay.

Figure 2 depicts a comparison of the two approaches for replacing a hypothetical 15-year proposed power supply contract. The proposed contract is assumed to have a capacity charge that begins at $7/kW-month and escalates at 2 percent per annum.

Relative to the declining revenue requirements methodology, the escalating filler capacity price methodology favors the 15-year proposed power supply because it defers the most expensive years of capacity costs until beyond the end of the study period. Thus, the present value of total study-period capacity costs (i.e., power supply proposal plus filler resource) is lower under the escalating filler methodology than under the declining revenue requirements methodology. Ultimately, the use of different filler methodologies by Sedway Consulting and FPL provided added value in looking at the evaluation results from two different perspectives and ensuring that the conclusions were supported from either perspective.

Figure 1
Comparison of Capacity Price Profiles

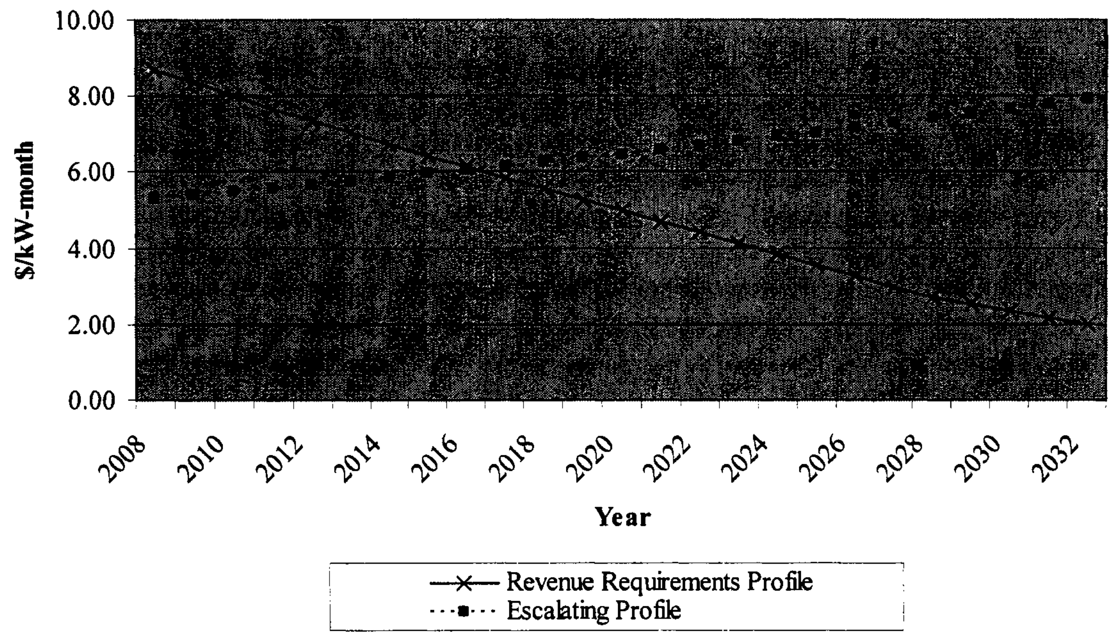
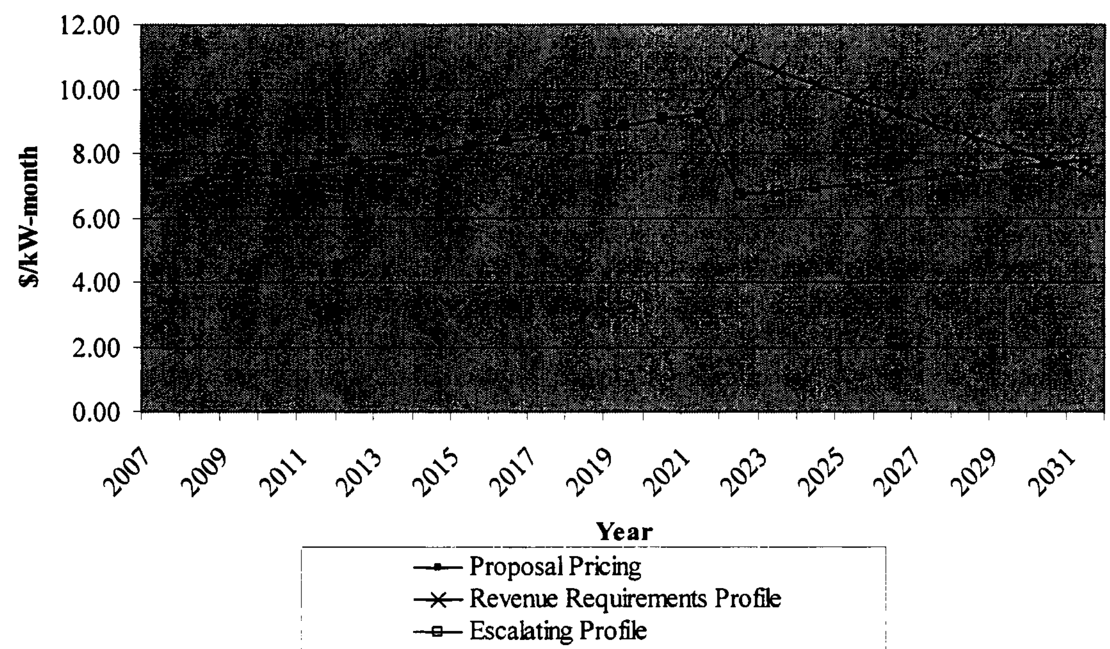


