UNITED PROFESSIONALS COMPANY, L.L.C.

TERREBONNE PARISH CONSOLIDATED GOVERNMENT LEPA-1 REPORT

NOVEMBER 2019

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INTRODUCTION

United Professionals Company ("UPC") was engaged by Terrebonne Parish Consolidated Government ("TPCG"[1]) to develop this. The principles of UPC who have contributed to this report are R. Lane Sisung, Dr. J. Thomas McGuckin, Robert Vosberg, and Paul Chastant. Profiles of these individuals are attached to this report. Mr. Sisung has spent much of the last decade leading UPC's team of consultants in providing utility regulatory consulting in Louisiana, primarily providing consulting services to the Louisiana Public Service Commission in matters, such as: ratemaking, generation certification, integration and operations of utilities with the Regional Transmission Organizations ("RTO") of Midcontinent Independent System Operator ("MISO") and Southwest Power Pool ("SPP"), as well as, numerous other utility-related matters.

The purpose of this report is to review the previous decision to invest in the LEPA-1 generation facility ("LEPA-1" or the "Project"), which is owned and operated by the Louisiana Energy & Power Authority ("LEPA" or "Authority") and the TPCG's 40.9% "Entitlement Share" in the Project and to investigate potential options that may minimize any negative impacts the Project may have imposed upon TPCG.

The report is organized with an Executive Summary, which includes a description of Major Findings and Recommendations, and the more detailed Report. The Report includes: (1) A description of LEPA; (2) TPCG's Relationship to LEPA and LEPA's Relationship to MISO; (3) Description of TPCG Generation; (4) The Decision to Implement LEPA-1; (5) Development, Design, Construction and Operation Issues Surrounding LEPA-1; (6) A Timeline of LEPA-1; and (7) a Post-Hoc Review of matters associated with LEPA-1.

[1] The TPCG utility system mainly serves ratepayers within the incorporated limits of the City of Houma. Many past reports reference "City of Houma", and therefore, there will be references to Houma throughout this report. Any references in this report to the City of Houma must be understood to incorporate the City of Houma's consolidation into the TPCG.

INDEX OF DEFINED TERMS

ALP Project- Acadiana Load Pocket Project

April 2008 ERG Report- April 2008 Energy & Resource Consulting Group Report to LEPA: Transmission and Capital Cost Estimates

Authority- Louisiana Energy & Power Authority

BA- Balancing Authority

CT- Combustion Turbine

CCGT- Combined Cycle Combustion Turbine

Design Engineer- Burns & Roe Enterprises, Inc.

EPC Contract- Engineering, Procurement, and Construction Contract

ERG- Energy & Resource Consulting Group

GDS- GDS Associates Inc.

Guaranteed Commercial Operation Date- October 13, 2015

Houma- The City of Houma as the load participating with LEPA in MISO.

ICAP- Original Installed Capacity Ratings

IRP- Integrated Resource Plan

January 2009 LEPA Report- January 2009 Louisiana Energy & Power Authority Report to Terrebonne Parish Consolidated Government: Regaining Control through New Generation

January 2010 GDS Report- January 2010 GDS Associates Inc. Report to Houma and Morgan City: Power Supply Feasibility Analysis

July 2008 ERG Report- July 2008 Energy & Resource Consulting Group Report to LEPA: LEPA Strategic Supply and Transmission Issues – Summary of Transmission Results and Going Forward Strategic Supply Issues

July 2010 GDS Report- July 2010 GDS Report to Houma: Power Supply Feasibility Analysis of Participation in LEPA's Generation Project

LBA- Local Balancing Authority

Legacy Units- Terrebonne Parish Consolidated Government's Unit #14, Unit #15 and Unit #16 Steam Generators Units

LEPA- Louisiana Energy & Power Authority

LEPA-1- LEPA-1 Generation Facility

LMP- Locational Marginal Prices

LSE- Load Serving Entity

May 2008 URS Report- May 2008 URS, Inc. Report to Houma: Terrebonne Parish Consolidated Government, City of Houma Electrical System, Review and Recommendations

MISO- Midcontinent Independent System Operator

MW- Megawatts

$/Mwh- Dollars Per Megawatt Hour

November 2012 GDS Report- November 2012 GDS Report to Houma: Power Supply Feasibility Analysis of Participation in LEPA's Generation Project

PSA- Power Sales Agreement

PRA- MISO Capacity Planning Resource Auction

Project- LEPA-1 Generation Facility

R&M- Robbins and Morton Group

R&M Claim- April 18, 2016 Request for Equitable Adjustment to Contract Time and Contract Price

RTO- Regional Transmission Organizations

September 2009 GDS Power Supply Feasibility Analysis- September 2009 GDS Associates Inc. Report to Morgan City and Terrebonne Parish Consolidated Government: Power Supply Feasibility Analysis

September 2009 GDS Transmission Assessment Report- September 2009 GDS Associates Inc. Report to Morgan City and Terrebonne Parish Consolidated Government: Transmission Assessment

SPP- Southwest Power Pool

SSR- System Support Resource

TEA- The Energy Authority

TPCG- Terrebonne Parish Consolidated Government

ZRCs- Zonal Resource Credits

EXECUTIVE SUMMARY

LEPA and its Relationship to TPCG

LEPA is a political subdivision of the State of Louisiana, created by the State Legislature in 1979 to assist municipalities with their power and energy needs. Municipalities may voluntarily join LEPA and participate with LEPA in various manners. Some municipalities become "Full-Service Members" of LEPA, whereby they allow LEPA to fully plan and operate their municipal electrical system. Other municipalities utilize LEPA by selectively participating in varying contractual relationships, or levels of service, that LEPA provides. TPCG is not a Full-Service Member of LEPA, as TPCG itself plans its own electrical system, operates its owned generators, and otherwise contracts for purchased power agreements of capacity and energy. TPCG's relationship with LEPA is twofold.

> First, TPCG has entered into two Power Sales Agreements ("PSA") with LEPA for generation to be provided from (a) LEPA's participation in the Rodermacher 2 plant and (b) the LEPA- 1 plant. Each PSA obligates TPCG to pay for an allocable share of all of the cost of the generation. For example, in the case of LEPA-1, TPCG is obligated to pay for 40.9% of all of the costs of LEPA-1. LEPA used the financial commitments it received from the PSAs obtained from TPCG and other municipalities to then secure funds to allow (a) its participation in the Rodermacher 2 plant which is owned and operated by CLECO and (b) to secure its construction and operation in its own name of the LEPA-1 Unit. For 2018, pursuant to the LEPA-1 PSA, TPCG funded LEPA with $3.8 million dollars, primarily composed of net losses of $2.7M and a surplus funding of $1.1M. the $2.7M loss is comprised of Fixed and Variable costs. The Fixed costs are comprised of $2.25 million in debt service, $867,000 in Fixed Operation costs (e.g. staff to run the plant), $190,000 in LEPA administrative services, $113,000 in a Project Renewals and Replacement fund; and $73,000 for contingencies. All of the fixed costs have to be funded regardless of the actual operations of the LEPA-1 Unit. In addition to the fixed costs, TPCG pays its portion of the variable costs associated with the actual production of energy from the units which LEPA sells in the MISO market. However, the revenues collected from the sales offset those costs and should generate a positive generator margin. In 2018, LEPA-1 yielded a net positive

margin from tthe sale of energy in the among of $769,000. The combination of the fixed costs and the net generator margin is what produced the 2018 net loss from LEPA-1 in the amount or $2.7M.

Second, TPCG has contracted with LEPA to act as Houma's local balancing authority, whereby LEPA is responsible for interacting with the regional transmission organization to balance Houma's daily load and generation needs.

The concept of new generation, which eventually culminated in the decision to invest in the LEPA-1 Unit, began in 2008, when LEPA began first proposing generation projects to be built by LEPA. TPCG's final decision to participate in LEPA-1, via an executed PSA, was made in 2013. This report was commissioned to review that decision-making process.

Major Findings

1. **TPCG Did Not Need Generation Capacity.** This was known prior to TPCG's decision to invest in LEPA-1. The Load and Resources forecasts presented in the 2013 report of LEPA's consultant, Energy & Resource Consulting Group ("ERG"), showed that upon TPCG adding the proposed allocable share of LEPA-1 to its generation portfolio that TPCG would be long generation (i.e. have more generation than it needs) by approximately that same amount of generation (22.7 MW). There were no needed physical retirements of TPCG's existing units projected to reduce that capacity. In making its decision to participate in LEPA-sponsored generation, TPCG independently commissioned, GDS Associates Inc. ("GDS") to provide consulting services. However, the scope provided to GDS for its engagement was not designed to have GDS first identify generation capacity that was needed. Rather, the scope of the engagement directed GDS to optimize a portfolio that included the potential retirement of one or more of TPCG's three steam generators, designated as Unit #14, Unit #15 and Unit #16 (collectively referred to as the "Legacy Units") replaced with *new generation*. In its report, GDS states: "While Houma currently enjoys a considerable margin of surplus capacity as compared to its load, there are no definitive plans to make a significant investment in capital projects that would extend the useful life or increase the reliability/availability of the existing steam-turbine generators." GDS has since specified that this statement represented that Houma had taken the position that the Legacy Units would not be invested in and

maintained. However, this statement does not reconcile with the fact that Houma also provided GDS with cost estimates for extending the useful life of the Legacy Units, or the fact that the GDS optimization actually considered, as one option, keeping all three Legacy Units in service. In fact, GDS's final recommendation was for the continued service of some of the Legacy Units, along with the addition of a 25MW of a new Combined cycle generator provided by LEPA and a 15MW of a new combustion turbine generator, either provided by LEPA or self-built by Houma. Further, Tom Bourg, Utility Director for TPCG, stated on the record at the July 26, 2010 Terrebonne Parish Consolidated Government meeting that, "it was expected that it was reasonable that Houma would try to maintain all steam turbines in service but only depend on 40MW of that capacity." It is evident that TPCG had never made a decision to retire any of the Legacy Units, which has since been proven out by the fact that none of the Legacy Units were retired. TPCG had not identified any need for additional generation capacity. While GDS's recommendation was in compliance with the scope of its engagement, their recommendation called for the retirement of Legacy Units—Legacy Units that had no identified need for retirement—which resulted in a high cost, risky investment in new generation capacity that was not needed. Without a given capacity need, LEPA-1 has proven to-date to be a very expensive gamble into unneeded generation capacity.

2. **The Decisions of ELL, CLECO, and LEPA to join MISO Prior to the Bond Issuance for LEPA-1 Should Have Called for TPCG to Take a Much Bigger Pause and Re-evaluation than was Completed.** With Entergy, Cleco, and LEPA's known entrance into the MISO, LEPA and TPCG were provided a truly independent party, MISO, to analyze transmission service requests, which afforded greater transparency and access to the transmission system. MISO was also expected to provide access to a short-term capacity market to address any potential concerns of unexpected loss of one of the Legacy Units. To the extent Houma's need for generation may have been driven by the concern for an unscheduled loss of a Legacy Unit, then a more detailed analysis of the flexibility and alternatives provided by the MISO Capacity Planning Resource Auction ("PRA") should have been considered. Further, MISO was to provide a Day-Ahead Energy and Ancillary Market, which would provide Houma access to daily energy prices--not at the cost of the three Legacy Units, but rather at the Locational Marginal Prices ("LMP") of an open market. LMP is composed of three components: the Marginal Energy component, the Congestion component, and the Line Loss

component. The Marginal Energy component provides all MISO-wide load, Houma included, with access to the marginal cost of energy reliably serving the entire MISO market for each hour. This means that once in MISO, Houma would be paying energy prices based upon the prices determined by the marginal price of the last unit needed to reliably serve load from the total stack of available generators in MISO, as stacked from the lowest cost generation available to the highest. While the Congestion Cost component of LMP may limit some of the MISO market energy savings, the GDS 2012 Report indicated that the impact of the Congestion Cost component of LMP would be minimal.[2] With the fundamental changes in the transmission grid and electric market in Louisiana introduced by MISO, and the lack of an identified need for capacity, it would have been prudent to observe the actual experience of Houma in the MISO South market to determine the benefits that would be experienced from MISO prior to committing to a large and risky investment intended to generate the same type of marginal energy savings.

3. **<u>LEPA-1 was a Risky Investment for TPCG, which Upon Examination of the Underlying Analysis, was Actually Projected to Generate Annual Losses.</u>** ***TPCG's decision to invest in LEPA-1 guaranteed TPCG financially supporting LEPA's investment of over $50 million that has produced current financial obligations to TPCG of approximately $3 million per year, which costs are to be borne for approximately 30 years.*** Counterbalanced against that large financial commitment, the 2012 Updated GDS report only projected MISO market-based savings from the sale of energy in the market from its preferred portfolio of $775,000 based on high gas prices, or $370,000 based on low gas prices. And, in order to match the exact GDS assumptions used to generate that projection of $755.000 of savings, TPCG would have additionally been required to invest over another approximately $10 million in 15 MW of CT capacity, which GDS projected would increase annual fixed costs by another $1.5 million per year.[3] So, with no need for new generation, TPCG was committing to over $5M in annual fixed operations and maintenance costs, for a projected

[2] The report showed that the difference in projected LMP savings as between "with" the new units and "without" the new units was $193,000 per year in the GDS base case (less than 26% of the total projected savings) and $77,000 in the GDS low gas case (less than 21% of the total projected savings). The majority of the GDS projected MISO savings was derived from projected Generator Margins and Financial Transmission Rights. Generator Margins represent the projected net benefit LEPA-1 was to generate from receiving LMP as income against the actual cost of the generation. FTR are revenues received to essentially reimburse the cost paid by the load for congestion on transmission paths historically supported by that load. Neither of these projections have been realized, as is discussed in more detail below.
[3] Appendixes to GDS 2010 Report.

savings of $755,000 of variable energy savings. ***The GDS supporting analysis itself, thus, projected that TPCG was expected to lose over $4 million per year, to invest in new generation that it did not need.***

4. **The Investment into LEPA-1 was Especially Risky, because it Involved an Unneeded Generator, at least as far as TPCG was Concerned, to be Provided by a Principle Party who was Designing, Procuring, and Constructing a $120.8 Million Combined Cycle Generator for the First Time.** Generation investment is a risky proposition for utilities with extensive experience in delivering these types of projects, much less an entity taking on this type of project for the first time. ***That risk was exacerbated by LEPA utilizing a bi-furcated contracting practice, allowing parties to pass blame, resulting in LEPA-1's participating members underwriting all of the risk.*** The risk has been, and continues to be, realized with LEPA delivering the LEPA-1 project late, over-budget, and in a manner that possesses materially-diminished efficiency and utilization compared to what was projected.
5. **LEPA-1 has been Significantly More Inefficient and Underutilized than was Originally Projected.** LEPA-1 has a higher heat rate than originally specified, and has excessive periods of unavailability and deratings, and accordingly, is being underutilized when compared to original projections. ***Originally, LEPA-1 was projected to have a utilization rate of around 74%, however, statistics for 2016 and 2017 indicate a utilization rate below 50%.*** In fact, according to reports generated by LEPA, due to outages, deratings, and other issues for the period of January 2017 through March 2019, LEPA-1 was only available for full dispatch less than 57% of available days. For the most recent first quarter of 2019, LEPA-1 was only available for full dispatch less than 37% of available days. As a result of the poor availability and performance, in 2017, LEPA-1 was 116% more expensive on a $/Mwh basis than originally projected. Even if LEPA-1 were able to hit its 2018 projected budgeted utilization, the Unit would still have had an energy cost 52% higher than originally projected. The higher energy cost caused by the higher heat rate is a disadvantage in the MISO day ahead and real time markets, contributing to a lower utilization rate than projected, which when coupled with the lack of availability, has caused TPCG and the other participating members to have to absorb a higher amount of fixed and overhead costs for the LEPA-1 Unit.