Figure 2
Comparison of Filler Capacity Price Methodologies



Input Assumptions

Most of the input assumptions for the proposals, FPL's Next Planned Generating Unit, and FPL's Turkey Point CT alternative generating option were directly input into the RSM in a straightforward fashion. This section addresses some unique considerations relating to the treatment of:

- Capacities
- Heat rates
- Firm gas transportation costs
- Maximum operating times
- Start-up costs.

Capacities: Resource capacities were requested from the proposers and FPL's Production Generation Division (PGD) under summer and winter operating conditions (95° F and 35° F, respectively). Summer capacities were assumed to be the prevailing norm during the seven months of April through October each year. Winter capacities were assumed to be the prevailing norm for November through March.

Heat rates: Operating heat rates were requested from the proposers and PGD for summer and annual average operating conditions (95° F and 75° F, respectively). The annual average heat rate was used for all operating modes for each resource. Arguably, peaking operating modes would be more likely to be dispatched during hot summer conditions than during mild average conditions. Therefore, Sedway Consulting discussed with FPL the possibility of using 95° F heat rates in the evaluation of peaking operating modes. Ultimately, it was decided to keep all resources and operating modes consistently modeled with average annual 75° F heat rates, particularly after Sedway Consulting performed a sensitivity analysis and showed that implementing 95° F heat rates for peaking operating modes did not appreciably affect the evaluation results. The results of that sensitivity are discussed below.

Firm gas transportation costs: Each CC resource's firm gas transportation costs were calculated as an annual fixed value that was based on 75 percent of the facility's maximum annual gas consumption (based on summer capacity and annual average heat rate). This quantity of gas was multiplied by a firm gas transportation charge of $0.55/mmBtu. Firm gas transportation was deemed not to be a requirement for conventional peaking, duct-fired, or peak-fired portions of a proposed facility if a resource had a sufficient backup distillate oil supply.

Maximum operating times: In instances where resources or specific operating modes of resources had annual run-time limitations, Sedway Consulting reviewed the predicted annual utilization of such resources in the RSM. If the predicted utilization was greater than the operating limitations, the resource's expected number of forced outage hours were increased to bring the predicted utilization down to the required limitation.

Start-up costs: The annual costs for starting up facilities (either outside proposers' or FPL options) were premised on FPL's assumption of six starts/year for most facilities. FPL determined that this was an appropriate number of starts for both intermediate/baseload and very-high-dispatch-cost peaking proposals. For standard peaking resources, FPL assumed 100 starts/year. The start-up costs were incorporated into the RSM as annual fixed costs.

Portfolio Development and Cost Computation

The RSM provided a ranking of all outside proposals, FPL's Next Planned Generating Unit, and FPL's Turkey Point CT alternative generating option, based on net levelized costs (in $/kW-month). In addition, the RSM provided for each resource the net costs in total present value dollars. The preliminary total cost of a portfolio was simply the sum of the present value net costs of each of the resources that made up the portfolio. However, seven additional elements needed to be considered in the calculation of a final total cost for each portfolio:

- Value of surplus capacity
- Transmission integration
- Capacity-related transmission loss impacts
- Energy-related transmission loss impacts
- Increased operating costs of Southeast Florida gas turbines (GTs)
- Residual value
- Net equity adjustment.

Value of surplus capacity: If a portfolio provided more than 1,066 MW in 2007, then the portfolio was deemed to have surplus capacity. This capacity had value because it could potentially be sold as a single-year capacity sale in 2007 and would reduce FPL's capacity needs in 2008 and beyond. Thus, in subsequent solicitations, FPL would not have to request as much capacity as it otherwise would if it only acquired or developed exactly 1,066 MW of capacity in its current efforts. The value of surplus capacity is dependent on the market price for capacity in 2007 and beyond. Sedway Consulting assumed a value of $4.35/kW-month in 2007, escalating thereafter at 1.7 percent per year. This estimate represented a trended value for the net cost of the filler unit that was used in the evaluation. As a net cost, it included the projected energy savings from the filler's CC operations and therefore essentially reflected a peaking type of capacity cost. The present value of the surplus capacity benefits for a portfolio was deducted from the portfolio's preliminary total cost. Thus, a portfolio that was well in excess of the required capacity may have had a rather high preliminary total cost (associated with the large amount of capacity in the portfolio) but would have had a mitigating deduction in the form of surplus capacity benefits.

The inclusion of a surplus capacity benefit in the RSM portfolio results placed those results on a more comparable footing with the EGEAS portfolios. While no explicit surplus capacity benefit was calculated to supplement the EGEAS results, EGEAS largely captured this benefit in the long-range expansion plans that it developed for each portfolio.

Transmission integration: Under the direction of an independent transmission planning consultant, estimates of the costs of integrating different portfolios of specific proposals into the FPL network were developed. With a large addition of new generation to a utility system, several portions of the transmission grid may need to be reinforced. This can entail the construction of new circuits or the reconductoring and upgrading of existing transmission lines. The present value of revenue requirements for these transmission integration projects was added to each portfolio, based on the estimation of the necessary investments to accommodate all of the generation resources in that portfolio.

Capacity-related transmission loss impacts: The independent transmission consultant and FPL developed estimates for FPL's peak-hour system transmission losses for each portfolio of resources for each year of the study period. The Turkey Point CC portfolio had the lowest 2007 system losses and was therefore selected as the reference portfolio for the calculation of additional costs for the other portfolios. Those additional costs were calculated by recognizing that the incremental peak-hour transmission losses represented lost capacity that FPL would need to replace or purchase in order to bring each portfolio back up to a level that would be comparable with the reference portfolio. The cost of this capacity was established by FPL in its RFP as $5.00/kW-month in 2009. FPL chose to escalate the value thereafter by 1.7 percent. Sedway Consulting decided to use FPL's capacity price for the capacity-related transmission loss calculation to minimize confusion and maintain consistency with the EGEAS-based results. Alternatively, Sedway Consulting could have used the capacity price stream that was developed for its surplus capacity benefit calculations (of approximately $4.50/kW-month in 2009, escalating at 1.7 percent thereafter). However, this would have had minimal impact on the final portfolio cost differentials – reducing those differentials by less than $2 million.

Energy-related transmission loss impacts: For each portfolio of resources for each year of the study period, the independent transmission consultant and FPL developed estimates not only for FPL's peak-hour system transmission losses but average-hour losses as well. These two annual values for each portfolio were used to calculate the energy-related transmission losses that would have to be made up in each hour in order to bring each portfolio's total system generation back up to a level that would be comparable with the reference portfolio. The peak-hour transmission losses were assumed to apply to the highest 10 percent of the hours of a year (thus, for a total of 876 hours). The average-hour transmission losses were assumed to apply to the remaining 90 percent of the hours (i.e., 7,884 hours). Using EGEAS, FPL developed two $/MWh system marginal energy rates for each year of the analysis – one for the 10 percent highest-load hours of the year and a second for the remaining 90 percent lower-load hours of the year. The high-load marginal energy rate was multiplied by each portfolio's incremental peak-hour transmission loss and 876 hours to calculate the portfolio's annual additional marginal energy costs for the high-load hours. A similar calculation was performed for the 90 percent lower-load hours, using the marginal energy rate for the lower 90 percent of the year's hours, a portfolio's average-hour losses, and 7,884 hours. Together, these additional marginal energy costs represented the added costs of marginal generation on the FPL system that would be called on to make up for the hourly incremental transmission losses associated with each portfolio (relative to the reference portfolio).