   In fact, due to the poor performance of LEPA-1, LEPA has actually delivered material ***negative*** net Generator Margins, as opposed to the projected $250,000 and $154,000 of projected positive Generator Margins. Even prior to accounting for debt service, LEPA-1 had a negative Generator Margin of $828,825 in 2017, and $288,657 in 2018. When debt service and other costs are considered, LEPA-1 generated a net loss to TPCG of $3.9M in 2017, and a net loss to TPCG of $2.7M in 2018.

6. **As of July 11, 2019, TPCG Has become Aware that a LEPA Consultant has Recommended a Complete Shutdown of the LEPA-1 Unit, which will Make a Bad Situation Worse**. On July 11, as this Report was being concluded, LEPA's General Manager informed TPCG that, due to continuing operational problems and shutdowns of the LEPA-1 Unit, LEPA had retained Dresser Rand to review reports from the manufacturer, GE; and that Dresser Rand recommended not running the Unit until damaged blades on a hot section of turbine are fixed. GE has estimated that repairs/replacements could cost as much as $6 million or more. **As mentioned above, the only parties underwriting the potential $6 million in damage, which was either caused from manufacturing, design, or operations, is TPCG and the other LEPA-1 participants; and TPCG's share is 40.9% of whatever that cost will prove.**

7. **Lower Gas Prices are a Contributing Factor**. The low natural gas prices that have been experienced over the last five years has exacerbated the negative impacts that TPCG has experienced from LEPA-1. However, as was discussed and illustrated in the GDS 2012 report, ***reduced gas prices was a known risk at the time of the investment and provided one more cautionary signal prior to the making of the investment in unneeded capacity***. Further, based on the lack of availability of LEPA-1 and access to all of the stack of MISO generators with equivalent or lower heat rates, it is highly unlikely that, even with higher gas prices, there would have been savings necessary to absorb the costs incurred by TPCG.

8. **There were Risky and/or Unsupported Assumptions in the Reports Recommending the Investments.**

   The Reports recommending the investments into LEPA-1 included what is commonly referred to as a "Base Case" scenario, as well as, various sensitivity scenarios, which make changes to some of the assumptions in the Base Case. The two primary GDS Reports for which TPCG relied upon had its Base Case assume that Houma had no access to market energy purchases. This is an unrealistic scenario, which did not reflect recent actual experience or what could be reasonably expected to occur. In the 2010 GDS Report, when a sensitivity scenario was included which showed access to market purchases, the projected savings for the investment dramatically reduced by approximately 75% from $3 million in savings to $800,000 in savings. Designating a completely unrealistic scenario, with materially higher savings than could be reasonably expected as a Base Case, most likely caused the impression that this scenario was the most realistic opportunity that should be expected. It was not.

The Reports also assumed that CLECO would retire its Teche Generating Units, and that lost generation would be replaced with more remote located generation, stressing the transmission system, and increasing the need for local generation and the savings to be produced by LEPA-1. UPC has been unable to locate any independent support for the projection of Teche retirements, and over 360 MW of Teche generation continues today--and, as was announced recently, will continue to be run until the Teche units fail.

The GDS reports included as savings a pro rata portion of $2.5 million of fixed operations and maintenance costs estimated for the total of the three Legacy Units. In discussions with finance and the utility departments of TPCG, UPC has been unable to confirm this was a reasonable assumption as there is no direct correlation in costs to operating one, two, or three units.

Additionally, there were statements made by Mr. Bourg at a July 6, 2010 meeting that GDS has confirmed that the optimum location to lessen the transmission constraints of the combined cycle plant is nearer to Morgan City and the Cleco System than in Houma, as it's not as beneficial to making the system work in Houma. UPC's takeaway from the GDS Transmission Assessment is that siting the generation closer to Morgan City was found to be the best result for the combined load of Houma and Morgan City. However, when just looking independently at the benefits to a Houma BA, serving just the Houma load the generator could have just as easily been sited in Houma, which would have produced reliability benefits to Houma. By siting the unit in Morgan City, Morgan City now possesses that reliability benefit. Considering TPCG was funding over 40% of the Project, it seems that the reliability benefits should have been considered by TPCG in the site selection process.

9. **TPCG Failed to Follow the Recommendation of GDS.** GDS recommended that TPCG invest in a preferred portfolio that included an investment into LEPA-1, plus an investment in 15 MW of Combustion Turbine ("CT") capacity, plus the retirement of approximately ½

of the Legacy Units. Underlying this specific recommendation was the expected result that TPCG would be left in a projected equilibrium position of its generation to its projected load needs. TPCG did not acquire the 15 MW of CT, but rather only invested in LEPA-1. More importantly, TPCG also did not retire any units to maintain an equilibrium of its generation to its projected load needs, leaving TPCG long generation, and increasing its costs associated with maintaining both its Legacy Units and its investment into LEPA-1.

10. LEPA-1 Full-Service Members have Benefited from LEPA-1, while TPCG Has Not. With TPCG's decision to not retire its Legacy Units and to remain long, LEPA has been able to have its full-service members of Plaquemines and Morgan City retire 89 MW of their legacy capacity, allowing them to achieve significant savings, while TPCG continues to provide regional reliability and capacity to the MISO market at the significant cost associated with maintaining both its Legacy Units and its expensive LEPA-1 investment. While TPCG is paying the aforementioned approximately $3 million per year for its allocation of the full cost of LEPA-1 generation it does not need, Plaquemines and Morgan City are acquiring the capacity they need at a small fraction of that cost per MW from the MISO Planning Resource Auction (MISO PRA), and these pennies on the dollar are all that TPCG receives for supplying that exces generation to the PRA. For example for the 2017/2018 MISO planning year TPCG only received approximately $48,000 for supplying its excess generation to the PRA as opposed to the approximately $3 million in costs it was having to carry. Meanwhile, Plaquemines and Morgan City were able to shut their plants down and achieve those savings, as the then replaced that generation with the low-cost generation provided by the PRA.

11. TPCG Never Fully Considered PPA Generation w/ Transmission as an Alternative to LEPA-1. Even if it was assumed that TPCG had a need to acquire generation, all options of potential generation supply to meet that need should have been analyzed in detail. After reviewing the reports from all of the LEPA, Morgan city, and Houma consultants, UPC cannot find any analysis where the costs, risks, and potential benefits of LEPA-1 was directly compared against the costs, risks, and potential benefits of contracted for wholesale generation with associated transmission upgrades. LEPA's references to the "roadblocks" associated with a PPA with transmission option were only supported in detail with a 2008 proposed contract for generation with SWEPCO for generation not connected to the transmission grid from which LEPA members take power, at a time well prior to the introduction of MISO into the market.

The July 2010 and November 2012 GDS Reports to TPCG state that they were specifically limited in scope by TPCG to consider new generation. The reports both make reference to LEPA's position that wholesale PPA generation with transmission upgrades was not being considered because, in the past, it was associated with cost prohibitive transmission upgrades. However, UPC cannot find where this position was ever supported with any independent direct analysis. To be clear, UPC is not opining that a PPA with a transmission solution would have been a more cost beneficial solution for TPCG. Nevertheless, if the concerns with considering a PPA solution were related to the potential high cost of transmission, LEPA-1 was itself a high cost proposition, and therefore, the expected high cost of a PPA solution should not have been an automatically disqualifying concern. Even accepting the historical experiences of LEPA concerning the high cost of a PPA's with transmission upgrades as true, a best practice would have been for that proposition to be market tested against all options in any analysis, which could result in TPCG investing over $48 million in acquiring risky generation it did not need to satisfy its capacity needs. ***In fact, in two of its early reports, GDS actually recommended that new generation be compared against purchased power alternatives; yet, UPC cannot find where this suggestion was ever included in the following scopes of work directed to GDS.***

12. **TPCG has Outdated and/or Non-Existent Contractual Relationships with LEPA and MISO.** As discussed in this report, LEPA acts as Houma's Local Balancing Authority("LBA"), and LEPA acts as Houma's Load Serving Entity ('LSE") with regards to Houma's capacity in the MISO Planning Resource Auction. Further, The Energy Authority ("TEA"), as an agent for LEPA, acts as the Market Participant for LEPA, and thus TPCG and Houma, in MISO. In the materials provided, UPC could not find any contractual documents related to these relationships, other than a 2003 extension of a 1995 contract with LEPA, which referenced pre-MISO services. **TPCG needs to evaluate TPCG/Houma becoming its own Load Serving Entity so that it can be in control of its own capacity length and future needs.** TPCG should also investigate if there is any possibility—and/or advantage— to The Energy Authority acting as a Market Participant directly on TPCG's behalf. And, in any event, once the best paths forward in these regards are determined, TPCG needs to work

with LEPA, MISO, and/or The Energy Authority to document the specifics of the finally chosen relationships.

13. **TPCG's Electrical Rates Do Not Appear Out of Line with Regulated Rates in State.** In reviewing TPCG's rates, and comparing them with an average of the rates charged by regulated utilities in the State of Louisiana, TPCG is competitive with the average rates charged by regulated Louisiana utilities. TPCG is approximately $2.00 less on a 1,000-kWh bill, and over $20 less than the highest 1,000 kWh bill of Cleco. If, ***and only if***, it is determined that more revenue is ultimately needed to assist TPCG's in absorbing some of the losses produced by its investment in LEPA-1, there appears to be room to support some additional amount of revenue and remain relatively competitive with other utility rates in the State. ***However, to cover the complete losses of LEPA-1, TPCG would have to raise its rates to a level that would be highly uncompetitive and a burden on the ratepayers of Houma.***
14. **TPCG's Investment Into LEPA-1 Negatively Impacted Terrebonne Parish Consolidated Government's Bonding Capacity.** TPCG's investment into the unneeded LEPA-1 generation has restricted TPCG's ability to pledge the revenues of the entire utility division for any other needed purpose of the TPCG utility system. Further, the losses being incurred from TPCG's investment into LEPA-1 have reduced the net funds available for other available bonding capacity.

Conclusions and Recommendations:

1. **TPCG likely cannot solve its problem by selling its ownership in LEPA-1.** ***For TPCG, the LEPA-1 Unit is now an unfortunate fact. TPCG owns expensive, less-than-advertised in efficiency generation, which it did not need if it was going to maintain all three of its current generators operational. While TPCG can pursue options to sell its share of LEPA-1, UPC does not believe that there would be much of an economically-viable market for such an ownership share.*** UPC has observed that the market for used, more efficient combined cycle generation is about 26% of the installed price TPCG paid for LEPA-1.
2. **There is no need to currently retire any of the Legacy Units. However, before spending any material amounts on a future needed overhaul of any of the Legacy Units or related boilers, TPCG needs to explore retiring the unit via the MISO Attachment Y Process.** All three units are currently in working condition, with no reason to expect a catastrophic

failure in the near to intermediate future. GE has stated in correspondence to TPCG that, from its experience, with proper maintenance these units can last 50 to 75 years. TPCG has maintained the Legacy Units in good condition. Further, TPCG's utility staff has expressed the opinion that the boilers are not in any immediate danger of failure. Based on these conditions, and the fact that all three Legacy Units have recently been simultaneously dispatched for reliability, there is no recommendation to immediately shut down any of the Legacy Units. Further, supporting the decision not to currently shutdown any of the Legacy Units is that, based on discussions with TPCG, the operational savings from such a shutdown would be minimal.

However, the next time TPCG is considering a material investment into any of the Legacy Units, there needs to be a detailed examination of the potential financial and reliability benefits, as well as costs associated with retiring any such unit, as opposed to making that investment for continued operations.

Generating units are considered for retirement in MISO via the Attachment Y Process. Generally speaking, if TPCG were to submit a MISO Attachment Y Filing for the retirement of Units #14 and #15, and/or Unit #16, then MISO would perform an analysis of the impact of that proposed retirement, and one of two following alternatives would occur. The first potential outcome is that the study would provide comfort to TPCG that their system will remain reliable with the retirement, and the units may be allowed to be retired; in which case, TPCG would save 100% of the costs of the needed investment and the minimal annual expenses savings that may be realized from retiring less than all of the units. Alternatively, MISO may determine that the units need to remain in service, in which case the units would be designated as a System Support Resource ("SSR"). Because an SSR Unit is required for system reliability, the costs associated with keeping the SSR Unit in service are designated as necessary uplift for regional reliability, and as a result, shared by those who benefit from that system reliability. In this case, TPCG could, at least partially, be compensated for the costs of maintaining and operating those Legacy Units, until such time as the regional system is upgraded to a point where the Legacy Unit(s) can be retired. Under the current system conditions, the Legacy Units are almost exclusively dispatched for reliability purposes, and therefore, it would not be surprising if the Units were designated as SSR Units.

Finally, any decision to retire a Legacy Unit would call into question a provision in the PSA and associated documents, whereby LEPA may make a claim that they could prevent such a retirement. I defer to legal counsel on this issue, but, if LEPA does indeed have such a right, this was an atrocious concession by TPCG to allow LEPA to force it to maintain excess capacity for the benefit of its other LEPA members, essentially making TPCG a subservient to the needs of LEPA, at LEPA's sole discretion.