Increased operating costs of Southeast Florida GTs: According to FPL, the southeast region of the state is becoming transmission-constrained such that GTs have or will be required to operate out of economic order to preserve system reliability. Therefore, for those portfolios that did not include sufficient generation in Southeast Florida, it was expected that FPL's existing GTs in that area would have to be dispatched more often than if all of the 2007 capacity need was met with generation sited there. For each portfolio, FPL estimated the likely additional runtime of its Southeast Florida GTs because of transmission constraints (relative to the Turkey Point CC portfolio) and the associated costs of operating those resources instead of more cost-effective generation than would have been the case had those constraints been relieved by siting the 2007 capacity in Southeast Florida.

Residual value: The revenue requirements calculations for the Next Planned Generating Unit and the Turkey Point CT alternative generating option were both based on a cost recovery period of 25 years. Thus, if brought in service in 2007, they were assumed to be paid off by 2031 – the end of the study period[1]. However, FPL's Turkey Point CC or CT projects, if developed, would probably have operating lives beyond the end of the study period. Thus, based on the revenue requirements assumptions that were used in the analysis, FPL's customers would have paid for these facilities by 2031 and would continue to benefit from the project's capacity for a number of years beyond that. Given this, Sedway Consulting calculated a residual value for both the Next Planned Generating Unit and the Turkey Point CT alternative generating option and deducted these values from the preliminary total cost of each portfolio that included one or the other of these facilities. The residual value calculation valued the post-2031 capacity of the Next Planned Generating Unit and the Turkey Point CT alternative generating option for another 10 years based on an escalating assumption for the value of capacity. Thus, the capacity for the Next Planned Generating Unit and the Turkey Point CT alternative generating option was multiplied by a \$/kW-year value in each year from 2032 through 2041. That \$/kW-year capacity value was the same \$4.35/kW-month – escalated out to 2032 and beyond – as was used in the surplus capacity calculation. This additional 10 years of capacity was not assumed to be free, however. Although construction costs will be entirely paid off, FPL customers will still have to pay continuing capacity-related charges such as fixed O&M, annual capital replacement costs, and start-up costs. Typically, when a facility nears the end of its operating life, the owner curtails additional investment of incremental capital costs. Thus, for the final 10 years (2032 through 2040),

[1] For modeling purposes, all resources were assumed to commence operation on January 1, 2007. Thus, 25-year resources were assumed to provide energy deliveries from January 1, 2007 through December 31, 2031.

Sedway Consulting assumed that the annual incremental capital investments would be approximately one-half of the annual projections for the 2007-2031 time period.

The energy benefits of the FPL facilities were ignored in the residual value analysis; thus, at least for the CC resource, the residual value was a conservative estimate. Indeed, it is likely that the CC facility would continue to operate at substantial capacity factors during the 10 years of the residual value period – thereby providing less expensive energy for FPL's customers (by displacing more expensive power supplies) than would be the case if the option were never developed. Because EGEAS was not run past 2031, these energy or production cost benefits were not determined. However, they could be substantial.

Net equity adjustment: Rating agencies view some portion of a utility's capacity payment obligations to a power provider as the equivalent of debt on the utility's balance sheet. If a utility does not rebalance its capital structure by issuing stock, this debt equivalent can negatively impact a utility's financial ratios and cause rating agencies to downgrade their opinion of the utility's creditworthiness. This can increase the utility's cost of borrowing. Recent events in the energy industry have underscored the need for companies to maintain a strong balance sheet.

Sedway Consulting corroborated FPL's estimate for each proposal of the costs for FPL to rebalance its capital structure if it were to enter into a PPA with a proposer. This estimate was referred to as an "equity adjustment" because it reflected the present value of the incremental cost of the additional equity that FPL would need to raise to preserve the integrity of its balance sheet. As some offsetting factors, FPL indicated in its RFP that the completion security and performance security aspects of potential PPAs may provide two mitigating elements that would reduce a purchase's equity adjustment. Sedway Consulting corroborated the calculation of those two mitigating reductions to the equity adjustment for each purchase. For each portfolio, the sum of the net/mitigated equity adjustments for whichever outside proposals were in the portfolio was added to the portfolio's preliminary total cost. In summation with the other cost elements described above, this yielded each portfolio's total cost.

Review of EGEAS Results and Additional Cost Elements

In addition to the parallel evaluation process involving the RSM, Sedway Consulting assisted FPL in a review of the EGEAS model results and additional cost elements. This involved four activities:

- Comparing rankings for all evaluated portfolios
- Verifying that the EGEAS output results reflected the correct input assumptions
- Examining the impacts of future generation expansion plans
- Confirming the transmission-loss-related and net equity adjustment calculations.

Sedway Consulting and FPL independently developed rankings of the evaluated portfolios. In comparing these rankings, Sedway Consulting and FPL were able to confirm that the proposals were being interpreted correctly and that all of the latest assumptions and information from proposer clarification communications were incorporated into the EGEAS and RSM models. Generally speaking, the rankings lined up fairly well. In instances where the rankings differed somewhat, Sedway Consulting reviewed the EGEAS output results to confirm that both models were using the same assumptions.

The EGEAS generation expansion plans were studied by Sedway Consulting. These plans represented the model's efforts to maintain the necessary 20 percent reserve margin for the FPL system over time. Given FPL's annual load growth, the retirement of existing resources, and expiration of the new power supply contracts under consideration, EGEAS had to add future generic resources in various years after 2007 to satisfy FPL's reserve margin requirements. This was a more comprehensive process than what was achieved with the RSM. The RSM simply examined single proposals, one at a time, and assumed that they would be replaced with a filler resource of exactly the same size upon the expiration of the proposed PPA. EGEAS had a broader focus. However, given numerous factors that influenced the timing of the addition of new generic resources throughout the study period, the "lumpiness" of EGEAS' long-range generation expansion plans could distort the present value of a portfolio's long-term costs. This "lumpiness" comes from the fact that EGEAS adds new resources in any year in which FPL's reserve margin drops below 20 percent – even if the shortfall is only 1 MW. If the new resource options are large facilities, this can lead to varying levels of surplus capacity in each year. However, FPL chose to use smaller future generic resource alternatives (i.e., filler units) for potential selection in all years following 2023 so that the long-term expansion plans exhibited a "smoother" pattern.

As mentioned above, Sedway Consulting also reviewed and corroborated the calculations of many of the additional costs that were added to the core economic results that were produced by the EGEAS and RSM modeling. Specifically, Sedway Consulting confirmed the following calculations:

- Conversion of transmission integration capital cost estimates into present worth of revenue requirements

- Development of capacity-related costs associated with peak-hour transmission losses

- Development of energy-related costs associated with annual transmission losses

- Development of net equity adjustment values.

RSM Evaluation Results

Table 2 provides a ranking of the outside proposals. For each proposal, the table shows the capacity, length of contract, net levelized fixed price (as described above), and whether or not the proposal ultimately was determined to comply with the RFP's minimum requirements. The information reflects the final RSM ranking, including information provided from Proposal 4's best and final offer. These values do not include transmission integration costs or any of the other additional cost factors discussed above. They just reflect the core costs and operating characteristics of the proposed projects (plus filler costs, where appropriate).

Table 2
Ranking of Outside Proposals

Proposal	Summer Capacity (MW)	Term (years)	Net Levelized Fixed Price ($/kW-month)	Compliant with RFP Minimum Reqts
Proposal 1	50	25	$4.15	No
Proposal 4	447	15	$4.51	Yes
Proposal 5	252	15	$4.81	No
Proposal 2	1220	15	$5.48	No
Proposal 3	1220	25	$5.82	No

Table 3 provides similar information for the Turkey Point CC facility and FPL's alternative CT option. Note, however, that the terms for these facilities are simply represented as the number of years from the start date through the end of the study period (2031) – although the actual lifetime of the facilities would likely be significantly longer.