3. **TPCG should monitor all future investments they make into their grid to determine potential eligibility for MISO 30.9 credits.** In reviewing materials for this report, UPC found an estimated $3,455,000 in recommended Transmission System upgrades, some of which are in progress and have been completed. Section 30.9 of the MISO Tariff provides that certain upgrades in facilities can be deemed as a transmission facility investment integrated with the Transmission System and may therefore be eligible to receive recovery--either through a billing credit, or some other mechanism. As TPCG makes improvements to its system, it should work with MISO to determine if any of its upgrades are eligible for such a credit.[4]

4. **TPCG needs to work with MISO to gain an understanding of the deratings of its Legacy Units.** Original Installed Capacity Ratings ("ICAP") utilized in the 2013 Consulting Engineers Report and the 2012 Updated GDS Report[5] showed Houma Unit #14 with an ICAP of 11.6 MW, Houma Unit #15 with an ICAP of 24.8 MW, and Houma Unit 16 with an ICAP of 39.4 MW, for a total of 76 MW ICAP.[6] However at the time of these reports, the Effective ICAP reported by MISO was 10.7 MW, 24.4 MW, and 27 MW—for a total of 62.1 MW Reductions in the ICAPs of the Legacy Units—resulting in reductions in PRA revenues. As a result, TPCG needs to work with MISO to ensure there Effective ICAPs are being properly determined. [7]

5. **TPCG should analyze and reconstitute its contractual relationships with LEPA, MISO and/or TEA.** A further recommendation is related to the fact that UPC has only been able to

[4] Per discussions with the Parish President, UPC is willing to assist TPCG in initiating and establishing the communications and processes that would allow TPCG to perform this task moving forward on its own.

[5] Terrebonne Parish Consolidated Government (Houma, Louisiana), "Updated Power Supply Feasibility Analysis of Participation in LEPA'2 Generation Projects", Prepared and Submitted by GDS Associates Inc., November 14, 2012

[6] The 76 MW does not match the 56.7 MW listed in table 2. The units were first downgraded in ICAP rating by MISO in 2015.

[7] Per discussions with the Parish President, UPC is willing to assist TPCG in initiating and establishing the communications and processes that would allow TPCG to perform this task moving forward on its own.

locate a 2003 contract between TPCG and LEPA, which renews a 1995 contract on a month-to-month basis for load services designed prior to LEPA joining MISO. This contract was also entered into prior to LEPA's subcontracting to TEA. TPCG should modernize its contract with LEPA for LBA services, and it should investigate the advantages and disadvantages to acting as its own LSE. TPCG should also consider directly engaging TEA to provide Market Participant services directly on TPCG's behalf.[8]

6. **TPCG needs to remin actively involved in LEPA's proposed soutions related to the shutdown and return of LEPA-**1.

Conclusion

TPCG has made a bad investment into LEPA-1 and has little recourse. The LEPA-1 Unit has not performed as to projections, and even if it had, TPCG would be losing potentially millions of dollars a year. Now that the LEPA-1 Unit is being shutdown with a potential expense of $6 million just to get it operating correctly, a bad investment has been made worse. Due to the nature of the PSA obligations, and the contracting decisions made by LEPA, the only parties left underwriting the losses are TPCG and the other Project participants. TPCG needs to implement the recommendations made herein to improve its organization and to try and minimize the impacts the best it can. However, based on the firm obligations of the PSA, and the undesirability of the poor performing LEPA-1, in a generation-long market, there is likely little mitigation to be found.

[8] Per discussions with the Parish President, UPC is willing to assist TPCG in this endeavor.

REPORT

I. Description of LEPA

LEPA has been described in materials reviewed by UPC as:

> *LEPA was created as a political subdivision of the State of Louisiana by the Louisiana Legislature on July 20, 1979, pursuant to Chapter 10-A, Section 4545.1 through 4545.37 of the Louisiana Revised Statutes of 1950, as amended (the "Act"), with full corporate power to provide facilities for the generation and transmission of electric power and energy for the benefits of its member municipalities ("Members"). LEPA is empowered to acquire, construct, operate and maintain electric generating facilities solely or in common with others, to employ agents in the construction, operation and maintenance of any of its generating and transmission facilities and to exercise the power of eminent domain to the extent provided in the Act. Under the Act, transmission facilities can be acquired or constructed only if LEPA is not able to provide for transmission requirements through contracts with investor-owned electric utilities having available existing transmission facilities. LEPA is not authorized to sell or to provide for the transmission of electric power and energy at retail.*
>
> *LEPA is authorized to contract with its Members to provide all or part of their requirements for wholesale electricity and to issue revenue bonds to finance its ownership of electric generating and transmission facilities. As of the effective date of the Act, any Louisiana municipality which was engaged in generation, transmission, or distribution of electricity is eligible for membership in the Authority.* [9]

A. LEPA Members

LEPA has a total of 17 Members. Different LEPA member entities have different claims to the different generators and take different levels of service from LEPA. Seven LEPA members have full-service contracts and are referred to as "Full-Service Members".[10] LEPA's Full-Service Members

[9] 2013 Consulting Engineer's Report, "ERG", Attachment B to The Official Statement, ($120,770,000 Louisiana Energy & Power Authority, Power Project Revenue Bonds, LEPA Unit No.1, Series 2013A, 2014. by Energy & Resource Consulting Group L.L.C., B-2 There are annual subsequent reports. The UPC report also makes extensive reference to the ERG 2016 Consulting Engineer's Report, Report on LEPA Unit No. 1, to the Louisiana Energy and Power Authority.).

[10] 2016 Consulting Engineer's Report (There are 7 Full Service Members- the cities of Morgan City, New Roads, Plaquemine, Rayne, Vidalia, and Winnfield and the Town of Welsh. On June 1, 2016, the Town of Jonesville entered into a Full Requirement Service Agreement with the Authority. On June 1, 2016, New Roads terminated its Full Requirement Service Agreement with the Authority).

do not necessarily provide any generation. If they do own generation, they turn the resources over to LEPA, which assumes responsibility for operations, maintenance, and allocation of costs. TPCG and the City of Alexandria, Louisiana take additional services from LEPA through contractual arrangements.

LEPA additionally provides service to its Full-Service Members and non- full-service TPCG and Alexandria through the operations of the its "Energy Control Center". The services provided by the Energy Control Center to specific members is described in the 2016 Consulting Engineer Report.

> *The Energy Control Center is operated seven days a week, and is utilized by the authority on a real time basis to;*
>
> *(1) monitor the loads of its Member Cities of Morgan City, New Roads, Plaquemine, Rayne, Vidalia, Welsh Winnfield, Houma, and Alexandria;*
>
> *(2) monitor and control the generation of Members under operating agreements with LEPA, namely, the Member Cities of Houma, Morgan City, Plaquemine, New Roads,*
>
> *(3) monitor and control the scheduled flow of energy from LEPA operated and owned generating resources including its twenty percent share of Rodemacher Unit No. 2. schedule, and off-system purchases; and*
>
> *(4) monitor and control the power flows between LEPA's Local Balancing Authority[11] ("LBA") and the LBAs of CLECO, EGSL, and ELL to which its Members are interconnected and to assure compliance with the reliability standards of the North American Electric Reliability Corporation ("NERC").*

B. LEPA Generation

LEPA's generation is a combination of: (1) generator units, or partial generator units, owned by LEPA and contracted through "Entitlement Shares" to various members; (2) Full-Service Members' generation resources, for which control has been granted to LEPA; and (3) generation resources that LEPA procures in order to meet the remaining needs of its Full-Service Members. The two major units directly owned and controlled by LEPA and contracted to various members via "Entitlement

[11] A Local Balancing Authority is defined by MISO as the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

Shares", are Rodemacher 2 and LEPA-1, the unit which is the subject of this report. Additionally, LEPA controls shares of hydroelectric generation from Southwestern Power Authority and Sidney Murray Hydro facility.

Rodemacher 2

> *Rodemacher Unit No. 2 ("RPS2") is a 523 MW rated coal-fired generating unit which commenced commercial operation on August 19, 1982, is located in northwest Rapides Parish near Boyce, Louisiana, and is situated approximately two miles west of the Red River and the main line of the Texas and Pacific Railway, and about one mile west of Louisiana Highway No. 1. LEPA's share of RPS2 amounts to 104.6 MW, CLECO owns 156.9 MW, and the Lafayette Public Power Authority ("LPPA") fifty percent (50%) share that equals 261.5 MW. CLECO, under terms of the Joint Owners Agreement, has sole responsibility to operate, maintain, and dispatch RPS2 in accordance with Prudent Utility Practice as defined in the Joint Owners Agreement. Under provisions of the Joint Owners Agreement, LEPA pays CLECO an annual management fee based on the number of kilowatt-hours generated by RPS2.*
>
> *On April 3, 2013, the Authority issued $28,590,000 of Power Project Revenue Bonds (Rodemacher Unit No. 2), 2013 Series for the purpose of funding the Authority's share of costs associated with environmental upgrade capital improvements required to achieve compliance with the U.S. Environmental Protection Agency ("EPA") Mercury and Air Toxics Standards Rule ("MATS") pertaining to its twenty percent (20%) undivided ownership interest in RPS2 and its Common and Related Facilities. RPS2's compliance with MATS must be achieved by the MATS effective date, April 16, 2015 and all required emissions control equipment for RPS2 must be fully operational. Completion of the RPS2 environmental upgrades are planned for April 16, 2014, which is a full year before the MATS effective date.*
>
> *The LEPA Member Cities of Alexandria, Houma, Jonesville, Morgan City and New Roads are Participants for LEPA's share of RPS2. The Participants receive electric power and energy from their respective Entitlement Shares in RPS2 pursuant to their power sales contracts with LEPA. The aggregate of the Participants' Entitlement Shares equals 100 percent of LEPA's share of RPS2.*[12]

[12] 2013 Consulting Engineer's Report, B-22.

Table from 2013 Consulting Engineer's Report		
Participant	**Entitlement Share**	**Project (%)**
Alexandria	55.26	52.83%
Houma	22.70	21.70%
Jonesville	2.96	383.0%
Morgan City and New	23.68	22.64%
Total	**104.60**	**100.00%**

LEPA-1, The Project

> *The Project consists of LEPA's 100 percent ownership of a 64 MW (nominal) natural-gas fired combined cycle generating unit, a gas transmission line for natural gas service to the generating unit, and related transmission plant and control equipment. The Project is located west of the Joseph J. Cefalu, Sr. Municipal Steam Plant on Parcel 25B-2 of the H&B Young Foundation, an approximately 7.1-acre site located at 1333 Youngs Rd. Morgan City, Louisiana 70380. The electrical transmission interconnection connects the Project to the Cleco Power LLC ("Cleco") transmission system through a 138kV air insulated 3-breaker ring bus switchyard located at the Project.*[13]

LEPA-1 was a joint decision by LEPA-1 members. Originally proposed by LEPA in 2010, members had an October 2010 deadline to participate in the Project by fronting for a $1.75 million engineering study. Each members' contribution of this initiation fee determined the membership shares of the final project.[14] Table 1 below indicates entitlement shares to the LEPA-1.[15]

Table 1: LEPA-1 2016 Participant Share	
Participant	**Entitlement Share (net)**
Houma	25.0
Plaquemine	10.3
Morgan City	10.0
Rayne	7.9
Vidalia	6.3
Jonesville	1.6
Total	**61.1**

[13] 2016 Consulting Engineer's Report, Page 1-1.
[14] There were originally 9 members that initially contributed to the study. However, by the time of the LEPA-1 bond issue, membership had dropped to six.
[15] Ibid Page I-2.

The Project will be discussed in more detail throughout this report.

Southwestern Power Administration

The 2013 Consulting Engineer's Report filing provided the following description and membership allocation of the Southwestern Power Authority hydroelectric power.[16]

> *LEPA purchases hydroelectric generation from the Southwestern Power Administration ("SWPA") for ten of its Members which are entitled to receive allocations of SWPA peaking power. All power and energy is transmitted to the Authority's Members in accordance with the terms and conditions of a Point-To-Point Transmission Service Agreement under Entergy's Open Access Transmission Tariff ("OATT") and the Authority's NITS Agreement with CLECO. Current LEPA Member SWPA allocations are shown in following text Table.*

SWPA Allocations	
Participant	***Kilowatts***
Alexandria	*10,400*
Houma	*4,500*
Jonesville	*500*
Minden	*2,300*
Morgan City	*3,100*
Plaquemine	*2,400*
Rayne	*600*
Ruston	*4,700*
Vidalia	*900*
Winnfield	*1,100*
Total LEPA Members	*30,500*

Sidney A. Murray, Jr. Hydroelectric Project

> *The Town of Vidalia, Louisiana receives an entitlement of run of the river hydroelectric power and energy from the 192 MW Sidney A. Murray, Jr. Hydroelectric Project owned and operated by the Catalyst Hydroelectric Limited Partnership. The City of Vidalia purchases six percent (6%) of the energy with an option to purchase up to fifteen percent (15%) on a graduated basis of the plant's run*

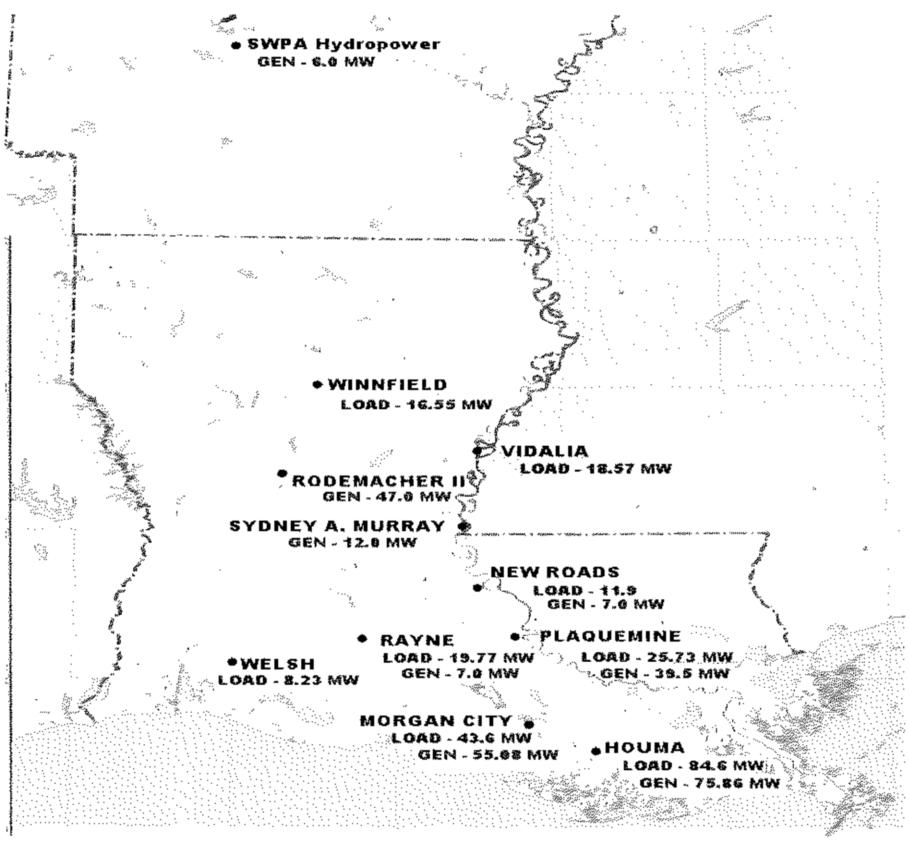
[16] 2013 Consulting Engineer's Report, Attachment B-23.

of river output over the life of the contract. On March 30, 1990, the Authority entered into an agreement with the City of Vidalia to purchase its surplus hydroelectric energy for use in supply to its full requirements service Members. On December 12, 2005, the Authority and the City of Vidalia entered into a replacement agreement ("2005 Agreement") regarding the purchase of such energy. The 2005 Agreement is coterminous with Vidalia's Full Requirement Service Agreement with the Authority and continues in force until the expiration of such agreement. The Authority pays for energy purchased under the Vidalia agreement at a rate equal to the Energy Cost Factor as defined in the Authority's Full Requirement Service Agreement, as adjusted for transmission losses.[17]

C. LEPA Map

LEPA is quite geographically diverse through Louisiana, as indicated in Figure 1. Figure 1 does not include LEPA-1 generation capacities, and in the case of Morgan City and Plaquemine, the figure includes generation that has been subsequently retired.