Table 3
Statistics for FPL Options

Resource	Summer Capacity (MW)	Term (years)	Net Levelized Fixed Price ($/kW-month)
TPCC	1144	25	$4.32
TPCT	648	25	$6.11

Table 4 depicts the base case results for least-cost portfolio (the Turkey Point CC resource) and the other evaluated portfolios. For each element of the portfolios, the table presents the resource's capacity, in-service year, term (i.e., duration), and net cost. The net cost is developed in the RSM and was described above. Also included in the table are additional costs or credits for each portfolio pertaining to surplus capacity benefits, transmission integration costs, capacity-related transmission loss impacts, energy-related transmission loss impacts, additional operating costs of Southeast Florida GTs, residual values, and net equity adjustments. The values in the far right column show the difference in costs (in millions of dollars) between the evaluated portfolios and the least-cost Turkey Point CC portfolio. Note that the differences are accurate but may not match a direct subtraction of the displayed portfolio costs because of rounding.

The Turkey Point CC portfolio was found to be $302 million less expensive than the next cheapest evaluated portfolio. However, given that most of the proposals were found to violate the RFP's minimum requirements, only the portfolio which consisted of the Turkey Point CT alternative and Proposal 4 was deemed to be a compliant portfolio. Its costs were found to be $323 million more than the Turkey Point CC portfolio. All costs are 2003 present values, based on a discount rate of 7.819 percent.

Table 4
Comparison of Evaluated Portfolios

	Net Capacity (MW)	Term (years)	Net Cost ($M)	Difference from TPCC Portfolio ($M)
Best Portfolio -- TPCC				
FPL Turkey Point 4x1 CC	1144	25	$513	
Total:	1144		$513	
Surplus Capacity:	78		($41)	
Transmission Integration:			$0	
Capacity Losses:			$0	
Energy Losses:			$0	
Relative Increased Operating Costs:			$0	
Residual Value:			($62)	
Net Equity Adjustment:			$0	
Net Total Cost:			$409	**$0**
FPL Turkey Point CTs	648	25	$411	
Proposal 4	447	15	$209	
Proposal 5	252	15	$126	
Total:	1347		$746	
Surplus Capacity:	281		($147)	
Transmission Integration:			$56	
Capacity Losses:			$7	
Energy Losses:			$41	
Relative Increased Operating Costs:			$15	
Residual Value:			($34)	
Net Equity Adjustment:			$28	
Net Total Cost:			$712	**$302**
FPL Turkey Point CTs	648	25	$411	
Proposal 4	447	15	$209	
Proposal 1	50	25	$22	
Total:	1145		$641	
Surplus Capacity:	79		($41)	
Transmission Integration:			$56	
Capacity Losses:			$6	
Energy Losses:			$47	
Relative Increased Operating Costs:			$11	
Residual Value:			($34)	
Net Equity Adjustment:			$35	
Net Total Cost:			$720	**$311**
Compliant Portfolio				
FPL Turkey Point CTs	648	25	$411	
Proposal 4	447	15	$209	
Total:	1095		$620	
Surplus Capacity:	29		($15)	
Transmission Integration:			$56	
Capacity Losses:			$11	
Energy Losses:			$64	
Relative Increased Operating Costs:			$16	
Residual Value:			($34)	
Net Equity Adjustment:			$16	
Net Total Cost:			$733	**$323**

Table 4 - Continued
Comparison of Evaluated Portfolios

	Net Capacity (MW)	Term (years)	Net Cost ($M)	Difference from TPCC Portfolio ($M)
Proposal 2	1220	15	$694	
Proposal 1	50	25	$22	
Total:	1270		$716	
Surplus Capacity:	204		($107)	
Transmission Integration:			$6	
Capacity Losses:			$12	
Energy Losses:			$14	
Relative Increased Operating Costs:			$15	
Residual Value:			$0	
Net Equity Adjustment:			$82	
Net Total Cost:			$739	**$329**
Proposal 2	1220	15	$694	
Total:	1220		$694	
Surplus Capacity:	154		($81)	
Transmission Integration:			$7	
Capacity Losses:			$14	
Energy Losses:			$29	
Relative Increased Operating Costs:			$15	
Residual Value:			$0	
Net Equity Adjustment:			$63	
Net Total Cost:			$742	**$332**
Proposal 3	1220	25	$738	
Proposal 1	50	25	$22	
Total:	1270		$759	
Surplus Capacity:	204		($107)	
Transmission Integration:			$6	
Capacity Losses:			$14	
Energy Losses:			$19	
Relative Increased Operating Costs:			$15	
Residual Value:			$0	
Net Equity Adjustment:			$132	
Net Total Cost:			$839	**$429**
Proposal 3	1220	25	$738	
Total:	1220		$738	
Surplus Capacity:	154		($81)	
Transmission Integration:			$7	
Capacity Losses:			$16	
Energy Losses:			$34	
Relative Increased Operating Costs:			$15	
Residual Value:			$0	
Net Equity Adjustment:			$113	
Net Total Cost:			$842	**$433**