Figure 1: LEPA Load and Generation – before LEPA-1



[17] 2016 Annual Engineering Report, Page 2-3.

II. TPCG's Relationship to LEPA, and LEPA's Relationship to MISO

A. LEPA as the MISO LBA and LSE

The Midcontinent Independent System Operator, Inc ("MISO") is an Independent System Operator ("ISO") and Regional Transmission Organization ("RTO"), providing open-access transmission service and monitoring of the high-voltage transmission system in the Midwest United States, Manitoba, Canada, and a Southern United States region, which includes much of Arkansas, Mississippi, and Louisiana. MISO also operates one of the world's largest real-time energy markets. Entergy and Cleco formally joined MISO in December 2013, although the decision to join MISO was made for Entergy on May 23, 2012[18] and Cleco on June 26, 2013.[19] Since the majority of transmission in the areas served by LEPA is owned and operated by Entergy and Cleco, it necessitated LEPA and/or its members, becoming a member of MISO. LEPA, thus, took on the obligation of becoming a Member for its Full-Service Members and TPCG.[20] Accordingly, LEPA is the designated Local Balancing Authority ("LBA") and Load Serving Entity ("LSE") for TPCG in MISO.

Local Balancing Authority

LEPA joined MISO on May 31, 2013 as a LBA. This relationship is described as:

> *As an LBA in MISO, the Authority is responsible for sending the Net Actual Interchange by interface and the individual tie line flows to the MISO Balancing Authority. The Authority is also responsible for monitoring Member generation systems in real-time and for sending dispatch signals received from the MISO Balancing Authority to the Authority's generation plants.*
>
> *On June 1, 2013 as part of its future integration into MISO, LEPA also began receiving Reliability Coordination services from MISO. MISO acts as the designated NERC Reliability Coordinator ("RC") for the interconnected bulk electric transmission systems throughout MISO's footprint. In its role as RC, MISO ensures the operating reliability of these systems on a planning basis and for real-time system operations. MISO provides the following RC services for all MISO members:*

[18] LPSC Docket No. U-32148.
[19] LPSC Docket No. U-32631.
[20] The City of Alexandria is its own MISO Market Participant but uses LEPA as the LBA.

- *Receives facility and operational data from generator owners and operators, Load Serving Entities ("LSE"), Transmission Owners ("TOs") and operators and distribution providers;*
- *Calculates Interconnection Reliability Operating Limits ("IROL"), including voltage and stability limits, based upon specified generation and transmission equipment ratings;*
- *Performs Reliability Assessment Commitment analyses for the MISO footprint;*
- *Reviews and coordinates planned generation maintenance scheduling;*
- *Receives real-time operational information from LBA's and TOs for monitoring compliance with NERC standards; and*
- *Coordinates system restoration amongst LBA's and Interchange Authorities ("IAs") consistent with federal and state law;*
- *Coordinates reliability processes and actions with and among neighboring RCs in accordance with operating agreements;*
- *Take actions to maintain system voltage and stability at all times;*
- *Implement congestion management actions and directives to TOs, LBAs and IAs to assure system reliability is maintained;*
- *Coordinate reliability processes with neighboring RCs; and*
- *Monitor interchange flows and take actions to assure compliance with Area Control Error requirements.*

Load Serving Entity

LEPA's Load Serving Entity ("LSE") role is to ensure that there is sufficient generation and transmission resources available to balance the load demand of those members. LSE's also forecast individual members own non-coincident peak loads. LEPA acts as the LSE for Houma in MISO. For Full-Service Members, of which Houma is not, LEPA relies on the internal generation of such member and then procures sufficient additional generation from its own resources or purchases from MISO and secondary markets to meet the members load requirements as an LSE. Then in coordination with MISO, LEPA issues dispatch instruction through its control center as an LBA. A LEPA Full-Service Member turns over operations, financial management and control of any units that it owns or participates in to LEPA.

> *In order to meet its obligations under its full requirement service arrangement, LEPA contracts for the purchase of demand and energy from area suppliers and either operates or contracts for the capacity of various Member generating units through Generation Dispatch Agreements and Generation Operating Agreements. As part of this arrangement, two of the Rodemacher Unit No. 2 Participants (the member cities of Morgan City and New Roads) have each reassigned to LEPA their respective entitlement shares of the Project, whereby LEPA re-acquires the output from these Members for use in providing supply to its Full Requirement Service Agreement Members.* [21]

For Houma, who is not a Full Service Member, LEPA acts as the LSE in the annual Planning Resource Auction, however Houma is providing all of its own generation capacity and it appears from an agreement later described between LEPA and The Energy Authority ("TEA") that TEA is now providing load projection services.

Market Participant

A Market Participant ("MP") is a legal entity that is qualified, pursuant to criteria and procedures established by MISO, to: (i) Submit Bilateral Transactions to MISO; (ii) Submit Bids to purchase Energy and Operating Reserves, and /or Offers to supply Energy and Operating Reserves in the Day-Ahead and/or Real-Time Energy and Operating Reserve Markets; (iii) Hold Financial Transmission Rights (FTRs) and submit Bids to purchase, and /or Offers to sell such rights; (iv) Hold Auction Revenue Rights (ARRs); and (v) Settle all payments and charges with MISO.[22] MPs can fill all roles, or may designate Scheduling, Meter Data and Management, Settlements, and Billing Agents.[23] The MP is financially responsible for all its actions and those of its agents.[24] LEPA has designated TEA as the MP with regards to the Houma units and the LEPA load, which includes Houma load.

B. The Energy Authority

The LEPA contract with TEA is dated July 1, 2013, and generally, allows TEA to manage LEPA's resources in the MISO Market, including the Houma Units. More specifically, the contract calls for:

> *(1) TEA will provide the interface between LEPA and the MISO Market.*

[21] 2013 Consulting Engineer's Report, B-21.
[22] MISO Business Practice Manual, at 11.
[23] MISO Business Practice Manual, at 12.
[24] *See id.*

(2) TEA will coordinate with LEPA's operations staff and make all bids and offers into the Market, receive awards from the Markets, provide settlement, manage payments, and provide dispute resolution on LEPA's behalf.

(3) LEPA shall provide to TEA in a timely manner information required by TEA pursuant to this Task Order to prepare and submit bids, offers, and any other submittal as required by MISO.

(4) Commercial Model and Resource Adequacy. TEA shall assist LEPA in identifying LEPA's information required to register and maintain such registration of LEPA's assets in the MISO commercial model. TEA shall assist LEPA in identifying LEPA's information required to comply with MISO's resource adequacy requirements in accordance with "Module E" of the Tariff.

(5) Day ahead Demand Bids. LEPA shall provide information pursuant to this section to TEA and TEA shall coordinate submission of the information to MISO. LEPA shall provide TEA with a Load Forecast for each of LEPA's load points in MISO. LEPA shall share this information via the TEA-provided Member Resource Plan ("MRP") application. LEPA shall submit Fixed Price Demand Bids or Price Sensitive Demand Bids, if any, to TEA via the MRP. TEA shall format the data as the appropriate demand bid and submit to the MISO Day Ahead Market.

(6) Generation Offers. LEPA shall submit costs and operational parameters for its generating units and supply contracts to TEA via the MRP. TEA shall format data as offers and submit to the MISO Day Ahead and Real Time Markets as appropriate. TEA shall provide 24-hour MISO coverage to allow for Real Time Market submissions to the MISO. The Houma Legacy Steam Units are identified as being included in this service.

(7) Day ahead Strategies. Each day as forecast for the next seven days, LEPA shall submit to TEA: Load Forecast, unit input/output curve coefficients, fuel costs, and other system information pertinent to strategy development. TEA shall use reasonable efforts to provide market guidance, analysis, and insights to assist LEP A in optimizing its load and generation assets in the Market.

(8) FinSched and Contract Management. TEA shall provide LEPA with information, as it becomes evident to TEA, of transaction opportunities to purchase or sell to third patty counterparties within the MISO Market (such transaction referred to as a "FinSched"). TEA shall not execute such transaction as described in this section without the prior approval of LEP A and execution of such transactions shall be subject to the terms of this Agreement. In the event such FinSched is executed, TEA shall input the details of such transaction into the MISO portal.

(9) MISO Transaction Reports. TEA shall provide a Day Ahead Awards Report to LEPA. This report includes all load, generation, and Virtual Transaction awards, and Locational Marginal Prices and Market Clearing Prices for all points in LEPA's portfolio. This repot will be made available to LEPA via the then current method utilized by TEA to provide such report.

(10) Financial Transmission Rights ("FTR") and Auction Revenue Rights ("ARR"). TEA shall tabulate LEPA provided information and register the LEPA portfolio for the MISO ARR allocation. TEA shall review and validate MISO entitlements for network, point-to-point, and Grand-Fathered Agreement entitlements. In consultation with LEPA, TEA shall manage the multi-stage MISO ARR nomination and allocation process for Candidate Auction Revenue Rights, including requests for new resource points. TEA shall recommend ARR/FTR strategies based on market simulation runs that observe changes in the system topology. TEA shall bid on MISO FTRs as authorized by LEPA. TEA shall input and track LEPA owned FTRs through its deal capture systems and provide FTR valuations to LEPA.

(11) TEA shall provide LEPA with a statement of MISO settlement activities on a regular basis in coordination with MISO's settlement calendar (currently weekly).

(12) TEA shall provide shadow settlement of LEP A related business with MISO and reconcile MISO invoices.

(13) As it relates to services provided pursuant to this Section A of the Task Order, TEA shall make payments to the MISO and receive payments from the MISO and payments between LEPA and TEA shall be made on the following terms: (i) if an amount is owed MISO, then LEP A shall make payment to TEA one business-day prior to the date TEA must make payment to the MISO; (ii) if an amount is received from an MISO, then TEA shall make payment to LEP A one business day after funds are received from the MISO.

The Contract also considers certain functions "out of scope" for the purposes of the Agreement. These functions must be performed by LEPA. However, if MISO requires certain data submittals or filings that would otherwise be performed by LEPA under this Agreement, to be performed by the MP, then in such an event, LEPA shall prepare the data submittal or filing and provide it to TEA, and TEA shall deliver it to the MISO on LEPA's behalf. Out of scope services include, but are not limited to the following:

(1) *LEPA shall maintain and monitor the network reservations for LEPA and manage its Network Integration Transmission Service agreement.*

(2) Any interaction or obligations with MISO not provided pursuant to this Task Order, including but not limited to provision of any System Control and Data Acquisition systems or telecommunications interconnections with MISO, any reliability obligations or functions, or any activities related to LEPA being a Transmission Owner.

(3) Load forecasting.

(4) Meter Data Management Agent functions.

(5) Generator outage or curtailment reporting.

The contract calls for LEPA to pay TEA a fixed monthly fee of $47,240 per month, with an inflation adjuster. According to a November 2015 Invoice form LEPA to TPCG, TPCG is charged 39.19% of the TEA Resource Management Fee as part of the Energy charges it is assessed.

On April 29, 2016, LEPA authorized another Task Order to TEA for Load Forecasting Services. The compensation for the contract was $1,490 per month, and the initial term for these services was one year, which has been continually extended. During the term of this Task Order, TEA is to create a and manage a load forecast. TEA will build, run, contract for weather forecast data, and maintain the model. The model is to produce an hourly load forecast for the current day and the following nine (9) days. TEA is also to provide reports that provide LEPA managers visibility to the model's performance.

C. Summary of TPCG's Contractual Arrangements with LEPA

UPC has reviewed the materials presented to it. After having done so, UPC has identified no contractual agreements between TPCG and TEA and has only identified only the following contractual commitments between TPCG and LEPA.

1. TPCG Agreement for Load Control and Other Services, dated May 1, 1995.
    a. Was set to expire on December 31, 2000.
    b. Covered load control services defined as utilization of TPCG's generation and telemetry and control facilities for the purpose of remotely controlling TPCG's generation to provide electrical power and energy to meet TPCG's load.

c. The other services deal with Interchange energy, Rodermacher Transmission, SPP Reserve Sharing, short-term emergency power, and energy when TPCG's generating units trip.

d. Also, LEPA was allowed to act as TPCG's agent for the purpose of selling power and energy from TPCG's resources, as required and/or requested by TPCG.

e. These services were all provided for a monthly fee.

f. The contract could be cancelled by either party upon 60 days' notice.

2. Extension of Load Control Agreement, dated October 1, 2003.

   a. Essentially ratified the contract through the expired period and continued the agreement in full force and effect on a month-to-month basis.

Since LEPA has joined MISO, there has been a dramatic changed in how generators and load interface with the grid. Further, since TPCG is currently paying for the services of LEPA, and by extension TEA through LEPA, UPC recommends that TPCG investigate, through discussions with LEPA and TEA, whether it may be in TPCG's best interest to directly engage TEA to act as a MP on TPCG's behalf for some or all of the services that are being provide through LEPA via TEA. Additionally, in any event, once the best path forward is determined, UPC advises that TPCG work with LEPA and/or TEA to design contractual agreements that clearly define the scope of services that will continue to be provided by LEPA as a member of MISO.

III. City of Houma Generation

The City of Houma, as of 2018, has approximately 100 MW of UCAP[25] generation to serve it load obligation of 84 MW. Table 2 summarizes this balance.[26]

Table 2: City of Houma Resource Adequacy for Planning Year 2018/2019	
Generating Unit (UPAC MW)	**MW**
Houma: Unit 14	10.5
Houma: Unit 15	22.4
Houma: Unit 16	23.8
SWPA	3.7
LEPA: Rodemacher Unit 2	20.1
LEPA: LEPA-1	20.1
TOTAL Houma Generation (MW)	**100.6**
Houma's 2018/19 Load Obligation	**84.2**
Houma's Excess Capacity, ZRC Credits	**16.4**

The City of Houma differs from a number of other LEPA members, in that Houma is not a Full-Service Member. Rather, Houma provides its owned and operated generation, as supplemented by Entitlement Shares in the LEPA resources, Rodemacher 2, LEPA-1, and SWPA. Each generating unit is bid into the day ahead and real time markets, and each receive revenue if their bids are accepted and the unit is actually dispatched. The revenue is calculated as the actual amount of energy dispatched, multiplied by the locational marginal price ("LMP"), which is the marginal cost of energy for MISO at that location. Those revenues from the MISO market are used as an offset to the energy costs, creating a net energy margin, a portion of which is then allocated to the City of Houma based

[25] UCAP stands for Unforced Capacity and is calculated as the Installed Capacity ("IPAC") adjusted for outage rates, (1-xFORD, i.e. forced outage rate). This adjustment allows a comparison of resources to the MISO coincident Peak load adjusted for MISO planning reserve margin.
[26] *See* spreadsheet, 2018-19 Houma Resource Adequacy, tab Houma RA Summary. Provided to the City of Houma.

on its entitlement. The energy margin is netted with the load costs that Houma pays into MISO to purchase energy to serve its load to determine Houma's base energy cost to serve the load.[27]

A. Houma's Base and Intermediate Generation

Houma has contracts for Entitlement Shares with LEPA of 20.1 MW, of Rodemacher 2, and added additional base, and intermediate generation by the 25 MW of generation from LEPA-1.[28] For the Rodemacher 2 and LEPA-1 Units, LEPA dispatches these units pursuant to MISO instructions from the day ahead and real time MISO markets.

B. Houma's Legacy Units (Peak Generation)

The three Houma Legacy Units are steam generators designated as Unit #14, Unit #15 and Unit #16. The Legacy Units are older, and accordingly, less efficient. Houma Unit #14 is 50 years old. Houma Unit #15 is 45 years old. Houma Unit 16 is 41 years old.[29] Original capacity estimates utilized in the 2013 Consulting Engineers Report and the 2012 Updated GDS Report[30] showed Houma Unit #14 as rated to 11.6 MW, Houma Unit #15 as rated to 24.8 MW, and Houma Unit 16 as rated to 39.4 MW, for a total of 76 MW.[31] However at the time of this report the Effective ICAP reported by MISO was 10.7 MW, 24.4 MW and 27 MW for a total of 62.1 MW. Houma needs to work with MISO directly to ensure there Effective ICAPs are being properly determined.

Although the Legacy Units are older, all three units have been well maintained and are currently in good and working condition with no reason to expect a catastrophic failure in the near to intermediate future. GE has stated in correspondence to Houma that from experience, with proper maintenance, these units can last 50 to 75 years. Further, Houma's utility staff has expressed the opinion that the boilers are not in any immediate danger of catastrophic failure. Based on the current well-maintained condition of the Legacy Units and the fact that all three units have as recently as 2018 needed to be simultaneously dispatched for reliability, there is no recommendation to immediately shut down any

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[27] There are other costs and credits that are included in the total energy costs, some of which will be discussed later.

[28] The 2016 Consulting Engineer's Report indicates that Houma has a 40.9% entitlement share to 61.1 MW capacity of LEPA-1, Table 1-1. Previous consulting reports had indicated a 22 MW share, see Exhibit 1 of the 2013 Consulting report.

[29] According to a MISO data base on generation, Unit #14 was is service in 1968, Houma #15 in service in 1973 and Houma #16 in service in 1977..

[30] Terrebonne Parish Consolidated Government (Houma, Louisiana), "Updated Power Supply Feasibility Analysis of Participation in LEPA'2 Generation Projects", Prepared and Submitted by GDS Associates Inc., November 14, 2012

[31] The 76 MW does not match the 56.7 MW listed in table 2. The units were first downgraded in UCAP rating by MISO in 2015.

of the Legacy Units. Further, in working with the utility division and accounting department of TPCG, UPC has been unable to identify any material operational savings that could be achieved with just shutting down one or two of the units. As long as one unit is left, TPCG still has to provide an electric utility staff. However, the next time Houma is considering a material capital investment into any of the units, their needs to be a detailed examination of the potential benefits and costs associated with retiring that unit as opposed to making that large capital investment for continued operations.

From discussions with TPCG and based upon correspondence received from LEPA, there seems to be perception that Houma cannot retire its Legacy Units without the cooperation of LEPA due to constraints mandated in the bond documents and/or the power purchase agreement ("PPA") between Houma and LEPA. UPC has identified the following contractual provisions:

> **Provisions from the Power Sales Contract**
>
> **"Combined Utilities System"** shall mean the combined utilities system of the Participant of which the electric power and light plant and system of the Participant is a part. The Participant's electric utility system shall be deemed to be a Combined Utilities System for purposes of this Power Sales Contract if the revenues of the electric utility system (i) are commingled with the revenues of one or more other utility systems owned by the Participant, or (ii) are utilized to pay operating expenses of the Participant's electric utility system and one or more other utility systems owned by the Project Participant, or (iii) are pledged to secure bonds issued to finance one or more other utility systems owned by the Project Participant.[32]
>
> SECTION 27) **Covenants of the Participant**. The Participant covenants and agrees that in accordance with Prudent Utility Practice it shall (i) at all times operate the properties of its Combined Utilities System and the business in connection therewith in an efficient manner and at reasonable cost, (ii) maintain its Combined Utilities System in good repair, working order and condition and (iii) from time to time make all necessary and proper repairs, renewals, replacements, additions, betterments, equipping and furnishing of its Combined Utilities System so that at all times the business carried on in connection therewith shall be properly and advantageously conducted. The Participant covenants and agrees to cooperate with LEPA in the performance of the respective obligations of such Participant and LEPA under this Power Sales Contract and to fix, charge and collect rents, rates, fees and charges for electric power and energy and other services, facilities and

[32] *See* page 3, Definitions Section of the PPA.

> commodities, sold, furnished or supplied through its Combined Utilities System sufficient to provide revenues adequate to meet its obligations under this Power Sales Contract and to pay any and all other amounts payable from or constituting a charge and lien upon such revenues, including amounts sufficient to pay the principal of and interest on all revenue bonds of the Participant now outstanding or hereafter issued for purposes related to its Combined Utilities System or any part thereof.[33]
>
> SECTION 38) **Assignments of Power Sales Contract: Sale of Participant's System**
>
> (c) The Participant agrees that it will not sell, lease or otherwise dispose of all or substantially all of its Combined Utilities System except upon one hundred eighty (180) days prior written notice to LEI'A and, in any event, will not sell, lease or otherwise dispose of the same unless the following conditions are met: (I) LEI'A and the governing bodies of a majority in number of the other Participants shall by appropriate action detinning that such sale, lease or other disposition will not adversely affect the value of this Power Sales Contract as security for the payment of Bonds and interest thereon or affect the eligibility of interest on Bonds for federal tax exempt status[34]

LEPA provided a letter on July 25, 2019 to counsel for TPCG which concluded:

> In summary, it is LEPA's position that, pursuant to the Power Sales Contract between LEPA and Houma dated as of June I, 2013 and the Power Sales Contract regarding Rodemacher Unit No. 2, if Houma decides that it wants to consider retirement of one or more of its units," Houma must give the requisite 180 days prior written notice provided in both Power Sales Contracts. Thereafter, LEPA and the governing bodies of the other participants shall by appropriate action determine that such sale, lease, abandonment or other disposition will not adversely affect Houma's ability to meet its obligations under both Power Sales Contracts and will not adversely affect the value of this Power Sales Contract as security for the payment of Bonds and interest thereon or affect the eligibility of interest on Bonds then outstanding or which could be issued in the future for federal tax-exempt status. Furthermore, as to LEPA Unit No. 1, LEPA has the sole discretion to make such determinations.

Ultimately, the scope/extent of the pledge of property of the combined utility system is a legal question that would have to be addressed if TPCG ever decided to dispose property. It is UPC's

33 *See* page Section 27 of the PPA, Covenants of the Participant

34 *See* page 21, Section 38 of the PPA, Assignment of Power Sales Contract; Sale of Participant System.

opinion that retiring excess generation in no way meets the standard of to (sell, lease or otherwise dispose of *all or substantially all* of its Combined Utilities System) "(emphasis added). If the position of LEPA were to be accepted, this would have been a atrocious concession for TPCG to have made and essentially relegates TPCG to a slave of serving LEPA's needs, in LEPA's sole discretion.

Notwithstanding whether or not LEPA has such rights, ***the next time TPCG is considering a material investment into any of the Legacy Units, their needs to be a detailed examination of the potential financial and reliability benefits and costs associated with retiring that unit as opposed to making that investment for continued operations.*** Solely because of LEPA 1, Houma has a net generation surplus, and as discussed above, after an analysis could find it to be economical to retire some of the Legacy Units. For example, Unit 15's production of 11 MW is within the 16 MW surplus Houma has in 2018. If it were deemed an economical decision, Unit 15 could, thus, be retired to reduce the surplus. At some point in the future, it may also prove to be in TPCG's best financial interest to potentially retire additional Legacy Unit(s) creating a shortage and filling that generation shortage from the MISO Planning Resource Auction ("PRA"), at least for a short-term, as it develops a longer-term solution.

With regards to any decision to potentially retire the Legacy Units, reliability for Houma's load must be the most important consideration. In that regard, it is important to recognize that MISO has designated the Houma node as a commercially significant reliability area.[35] This designation was necessitated because, under high general load conditions, the transmission line connecting Houma to outside generation creates voltage reliability issues. To relieve this pressure, MISO dispatches Houma Units # 14, 15, and 16 inside the Houma "island", and this reduces the load on the outside transmission system. Because the Legacy Units are uneconomical to run, however, Houma receives Revenue Sufficiency Guarantee Payments ("RSG")[36] for the production of energy. Houma does not profit from RSG payments. The RSG payments are set according to MISO market guidelines, and are intended to allow the owner of a RSG unit to recover the uneconomic costs incurred for the reliability dispatch of the unit(s). While RSG does assist with the cost of dispatching units for

[35] 2014-S-004-S-MISO STANDING OPERATING GUIDE REV 03 MISO REAL TIME OPERATIONS, "Houma Reliability Commitment Requirements R03.

[36] Resource Sufficient Guarantee Payments, an uplift payment to compensate for uneconomic dispatch of generation units.

reliability dispatch, it does not help subsidize the costs incurred by the owner of a unit to keep that unit in a state ready to be dispatched.

While acknowledging that the reliability concern will be paramount in any retirement decision, the designation as a commercially significant reliability area should not prevent TPCG from proceeding with a prudent investigation into the retirement of some or all the Legacy Units, because MISO has a process in place to specifically protect the reliability of the system when units are seeking retirement. Whenever an asset owner would like to retire a generation unit, they must file the Attachment Y request with MISO, who then performs a study related to any reliability concerns that may be raised from the proposed retirement, and if a concern is identified, then the requested retiring units may be designated as a System Support Resource ("SSR"). If a unit(s) is designated as an SSR, MISO would require TPCG to not retire that unit(s) until a reliable solution was designed to meet MISO's reliability requirements. Then, to the extent a SSR unit is required to maintain operations as an SSR, MISO would charge all of the load benefitting from the reliability provided by that SSR designation for the costs associated with keeping the unit operational and those charges would be paid to TPCG. It is safe to assume that the most likely beneficiaries that would have to contribute to the continued operations of the Houma Legacy Units should they be designated as a SSR unit would include, LEPA's Full Service Members, Entergy Louisiana, Cleco Power, Lafayette Utility System ("LUS"), and TPCG itself.

In Summary, if no material reliability concern was identified in the Attachment Y study, then TPCG could choose to retire the Legacy Units and save the expense of capital refurbishment and potentially experience some savings from the non-operation of those units. However, if a material reliability concern is identified, then TPCG would be compensated by surrounding loads for their allocable costs of providing that reliability, and those payments would help TPCG subsidize the cost of any needed refurbishments and maintenance of the Legacy Units until the system reliability was solved, at which point the unit(s) would be retired.

IV. Review of the Decision to Implement LEPA-1

The decision for LEPA-1 to be implemented required the decisions of all the Participating Members and LEPA. Each Participating Member needed to review its own capacity needs and energy costs to determine if they wanted to participate.

A. LEPA's Decision to Implement LEPA-1

The 2013 Consulting Engineer's Report describes the LEPA decision as follows,

> *In the past, the Authority has attempted on numerous occasions to secure long term purchased power supply agreements from regional utilities and merchant generators to supplement its existing resources in the wholesale supply to its Members. However, due primarily to the substantial cost of the transmission upgrades that would be required to deliver such power supply resources to the LEPA LBA, the offers of long-term supply resources to LEPA were determined to be uneconomic.*
>
> *As an alternative strategy, for the past several years LEPA has investigated the feasibility of developing new generating resources in the transmission constrained region of its Members' loads in Southeast Louisiana. In an effort to identify locations where new generation could potentially be located and interconnected to deliver power to meet the Authority's load and mitigate area transmission loading and voltage problems, the Authority conducted transmission load flow analyses of the Entergy and CLECO transmission systems. The analyses considered constructing both a gas turbine combined cycle unit and a simple cycle gas turbine unit.*

B. Member Cities' Other than TPCG' Decision to Invest in LEPA 1

A primary factor in each LEPA member's decision to participate in LEPA-1 was the net capacity position of the member. The decisions of members were tentatively made in October 2010, with an obligation for an upfront contribution for an engineering study at a total cost of $1.75 million to be shared among the participants. The 2013 Consulting Engineer's Report came after the 2010 initial commitment, but before for the 2013 bond issue, which cemented each member's participation.

The 2013 Consulting Engineer Report, in Exhibit 1, projected the net capacity position, resource capability minus load, for each of the six members to 2020.[37] UPC has used these projections to analyze the framework in which each member would have made its final decision in 2013. In its

[37] *See* The 2013 Consulting Engineer's Report, at Exhibit 1.

analysis, UPC considered the investment in LEPA-1 in conjunction with the retirement of the Legacy Units that are, or were, owned individually by the members. UPC's analysis used the member's 2020 projected net capacity position, and considered: (1) continued maintenance of all legacy units without the LEPA-1 unit; (2) with LEPA-1 and continued maintenance of legacy units,[38] (3) retirements of selected units but without the new generation, (4) with LEPA-1 but netting out the retirements of the legacy units,[39] and (5) the same scenario as (4) with the addition of the GDS recommendation of a 15 MW CT for Houma. Table 3 indicates the members' net positions for the five scenarios.