Sensitivities

Sedway Consulting believes that the base case analysis of the proposals provided a rigorous assessment of the outside proposals and FPL options. However, it is important to consider whether changes in the study's fundamental assumptions might alter the conclusions. Probably the two most important sensitivities in this type of analysis involve changes in the assumptions concerning gas prices and future resource costs. Given that all but one proposal were power supplies from gas-fired facilities, a high gas price scenario would have little effect on the cost difference between portfolios. In fact, because the Turkey Point CC option was more efficient (i.e., had lower heat rates) than all of the other gas-fired options, a high gas price scenario would have only increased the economic difference between the Turkey Point CC and most other portfolios. The one proposal that was not a gas-fired facility – Proposal 1, the 50 MW coal-fired purchase – represented a relatively small amount of capacity. Although this resource would provide something of a hedge against high gas prices, its small size would have limited its effect in a high gas price sensitivity. Thus, Sedway Consulting focused on the second area (future resource costs) as an appropriate sensitivity.

Future resource costs are characterized in the "filler" resource in the RSM. The filler resource served as replacement capacity for any proposed contract that would expire before 2031. The Turkey Point CC portfolio did not include any filler resource because the FPL facility will continue to operate through 2031 (and beyond). Thus, a scenario with higher costs for the filler resource would only have increased the costs of intermediate-term outside proposals and thus the portfolio cost differences for those portfolios that included such proposals. The important consideration involved whether future resource costs might be lower than the base case filler assumptions. The Turkey Point CC was less expensive than the filler, and arguably the Turkey Point CC project could theoretically be delayed, with its construction following the expiration of some of the intermediate-term proposals. Thus, Sedway Consulting performed a sensitivity analysis whereby the Turkey Point CC project costs were used for the filler resource.

The results of this sensitivity analysis are shown in Table 5. Under this sensitivity, all other portfolios were found to be at least $288 million more expensive than the Turkey Point CC portfolio, with the compliant portfolio being $314 million more.

As discussed above, Sedway Consulting also performed a sensitivity concerning heat rate assumptions. Specifically, the decision was made to evaluate all resources' operating modes (baseload, intermediate, and peaking) consistently with heat rates at 75° F. Table 6 shows how the portfolio cost differentials would have changed if the peaking operating modes for all resources had been evaluated with heat rates at 95° F. The higher-ranked competing portfolios would have increased in cost by approximately $3 million, thereby increasing the portfolio cost differential between them and the Turkey Point CC. The lower-ranked competing portfolios would have decreased in cost by approximately $1 million. In all, these changes in the portfolio cost differentials are fairly immaterial given the overall differences in fundamental portfolio costs relative to the Turkey Point CC.