Table 3: Net Long and Short Position (MW) of Member Cities

	Projected 2020 Net Surplus/(Deficit) without LEPA-1	Add LEPA-1, no retirements 1/	No LEPA-1 Projected Retirements	Add LEPA-1 and Legacy Retirements	LEPA-1 plus Retirement of 2 Houma Legacy Units plus add 15MW CT Unit 2/
Full service	(col 1)	(col 2)	(col 3)	(col 4)	(col 5)
Morgan City	28.3	38.3	-22.8	-12.8	-12.8
Plaquemine	12.7	23	-25.3	-15	-15
Jonesville 3/	0	0	0	0	0
Rayne	-18.8	-10.9	-18.8	-10.9	-10.9
Vidalia	-20.3	-14	-20.3	-14	-14
NET Full Service	1.9	36.4	-87.2	-52.7	-52.7
Houma	0.6	22.6	-35.8	-13.8	1.2
Net all positions	2.5	59	-123	-66.5	-51.5

1/ According to Exhibit 1, LEPA-1 has an available MW capability of 58 MW.

2/ 2012 Updated GDS Report, Page 11

38 This is the projection of the 2013 Consulting Engineer Report, Exhibit 1 that continued all legacy units in its projection.

39 Morgan City retired Units MGC ST #3 and #4. Plaquemine retired PLQ Units 1 and 2. 2012 Updated GDS Report recommended the Houma retire Units #14 and #15, but Houma did not follow this recommendation.

3/ Jonesville has a supplement contract with Concordia that balances it net capability, if negative, to zero.

From Table 3 column 1, the immediate need for LEPA-1 for any of the LEPA members is not readily clear, either from the Full-Service Members' or TPCG's perspectives. Note that a negative position of a specific Full-Service Member can be made up by the pooling of other Full-Service Members' resources, or outside generation—most likely from MISO. LEPA, as the LSE, has to provide for any deficit through purchase power arrangements or annual purchases through the MISO Planning Resource Auction. However, under the first scenario, the net of all Full-Service Members is positive, and LEPA would use all these resources to balance the collective load. Houma is also net positive in 2020 without LEPA-1. Based solely on this capacity analysis, one would have to assume that future retirements were a significant consideration for LEPA's participating members.

The following paragraphs review the long/short perspective of each individual member.

Morgan City: Morgan City had a projected net surplus of 28 MW in 2020 (col 1), and with the addition of a 10 MW share of LEPA-1, would have an even greater net surplus of 38.3 MW, as illustrated in column 2 of Table 3. Morgan City's decision to invest in LEPA-1 then would only seem to make sense if it included a plan for projected retirements of the older Legacy Units #3 and/or #4 in its decision. As shown in column 3, without LEPA-1 and assuming the retirement of its legacy units, Morgan City would have a projected deficit of 22.8 MW; and as shown in column 4, LEPA-1 partially made up this deficit for a net position of -12.8 MW. Morgan City is a Full-Service Member. So, the deficit would be made up through LEPA's other Full-Service Members and/or purchases in the secondary or MISO markets. Accordingly, from a post-hoc review, it seems as if Morgan City's decision to invest in LEPA-1 would have only been seen as cost effective if there were planned retirements, which the city undertook in 2015, causing a need for capacity and LEPA-1 was projected to be less expensive capacity than other alternatives.

Plaquemine: The 2010 outlook for Plaquemine was similar to that of Morgan City. Plaquemine had a net surplus projected in 2020, even before its participation in LEPA-1. The addition of LEPA-1 would have increased this net surplus. But, Plaquemine subsequently retired Units 1 and 2, which without LEPA-1, would have put it into a negative position of 25.3 MW. LEPA-1 partially made up this deficit to bring it to a negative position of 15 MW. But, as with Morgan City, Plaquemine is a Full-Service Member. So, the deficit was assumed by LEPA. Plaquemine's decision on LEPA-1 had to be similar to Morgan City; such that one would assume that LEPA-1 projected costs on $/Mwh basis would be cheaper than obtaining power in the secondary market.

Jonesville: Jonesville, except for a small participation in Rodemacher 2, relied on a supplemental contract with Concordia for its resource capability to match its load. Its decision to participate in LEPA-1 is assumed to have weighed the projected cost of LEPA-1 against the cost of supplemental power from Concordia. UPC has not been provided the analysis to confirm this assumption, however. Jonesville only partially replaced the Concordia purchase with 1.5 MW of LEPA-1. The 2013 Consulting Engineer's Report notes that Concordia Contract expired in 2015. UPC has not been provided with the materials to know whether that contract was extended, or if Jonesville replaced this generation.

Rayne: Rayne has a Southwest Power Authority contract for hydropower and a small unit, Rayne IC 8&9, as internal resources. The combination of these sources does not meet Rayne's load requirements, and as a result, the municipality relies of its status as a LEPA Full-Service Member to match its load. For Rayne, LEPA-1 partially reduced its dependence on supplemental power, and its decision to invest could have been expected to be based on a cost comparison that LEPA-1 on $/Mwh basis would have been cheaper than obtaining power in the secondary market. UPC, however, has not been provided with the any analysis to support this proposition.

Vidalia: Vidalia also has a Southwest Power Authority contract for hydropower and receives additional power from a 3.0 MW contract for the Sidney Murray Hydro Unit. As with Rayne, the combination of these sources doesn't meet Vidalia's load requirements, and the municipality relies on its status as a LEPA Full-Service Member to supplement its load requirements. Again, similar to Rayne, LEPA-1 partially reduced Vidalia's dependence on supplemental power, and as such, its decision to invest would have been based on the same cost comparison discussed above for Rayne. UPC, however, has not been provided with the any analysis to support this proposition.

C. TPCG's Decision to Invest in LEPA 1

As indicated in Table 4, the City of Houma had sufficient resources before LEPA-1 and had no need for capacity.[40]

[40] *See* 2013 Consulting Engineer's Report, at Exhibit 1.

Table 4: City of Houma Load and Capability			
	2010	**2011**	**2012**
Houma	2010	2011	2012
Peak Demand Responsibility			
System Peak Demand 1/	85.7	84.4	85.9
Plus Transmission Losses	2.6	2.5	2.6
Assumed MISO Coincident Load	83.8	82.6	84.1
Plus Planning Reserves	12.9	14.4	14.0
Total Capacity Requirement	**96.7**	**97.0**	**98.1**
Supplied Resources			
Houma: HMA ST #14	11.6	11.6	11.6
Houma: HMA ST#15	24.8	24.8	24.8
Houma: HMA ST #16	39.4	39.4	39.4
LEPA: Rodemacher	22.7	22.7	22.7
LEPA: SWPA	4.5	4.5	4.5
Total Resources Capacity	**103.0**	**103.0**	**103.0**
Total Capacity Surplus	**6.3**	**6.1**	**5.0**

[1] Projection used weather normalized regression analysis from 2001-2012

[2] Transmission losses are estimated to be 3%

[3] Estimated Planning Reserve Requirement is based on MISO 2013 LOLE Study ICAP calculations

As can be seen from the Table 3, Houma had enough city-owned resources, the steam units (76 MW) with the Rodemacher PPA (22.7 MW) and the SWPA hydro (4.3 MW) to meet peak demands plus planning reserve margins.[41] The relatively tight net surplus indicates that, if a generator would have gone down, Houma would have been in a net deficit position. As LEPA and Houma were becoming participants in MISO, however, this potential net deficit position was not necessarily problematic, because Houma likely would have been able to obtain additional capacity through the MISO PRA auction until it could implement a longer-term generation solution.

Moving to the forward-looking analysis derived from the 2013 the Consultant Engineers and 2012 Updated GDS reports, as illustrated in Column 1 of Table 3, Houma had no projected need for

[41] At the time the Steam units were still rated at 76 MW ICAP. In 2015 they were subsequently downsized.

capacity in 2020. Column 2 of Table 3 illustrates that, without the retirements of Houma's current generation, the addition of LEPA-1 was all unneeded capacity.

Column 3 of Table 3 illustrates the position that Houma would be in if Units 14 and 15 went out of service. Houma would be approximately 36MW short in that instance. Column 4 of Table 3 illustrates Houma's position if it were to have retired those 2 legacy units and then added LEPA-1, and it shows a shortage of generation in the amount of approximately 14MW. Column 5 of Table 3 indicates the GDS proposal to add 15MW of a CT Peaker to address that issue. Column 5 represents GDS's recommendation, which is discussed fully below.

As is illustrated by Table 3, Houma did not need the capacity unless there was an assumption of a loss of one or more of the Legacy Units and UPC has found nothing to support such an assumption. In fact, Mr. Bourg publicly stated at a Juy 26, 2010 council meeting with LEPA present that Mr. Bourg stated that it was expected that it was reasonable that Houma would try to maintain all steam turbines in service. **With no need for capacity, TPCG's decision had to be predicated solely on a belief that LEPA-1 would generate energy savings greater than the fixed cost of the LEPA-1 capacity. As will be shown this was not projected to be the case, and yet, the decision was made to make the investment.**

The process for TPCG's decision began in 2008 and involved numerous presentations and reports from consultants procured by either LEPA, a combination of Morgan City and TPCG, or by TPCG on its own behalf. Below is a review of the various consultants' reports that UPC was provided.

1. April 2008 ERG Report to LEPA: "Transmission and Capital Cost Estimates" ("April 2008 ERG Report")

This initial report set the stage for the subsequent reports that led to the LEPA-1 decision. In the April 2008 ERG Report, ERG discloses that LEPA was exploring a power purchase contract with AEP/SWEPCO. The April 2008 ERG Report then goes on to discuss road blocks seen in negotiation with Entergy for more transmission access.

> *LEPA Met with Entergy and ICT on March 18, 2008 to Discuss Load Flow Modeling Issues related to:*
>
> - *Lack of Capacitor Banks of Houma and Morgan City.*

- *Operation of Morgan City Generating Units in Violation of Reactive Limits.*
- *On April 10, 2008, Entergy Responded to LEPA's Questions, However Entergy/ICT's Answers were Generally Inadequate and Non-Substantive.*

ERG goes on to state in its April 2008 ERG Report that it saw as a roadblock the Entergy/ICT proposal that LEPA commit to a redispatch of Morgan City and Houma generating units whenever a Level 4 Transmission Loading Relief ("TLR") event was anticipated until area transmission improvements could be accomplished as a means to proceed with the AEP/SWPECO transaction. Based upon 2007 Entergy Data at the time, LEPA would be required to start and run Morgan City and Houma units 24 times, for a minimum of 102 Days. And, the proposed redispatch requirement could continue for three or more years.

It is important to note that LEPA-1 being placed into service did nothing to address this concern. Future Houma procured studies projected significant continued dispatch of the Houma Legacy Units and actual experience has shown that the Houma Legacy Units alone were dispatched 29 times in 2017 for 98 days and 26 time in 2018 for 160 days.

The lack of a reduction in Houma Legacy Unit dispatch can at least partly be attributed to the fact that that ERG's recommended solution to reduce that dispatch was to add 140 MW of local generation located in Morgan City and Houma and that generation was to relieve transmission constraints and reduce the requirement of dispatch of more expensive legacy generation, However, this was not the ultimate decision. The final decision was to invest in the less than 64 MW of LEPA-1 located in Morgan City, a considerable amount less of generation with none located in Houma, resulting in less relief of transmission constraints for Houma. The initial problem for which pursuit of new generation was initiated was not even projected to be resolved by the final decision.

The April 2008 ERG Report further states that Entergy/ICT's Facilities Study indicated required transmission upgrades totaling approximately $62 million and Entergy/ICT proposed that LEPA directly fund required area transmission improvements, as indicated in its Facilities Study to reduce the capital cost by elimination Entergy's tax gross up. The April 2008 ERG Report stated that LEPA would have received Financial Transmission Rights in return for its investment, though no details were offered. On this matter, however, the April 2008 ERG Report is a little ambiguous, because on one slide it is stated that, "the *Entergy/ICT Proposal was Untenable to LEPA and Rejected*[,]" but on the very next slide, it is stated, "*LEPA has not formally responded to Entergy/ICT on its direct funding offer and LEPA will continue its dialogue with Entergy/ICT to correct Entergy/ICT's modeling errors.*" UPC cannot find any documentation that shows that dialogue continued, but as will be discussed following, UPC has found where new generation quickly became the preferred course of action.

An additional concern resulting from a review of this initial report in relation to the final decision is that after reviewing the April 2008 ERG Report, in conjunction with all of the subsequent reports of ERG and GDS discussed herein, which all uniformly and firmly take the position that transmission solutions are untenable or cost prohibitive, the above analysis is the only analytical evidence UPC has been able to find of any attempt over the 5 years of making the decision to truly quantify the cost of transmission service with a PPA against the costs and risks of a self-build option. And, this one case involves a provider, SWEPCO, whose units were not connected to the Entergy or Cleco transmission system at the time of the review, nor would they be on the MISO system at the time of the LEPA-1 decision. Assuming there is first determined a valid need for generation, best practices, as evidenced by the Louisiana Public Service Commission's requirement of a Market Based Mechanism, and GDS' own recommendation in its GDS January 2010 report to Houma and Morgan City, would call for a competitive process where all generation solutions are offered the opportunity to compete against one another before such a large and risky capital investment as LEPA-1 was committed. There were, and continue to be, numerous wholesale providers who are long on capacity and energy, and whom are directly connected to the Entergy and Cleco transmission systems, as well as in MISO that may have offered market based PPA prices, which, when coupled with a transmission solution, may have been a less risky, more viable alternative. In fact, UPC located in the documents produced an offer made in December of 2012, prior to the final LEPA-1 decision, from Cleco to LEPA for 50MW of Coughlin for a capacity price of $11.17 per kW/Mo. That compares to the LEPA-1 price of $16.31 per kW/mo., and UPC cannot find any comparison of this offer with transmission costs added and then compared to the cost of LEPA-1.

Returning to the April 2008 ERG Report, the very next slide then immediately posits as "[t]he problem" that the outage of Entergy's Webre–Wells 500kV line has been the limiting contingency which restricts transmission imports into the Houma - Morgan City Area because in the event of an outage of the Webre – wells 500kV line, transmission lines in the Morgan City and Houma area become overloaded and loss of bus voltages occur." The April 2008 ERG Report then uses this as the rationale for an objective of identifying locations where new LEPA generation units can be sited and interconnected to deliver power to LEPA members, while also eliminating area transmission loading and bus voltage problems.

Based on this objective, the April 2008 ERG Report concludes that, based on ERG analysis that installation of a 100 MW combined Cycle Unit at Morgan City and a 40MW simple cycle CT at Houma at an estimated cost of approximately $186 million, "**eliminates all transmission overloads without the need for any transmission upgrades, and therefore these installations along with the installation of proposed capacitor banks at Houma and Morgan City would eliminate area transmission overloads and would maintain acceptable system voltage levels for both normal and first contingency transmission outage system conditions.**"

In retrospect, what is concerning about the conclusion of the April 2008 ERG Report which kicked off the effort that resulted in LEPA-1 is that it states that the impetus for a self-build option was driven by the desire to eliminate transmission overloads, without the need for any transmission upgrades, but as will be seen through a review of all of the reports, the final LEPA-1 solution of 64 MW in Morgan City did nothing to accomplish this goal.