Table 5
Comparison of Evaluated Portfolios - Filler Sensitivity

	Net Capacity (MW)	Term (years)	Net Cost ($M)	Difference from TPCC Portfolio ($M)
Best Portfolio -- TPCC				
FPL Turkey Point 4x1 CC	1144	25	$513	
Total:	1144		$513	
Surplus Capacity:	78		($41)	
Transmission Integration:			$0	
Capacity Losses:			$0	
Energy Losses:			$0	
Relative Increased Operating Costs:			$0	
Residual Value:			($62)	
Net Equity Adjustment:			$0	
Net Total Cost:			$409	**$0**
FPL Turkey Point CTs	648	25	$411	
Proposal 4	447	15	$200	
Proposal 5	252	15	$121	
Total:	1347		$732	
Surplus Capacity:	281		($147)	
Transmission Integration:			$56	
Capacity Losses:			$7	
Energy Losses:			$41	
Relative Increased Operating Costs:			$15	
Residual Value:			($34)	
Net Equity Adjustment:			$28	
Net Total Cost:			$697	**$288**
FPL Turkey Point CTs	648	25	$411	
Proposal 4	447	15	$200	
Proposal 1	50	25	$22	
Total:	1145		$632	
Surplus Capacity:	79		($41)	
Transmission Integration:			$56	
Capacity Losses:			$6	
Energy Losses:			$47	
Relative Increased Operating Costs:			$11	
Residual Value:			($34)	
Net Equity Adjustment:			$35	
Net Total Cost:			$711	**$302**
Proposal 2	1220	15	$670	
Proposal 1	50	25	$22	
Total:	1270		$691	
Surplus Capacity:	204		($107)	
Transmission Integration:			$6	
Capacity Losses:			$12	
Energy Losses:			$14	
Relative Increased Operating Costs:			$15	
Residual Value:			$0	
Net Equity Adjustment:			$82	
Net Total Cost:			$714	**$305**

Table 5 - Continued
Comparison of Evaluated Portfolios - Filler Sensitivity

	Net Capacity (MW)	Term (years)	Net Cost ($M)	Difference from TPCC Portfolio ($M)
Proposal 2	1220	15	$670	
Total:	1220		$670	
Surplus Capacity:	154		($81)	
Transmission Integration:			$7	
Capacity Losses:			$14	
Energy Losses:			$29	
Relative Increased Operating Costs:			$15	
Residual Value:			$0	
Net Equity Adjustment:			$63	
Net Total Cost:			$717	**$308**
Compliant Portfolio				
FPL Turkey Point CTs	648	25	$411	
Proposal 4	447	15	$200	
Total:	1095		$611	
Surplus Capacity:	29		($15)	
Transmission Integration:			$56	
Capacity Losses:			$11	
Energy Losses:			$64	
Relative Increased Operating Costs:			$16	
Residual Value:			($34)	
Net Equity Adjustment:			$16	
Net Total Cost:			$724	**$314**
Proposal 3	1220	25	$738	
Proposal 1	50	25	$22	
Total:	1270		$759	
Surplus Capacity:	204		($107)	
Transmission Integration:			$6	
Capacity Losses:			$14	
Energy Losses:			$19	
Relative Increased Operating Costs:			$15	
Residual Value:			$0	
Net Equity Adjustment:			$132	
Net Total Cost:			$839	**$429**
Proposal 3	1220	25	$738	
Total:	1220		$738	
Surplus Capacity:	154		($81)	
Transmission Integration:			$7	
Capacity Losses:			$16	
Energy Losses:			$34	
Relative Increased Operating Costs:			$15	
Residual Value:			$0	
Net Equity Adjustment:			$113	
Net Total Cost:			$842	**$433**

Table 6
Comparison of RSM Portfolio Cost Differences
Relative to Portfolio #1
(in $M, CPVRR, 2003$)

Portfolio	At 75° F Heat Rates	At 95° F Heat Rates	Difference*
FPL TP CC	$0	$0	$0
FPL TP 4 CT, Proposal 4, Proposal 5	$302	$305	$3
FPL TP 4 CT, Proposal 4, Proposal 1	$311	$314	$3
FPL TP 4 CT, Proposal 4	$323	$327	$3
Proposal 2, Proposal 1	$329	$329	($1)
Proposal 2	$332	$332	($1)
Proposal 3, Proposal 1	$429	$428	($1)
Proposal 3	$433	$432	($1)

*Differences are accurate but may not match the expected results because of rounding

Conclusions

Sedway Consulting performed an independent and parallel evaluation of the responses to FPL's 2003 resource RFP and concluded that the Turkey Point CC represented the lowest-cost option for meeting FPL's 2007 resource needs. This single-resource portfolio was found to be $323 million less expensive under base case assumptions than the competing compliant portfolio. Also, in the filler sensitivity analysis and the heat rate sensitivity analysis, the Turkey Point CC portfolio was found to be the lower-cost option by $314 million and $327 million, respectively, relative to the competing compliant portfolio.