2. May 2008 URS Report to Houma: "Terrebonne Parish Consolidated Government, City of Houma Electrical System, Review and Recommendations" ("May 2008 URS Report")

In May of 2008, Houma commissioned a study on its own behalf from URS, Inc. to review its entire electrical system. The May 2008 URS Report recommended a $37 million comprehensive overhaul of all elements of Houma's electrical system: transmission, generation, distribution, and long-term upgrades to enhance reliability and meet future projected load growth. The following table indicated URS recommendation in overall spending.

DESCRIPTION	ESTIMATED TIC
TRANSMISSION SYSTEM UPGRADES	$3,455,000
DISTRIBUTION SYSTEM UPGRADES	$10,705,000
POWER PLANT UPGRADES	$10,410,000
RECOMMENDED FUTURE IMPROVEMENTS	$8,415,000
TOTAL ESTIMATED SYSTEM IMPROVEMENT COST	**$37,460,000**

The upgrades to power plants did not increase Houma's generation capacity, but rather overhauled and enhanced the capability of existing units. What is materially missing from the May 2008 URS Report is that it does not provide any estimate of the life extension to the Legacy Units that would result from the $10,410,000 of recommended upgrades. This is a missing piece to all of the various reports that were done, and without that knowledge, it is nearly impossible to evaluate a comparison of maintaining the current units, with upgrades, verses acquiring new build generation. GDS used this assumption in its studies used to recommend investing in LEPA-1. One has to assume that since GDS considered making this investment (or a portion thereof) and extending the life of a Legacy Unit that there was an assumption that the useful life would be extended for at least an amount of time where it was reasonable to make that investment.

To enhance import capability, the May 2008 URS Report also recommended the following transmission upgrades:

- Upgrade the 115 kV transmission Line from Norman St. Substation to HGS Substation 2 enough to utilize full transformation capability (100 mVA);
- Construct a second 60 mVA 34.5 kV loop feed from Norman St. Substation to HGS Substation 1;
- Add a new 34.5 kV breaker at the Norman St Substation for the new loop feeder;

- Conduct transmission interconnect study to evaluate alternate loop feed configurations for added capacity and reliability (work in progress).

The URS-provided estimated for these transmission improvements was as follows:

Description	Estimated Construction Cost
Upgrade 115 kV Transmission Line from Norman St. Substation to HGS Substation #2	$2,000,000
Build 34.5 kV Sub-Transmission Line from Norman Street Substation to Cummins Road Substation	350,000
Upgrade the 34.5 kV Sub-Transmission Line from Cummins Road Substation to HGS Substation #2	375,000
Build 34.5 kV Sub-Transmission Line from Southdown Substation to New Substation	200,000
Build 34.5 kV Sub-Transmission Line from New Substation to Existing 34.5 kV line	175,000
Install 34.5 kV Breaker in the Norman Street Substation.	$275,000
Replace HGS Substation 1 Loop Feeder Breaker Relays	80,000
TOTAL ESTIMATED TRANSMISSION UPGRADE COST	$3,455,000

In meeting with the Houma Utility department, it was disclosed that the upgrade of the 115 kV Transmission Line form Norman S. Substation to HGS Substation #2 is in progress and that there was a completion of the installation of the 34.5 kV Breaker in the Norman Street Substation. Section 30.9 of the MISO Tariff provides that certain investments in facilities which can be deemed as a transmission facility integrated with the Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. As Houma makes improvements to its system believed to be transmission upgrades it should work with MISO to determine if any of its upgrades are eligible for this credit.

It is further interesting to note that the May 2008 URS Report stated that, in 2007, Houma generating units only supplied 3% of Houma's annual energy requirements. Specifically, Rodermacher 2 supplied 38.6% and SWPA power supplied 3%, while market purchases were used to supply 55.4% of the annual energy requirements. There was only firm import transmission capability of 26MW. The May 2008 URS Report stated that LEPA was attempting to secure NITS on behalf of membership, including Houma, to facilitate more dependable full import capability and Houma was obligated up to approximately $4 million. These facts illustrate that, even with the limitations of firm transmission, in 2007, Houma was procuring 55.4% of its energy from economic market purchases, and not from its expensive Legacy Units. This is an important fact because: (1) LEPA did acquire NITS service form Entergy and Cleco, and (2) as will be discussed in review of later consulting reports, economic market purchases were not considered as the base case when comparing generator options.

3. July 2008 ERG Report to LEPA: "LEPA Strategic Supply and Transmission Issues – Summary of Transmission Results and Going Forward Strategic Supply Issues" ("July 2008 ERG Report")

The July 2008 ERG Report begins where the April 2008 ERG Report left off by stating that the initial studies performed in coordination with URS indicated that the installation of a 100MW CC at Morgan City and a 40MW CT at Houma, along with a need to add capacitor banks at both Houma and Morgan City, would maintain acceptable system voltage and avoid transmission overloads in the event of the outage of Entergy's Webre-wells 500kV line. The July 2008 ERG Report then goes on to discuss "Optimization Studies" related to that proposition. These Optimization Studies initially conclude that, if only considering a single contingency transmission limitation criterion, the Morgan City Unit sizing could be reduced from 100 MW to 75 MW; but it would still require the 40MW CT at Houma to achieve the acceptable system voltage. Despite this recommendation from the Optimization Studies, the July 2008 ERG Report stated that, "however, in order to maintain operational flexibility, and to support LEPA Member's future load growth requirements a 100MW sized CCGT at Morgan City is still recommended…" Therefore, the next phase of the Optimization Study concluded that, if a 100 MW CCGT were to be maintained at Morgan City, then the 40 MW Houma CT could be down sized to 25 MW, if only considering area line ratings, but that CT would be required to operate close to its full load rating. The Optimization Studies then posits that if, Houma were to upgrade its Norman St. Sub – City of Houma Sub 115k transmission line, the single contingency loss of Entergy's Webre – Wells 500 kV line would not result in underlying transmission system overloads, and in this case, no peaking capacity at Houma would be required. However, a double contingency analysis, which is what the transmission providers would utilize, projected a continued need for the 40 MW generating capacity at Houma to maintain acceptable voltage and to avoid overloading other 115 kV lines in the Morgan City- Houma area. The conclusion of the single and double continency Optimization Studies results was that, although based upon the studies performed, installation of a minimum of 75 MW of CCGT was potentially possible, assuming 40 MW of CT at Houma, installation of 100 MW is recommended to provide LEPA with operational flexibility and support LEPA member load growth. Further, though the single contingency studies performed indicated possibly reducing the Houma CT to 25 MW.

The July 2008 ERG Report then goes on to state that the operation in June echoes transmission study results and the need for new generation to solve transmission availability issues by citing to:

- Firm transmission not available in June for transactions in the market;
- Only day-ahead interruptible service available;
- Requires member units to be run to firm up market purchases; and
- Cleco load regulation service did not negate running inefficient units.

Once again, while UPC acknowledges that these were legitimate concerns in 2008, it is somewhat concerned that it cannot find were these concerns were ever reevaluated, especially after Entergy, Cleco, and LEPA all had planned, and agreed, to join MISO.

Slide 14 of the July 2008 ERG Report acknowledges that there is little savings of 9%, compared to the risk of the CT/CC, and poses the question: "[d]oes LEPA have to install generation[,]" and "what are the costs of the proposed CT/CC under various gas assumptions…" The slide then states that, LEPA is currently short on planning reserves and LEPA must either install generation, acquire a firm purchase, or risk reliability of service to its members.

UPC notes here that, while LEPA may have been short, Houma was not projected to be short. LEPA needed Houma to participate in its project to provide the demand necessary to justify the new generation, Houma did not need the LEPA generation. Further, although a firm purchase was stated as an option, UPC cannot find where a firm purchase was ever evaluated past this report.

The reasons that a firm purchase was not considered were provided for in Slide 19 of the July 2008 ERG Report, which stated that, "[b]ased upon transmission planning on Entergy system, no short or long-term solutions in sight." And, slide 20 provided that, "[f]irm Purchases have failed due to transmission 'road blocks' and process which requires finding a source, running a study on transmission availability from that source, evaluation transmission results and funding improvements and upgrades." However, UPC notes that these are the same processes that the decision for new generation underwent.

Slide 23 of the July 2008 ERG Report discusses advantages to self-build, but UPC notes several countervailing observations related to these purported advantages when viewed in light of the time that the final decision was made in 2013.

- Known and more efficient heat rate on self-operated generation.
    - At the time of the final decision, MISO was introducing a daily energy market with locational marginal prices set largely by investor owned utilities and merchant renewable generators across a broad footprint which prices should have been expected to be, and have proven to be, materially lower than the costs of Houma's Legacy units and within a reasonable range of the marginal costs of CCGT units.
- Opportunity for physical and financial hedges to reduce volatility to members.
    - The MISO energy market was to provide a market hedge of fuel sources, limited only by reliability constrained dispatch.
- Capital is invested in the LEPA Asset in lieu of third-party transmission system.
    - A valid observation, but a countervailing observation is that, with the open access and transparency of MISO, the new transmission investment might result in an increase in transmission availability for the future providing a more diverse opporutinty for future power purchase agreements and new generation. Further MISO provides a mechanism for the investor of transmission upgrades to be compensated by other parties that use that transmission line.
- Mitigates risks on loss of Cleco load regulation service and need to run inefficient units.
    - Prior to the investment decision, GDS projected a continued need for the inefficient units to be run and there has been no actual reduction in running Houma's inefficient units.
- Transmission issues significantly mitigated and market access dramatically improved.
    - This advantage was based on the assumption of 100MW of CC in Morgan City and 40MW in Houma. The 64MW of LEPA-1 in Morgan City did not provide this projected advantage of significant mitigation of transmission issue mitigation to Houma. Further access to market costs for energy greatly improved by MISO.
- Should increase ability for market purchases.
    - MISO, combined with planned ALP transmission upgrades and no planned retirements for Teche generation, increased the ability for market purchases.
- New generation heat rates proximate to market on peak and shoulder peak generation bids.

- MISO would provide Houma with access to market based on peak and shoulder peak generation prices via the reliability constrained, economically dispatched energy market. Further LEPA-1 has yet to consistently perform to its projected standards.

4. January 2009 LEPA Report to Terrebonne Parish Consolidated Government: "Regaining Control through New Generation" ("January 2009 LEPA Report")

The title indicates the LEPA position of "new generation" that had clearly been established by this date. In this presentation of bullet points, LEPA is more adamant in rejecting transmission as an alternative, and in adamantly suggesting generation. First, LEPA summarized its negotiations with Entergy to increase imports in the talking point presentation.[42]

A slide in the January 2009 LEPA Report also states that, when LEPA has applied for long-term transmission service pursuant to an Entergy/Cleco study, the result always ended with a requirement for upgrades, and then, a statement is made that, "[t]he cost of transmission upgrades required exceed the economic benefit of a PPA." However, as noted, the only evidence of this statement that was provided in prior reports is one incomplete interaction related to a proposed 2008 PPA between LEPA and SWEPCO, whose power was not interconnected with ELL or Cleco's transmission grid.

To further support LEPA's position related to a lack of support for PPA's with a transmission solution, it provided several observations, which UPC, once again with the benefit of some hindsight, comments on below:

- *Transmission Upgrades are "Lumpy".*
    - Generation investment is lumpy.
- *The Access Granted Ends with the Termination of the PPA.*
    - With the regional upgrades completed for increased transmission access, it is likely to provide more diverse opportunities for economically priced power in the future. Further MISO provides a mechanism for compensation to the investor of transmission upgrades from other parties use of those upgrades.
- *Difficult to Culminate with a PPA.*
    - Generation is also difficult to procure, construct and operate, and difficulty in procuring a PPA should not be an eliminating factor for considering a PPA with transmission upgrades in competition with generation.

[42] *See Regaining Control Through New Generation,* Louisiana Energy & Power Authority (January 2009).

- *Subject to Market Flux.*
    - All power acquisition decisions are subject to market flux. Over the last 30 years, there have been times when gas units were market-favored, when coal units were market-favored, and when there has been little difference between the two. PPAs with diverse generator owners may actually allow for a more blended fuel cost for the long-term, and MISO helps to smooth out the market flux with footprint-wide economic dispatch.
- *No Liquid Hub for Electric Market.*
    - This concern was significantly mitigated with the introduction of MISO.
- *Load Growth.*
    - UPC does not see a concern of significant load growth related to Houma, especially at the time of the final decision, and MISO allows for short-term generation deficits to be met with generation from the PRA market which allows for longer-term solutions to be developed when they are needed.

After this analysis, the January 2009 LEPA Report then asked, "[w]hat is the answer?" and the analysis answers its own query with "[c]onstruct generation…" This Q&A is then supported with a bullet that transmission hurdles nullify benefits from PPAs.

To be clear, UPC does not question whether all of the concerns considered by LEPA were legitimate concerns to be considered. In fact, UPC acknowledges that they are. UPC's concern related to Houma' consideration of these issues is twofold. First, Houma did not need the generation capacity in the first place. Second, if the purpose was to try and make an economic gamble on procuring fixed cost generation which would deliver more variable energy savings than fixed costs, then all options should have been tested. UPC cannot find where these concerns were ever directly addressed in a benefits and costs analysis, comparing the risky and expensive proposition of participating in LEPA's new-build generation against the acquisition of a PPA with transmission upgrades. This concern is especially heightened knowing that ELL, Cleco, and LEPA were all entering MISO, which independently was going to provide Houma with access to lower energy prices and more transparency in potential transmission solutions.

5. September 2009 GDS Report to Morgan City and Terrebonne Parish Consolidated Government: "Transmission Assessment" ("September 2009 GDS Transmission Assessment Report")

Morgan City and TPCG first retained the services of GDS to assist them with studying the feasibility of leaving the LEPA balancing authority and forming a new balancing authority, either by forming one combined balancing authority, or by having two individually new balancing authorities for each city. The study found that, whether Houma and Morgan City formed a new combined city balancing authority, or formed a sperate balancing authority for each city, the cities would have about the same level of transfer capability as they currently have as part of the LEPA balancing authority.

Houma and Morgan City were each also considering new in-city generation, and they tasked GDS to study and determine whether the new in-city generation would impact the ability of Houma and Morgan City to import power.

The study in the September 2009 GDS Report found that installing new generation within the cities would not negatively impact the cities' ability to import power. This is not as certain a conclusion as stated by ERG, who opined that 100 MW of CC in Morgan City and 40 MW in Houma would positively impact import capability.

The September 2009 GDS Report also found that the preferred site for new generation located near the cities depended on whether the generation would serve one, or both, cities. The preferred sites for serving both cities were Gibson 110 kV, Gibson 138 kV, and Ramos 138 kV stations. However, what is important to note is that the study found that multiple stations are capable of serving a Houma balancing authority. This is relevant because representations have been made that it was beneficial to Houma to site the LEPA-1 Unit at Morgan City and when asked for support for that representation this September 2009 GDS Transmission Assessment Report was cited. However, as UPC reads this report, the conclusion was that siting the generation nearer Morgan City was beneficial to the combined loads of Morgan city and Houma but did not provide any independent benefit to Houma. Considering the report showed no additional transmission constraints with closer siting to Houma, it is reasonable to assume that having the unit sited in Houma would have provided more reliability to Houma as opposed to having the unit sited in Morgan City.

Finally, UPC has concerns with the modeling used to produce the results of this and the following GDS reports. At the time of the study, the Entergy Construction Plan included the Acadiana Load Pocket Project ("ALP Project") which would have improved transmission constraints for Houma and Morgan City. However, GDS counteracted the benefits to be provided by the ALP Project in their model with an assumption that CLECO would cease operation of its Teche Generation Facility, which removed area generation in excess of 400 MW and replaced those MWs with significantly more remote generation located at the CLECO Evangeline Power Plant located in St. Landry Parish and Acadia Power Plant located in Mowatta, Louisiana. UPC cannot find where GDS provided any independent support for this assumption, nor can it find any public information supporting this assumption, and as of today over 360 MW of Teche generation remains.

The earliest public indication received from CLECO regarding any of the Teche generation that UPC can locate was in Cleco's 2015 Integrated Resource Plan, ("IRP") which stated that other than 15 MW of operating capacity of Teche 1, Cleco had no intention of retiring any of its other electric generating units located at Teche. Since the time of the study, Cleco retired the 15 MW of Teche 1 in 2016 and 34 MW of net capacity of Teche 2 in 2011. However, Cleco had just added 33 MW of blackstart generation at the Teche facility in 2011 based upon an application it filed at the LPSC in 2009. With regards to the most significant portion of the Teche generation, the 338 MW of Teche Unit 3, it remains operational until this day. While Cleco did consider a retirement of Teche Unit 3 in late 2016 by filing an Attachment Y, MISO promptly designated that unit as a SSR such that the unit could not be taken out of service until after completion of the Terrebonne - Bayou Vista transmission project. Now, in its latest IRP proceeding, CLECO announced that regardless of the completion of the Terrebonne - Bayou Vista Project it will not be seeking to retire Teche Unit 3 due to what it feels are unacceptable reliability risks to the area associated with such a retirement.

Because GDS included an assumption for the retirement of the Teche generating units eliminating benefits to be provide by the ALP Project, this study, and all studies moving forward, had their results negatively skewed, and UPC can find no information in the GDS reports or publicly that supports the assumption that Cleco had any intention of retiring those units. To the contrary, UPC's understanding of Cleco's 2016 decision to file an attachment Y was that decision was motivated by the manner in which MISO was dispatching the unit which was resulting in Cleco suffering losses because although Cleco was receiving uplift payments to cover the variable costs when dispatched, it was not receiving the fixed operating costs attributable to the periods the unit needed to stand ready.

Finally, in addition to a general concern that the unsupported assumption negated the benefits of the ALP, UPC notes that the Attachment Y process related to Teche Unit 3 highlights why Entergy and Cleco's entrance into MISO was a game changer with regards to transparency of how generator and transmission decisions would impact the system.

6. September 2009 GDS Report to Morgan City and Terrebonne Parish Consolidated Government: "Power Supply Feasibility Analysis" ("September 2009 GDS Power Supply Feasibility Analysis")

The cities of Morgan City and Houma also jointly retained GDS to conduct an initial power supply feasibility analysis on the benefits of *new generation* resources, as compared to the cities' existing gas-fired generation. The goal of this analysis was to utilize an economical dispatch model, combined with resource production cost data for alternative generation resources, to determine the optimal type and quantities of resources to serve the cities' supplemental demand and energy requirements. The study identified a potential opportunity to reduce the cities' overall incremental cost, because of the tradeoff between the maintenance cost, minimum run time, and dispatch cost of the cities' existing steam turbines, versus the same parameters for *new generation resource alternatives*.

As in the prior report, GDS further noted that the Entergy construction plan projected at the time and the Acadiana Load Pocket Project ("ALP Project") described in the "Transmission Assessment" report, prepared by GDS in September 2009, were expected to be complete by 2013, and were considered in their report, and therefore, GDS used the projected 2013 hourly load forecast for its study. However, GDS ultimately offset the advantages of the ALP Project by creating an unsupported assumption that Teche Generation would be retired resulting in the loss of generation in the load pocket. UPC cannot find where CLECO anywhere had publicly indicated an intention to retire any Teche generating units, and therefore, is unaware of the basis for the assumption used by GDS.

GDS's conclusion for the September 2009 GDS Power Supply Feasibility Analysis was that, based on the results of this economic feasibility study, there would have been potential savings for several scenarios of new peaking generation technologies, primarily the Solar Titan and Wartsila units. GDS further stated that, "[i]t is obvious that without a comprehensive (and prohibitively expensive) transmission solution, the Cities' will always have a requirement to generate power from internal system resources to reliably serve their load." While UPC does not opine as to the correctness of this statement, it does have concerns that this position of "prohibitive cost" was taken by both ERG and GDS in such a manner that a PPA with a transmission solution was never tested against the risky and potentially prohibitively expensive new build scenarios to prove the proposition correct. In fact, despite GDS's conclusory position that transmission costs were prohibitive, GDS actually also espoused the same need for a comparison. The September 2009 GDS Power Supply Feasibility Analysis concluded with the statement,

> The Cities' will have to compare the long-term benefits of owning new generation resources versus their expected capital outlays and useful life of the existing steam turbines. In addition, the Cities will need to determine how the economic benefits of new peaking resources compares to other available purchased power alternatives (that would also require the Cities to maintain their existing generation).

Because the September 2009 GDS Power Supply Feasibility Analysis concluded that other studies would be necessary, the value of this study appears to be extremely limited. The most important observation from the September 2009 GDS Power Supply Feasibility Analysis seems to be that, based at least partly upon the inaccurate assumption related to Teche retirements, the proclamation that, due to the cities' import capability of economical market purchase to approximately 50 MW, the combination of Houma and Morgan City were, thus, required to serve approximately 50-60 MW of load with their collective existing gas steam turbines. This assumption is used in all future reports of GDS and this assumption is in direct conflict with the initial rationale for needing new generation, and that was to reduce the need for dispatching the more expensive legacy peaking generation.

7. January 2010 GDS Report to Houma and Morgan City: "Power Supply Feasibility Analysis" ("January 2010 GDS Report")

For the January 2010 GDS Report, the Houma and Morgan City retained the services of GDS to:

1. Determine the optimal economic project participation in *LEPA's proposed combined-cycle and combustion-turbine peaking facilities*;
2. Evaluate Morgan City and Houma's power supply cost operating as independent balancing authorities and also as a combined system, including optional retirement of native resources and additional new generation resources.

The January 2010 GDS Report concluded that there were *potential* savings for the cities, if certain types of new generation resources were pursued and/or combined with continued operation of select Houma units. GDS found that, while LEPA's original proposal did not indicate that the cities would achieve any savings from a one-year snapshot, there was some potential for a variation on the LEPA proposal, whereby the cities could utilize the proposed combined-cycle unit with existing steam-turbine generation. GDS stated that, in order for the cities to finalize a plan of action to reliably serve their future load requirements, several steps need to be taken. These steps are summarized below.

> 1. Prepare an engineering estimate of the capital cost and maintenance required to extend the useful life of the cities' existing steam-turbine generation so that a better economic comparison can be made between the "Base Case" scenario and the alternative generation scenarios;
>
> 2. Request that LEPA update their proposed combined-cycle project for the latest construction cost, adjustment to operating parameters, and possibly a reconfiguration that would reduce the size of the facility, but not to a point where the operational efficiencies are degraded. It may be possible to reduce the overall cost of LEPA's proposed project where it provides more benefits for the Cities;
>
> 3. Develop a RFP to request bids from EPCs for peaking generation alternatives that include Solar Turbine 130 units, Wartsila's 8.5 MW units, or some similar reciprocating/microturbine resources that have similar operating characteristics. It will be important to verify the actual construction cost and specific operating parameters in the southern Louisiana area; and
>
> 4. Develop a comparison of any known purchased power alternatives that could supplant the need to run the cities' existing steam-turbines, or limits their operation, and perform an economic comparison to the self-build opportunities discussed in the study.

It is interesting to note that once again GDS did in fact propose that a prudent step would be to include an analysis of purchased power alternatives, as well as, to perform an economic comparison of those to the self-build opportunities. UPC cannot find where that step was ever taken in any meaningful fashion.

8. July 2010 GDS Report to Houma: "Power Supply Feasibility Analysis of Participation in LEPA's Generation Project" ("July 2010 GDS Report")

Following the January 2010 GDS Report, LEPA and its members engaged in a dialogue on how best to meet the members' future capacity deficiencies, and what other options were available to meet those needs. As a part of this process, LEPA reassessed its members' overall future power requirements, evaluated smaller combined-cycle generation alternatives, and developed a revised power supply portfolio that included incremental additions of distributed peaking generation for meeting future deficiencies. As part of LEPA's reassessment, Houma requested that GDS perform an economic generation feasibility study to determine Houma' s optimal participation in LEPA's proposed combined-cycle generation project and distributed peaking generation project(s).

UPC notes that despite GDS's recommendation earlier in 2010 of comparing new generation options against purchased power alternatives, that the July 2010 GDS Report, by defined scope, was limited by Houma to only analyzing LEPA's alternatives; and therefore, indicates that Houma had already narrowed its only remaining decision to not whether to engage in new generation, but rather, what levels of participation it should engage in LEPA's proposed CC and CT.

This July 2010 GDS Report reiterated that, as was discussed in more detail in the Transmission Assessment, prevailing transmission constraints during the summer months would limit Houma's combined import capability of economical market purchases to approximately 20-30 MWs, and this situation was not expected to improve even after the completion of the ALP Project in 2012. However, as discussed in UPC's earlier review of the GDS Transmission Assessment, this conclusion was based on the faulty assumption that Cleo would retire Teche Generating Units. Based on its assumptions, GDS assumed for this study that the Houma would continue to have a requirement to serve, at a minimum, approximately 50-60 MWs of load with some form of internal generation, either new generation or Houma's existing natural gas steam turbines, during the summer months, and have enough firm capacity to meet their total load requirements, including reliability planning reserve requirements, of approximately 102 MW.

This July 2010 GDS Report is the first report where the conclusion was not limited by the need for further study and there are several assumptions that were used that are important to note.

The prior GDS reports were caveated that there was no assumption included for the cost of capital improvements to the Legacy Units, and that was a limiting factor to those studies. This July 2010 GDS Report, however, did estimate that the cost for capital improvements to extend the life and increase the reliability of the existing steam turbine generation was approximately $10.4 million.[43] The July 2010 GDS Report also assumed that Houma would continue to spend $2.5 million, per year, in fixed operations and maintenance expenses (or a pro-rata allocation for maintaining fewer units) for all scenarios involving the existing steam-turbine generation. It is important to note that UPC has held discussions with the finance and utility staff of Houma and cannot find any support for the assumption of a pro-rata reduction in fixed operations and maintenance expenses as there is no relative savings generated as between running one unit or three units. Houma needs to staff and

[43] This is the same amount that was estimated by URS in 2009.

electrical utility department whether there are one, two or three units running and there is no pr rata reduction in staffing related to partial retirements of the units.

The July 2010 GDS Report maintained the assumption that the Rodermacher and SWEA generation would remain constant. Accordingly, as the July 2010 GDS Report considered an optimal equipment selection, it considered that Houma's supplemental deficiency requirement of up to 76 MW of capacity and associated energy (excluding purchases from the market) would fit the dispatch profile for a mix of intermediate and peaking units. The July 2010 GDS Report evaluated the economic benefits of participating in LEPA's proposed combined-cycle and potential peaking generating units, and it determined the optimal level of participation, versus maintaining the status quo.

The July 2010 GDS Report base case assumed that the selected resources would be available to operate year-round.

An extremely troubling assumption was that the "base case" scenario further assumed that Houma would have to rely only on its existing and proposed new generation resources to meet all of its power requirements year-round. That is, the July 2010 GDS Report base case assumed no economic energy purchases were to be available from the market. UPC notes that assuming no economic purchases in the base case was a historically inaccurate constraint, and extremely bias to the outcome of new generation vs. existing generation. In 2007, according to the 2008 GDS study, Houma was acquiring over 50% of its energy from economic market purchases. To limit the GDS "Lowest Annual Power Cost" base case analysis, with the restriction of an island approach, with no market purchases, provided a fictitious result of little value, because Houma had been and never would be dispatched as an island with only its own generation to serve its load as this assumes, especially inside of MISO. UPC does note that this July 2010 GDS Report at least provided a sensitivity where this constraint on market energy purchases is released. As one would expect the more realistic assumption produced much lower projected savings, and it is UPC's opinion that this sensitivity would have been more appropriate for use as the base case.

After the July 2010 GDS Report explained the above assumptions and constraints, as well as, other assumptions used, it then provided GDS' analysis of the optimal participation, as between a CC intermediate load unit and a CT peaking load unit. The July 2010 GDS Report does this by first designing an optimal mix of base/intermediate/and peaking from scratch, and then making adjustments related to the current portfolio and what was available for retirement. This analysis concluded that 25 MW was identified in the load duration curve analyses as the optimal amount of an intermediate resource, but the study states that still needed to be verified by evaluating several combinations of CC alternatives using the economic hourly dispatch model to determine the lowest overall power cost to Houma. This exercise produced the following chart.

Base Case Optimization Results		
#	Generation Configuration Scenario	Annual Power Cost ($000)
1.	25 MW CC/ 15 MW CT/ 39 MW ST	$27,613
2.	25 MWCC/0 MW CT/ 51 MW ST	$27,845
3.	20 MW CC / 15 MW CT/ 51 MW ST	$28,102
4.	30 MW CC / 30 MW CT/ 25 MW ST	$28,165
5.	30 MW CC / 45 MW CT/ 0 MW ST	$28,276
6.	30 MW CC/ 0 MW CT/ 51 MW ST	$28,369
7.	20 MW CC/ 60 MW CT/ 0 MW ST	$29,328
8.	20 MW CC/ 0 MW CT/ 64 MW ST	$29,344
9.	0MWCC/0MWCT /76MW ST	$30,652
10.	0 MW CC / 45 MW CT/ 39 MW ST	$31,049

Table 5 - Annual power cost for various resource configurations

The July 2010 GDS Report concluded that, based on an average weighted distribution of the scenario rankings, the resource configuration that provides the most value to Houma is 25 MW of LEPA's proposed combined-cycle resource, 15 MW of peaking generation, and 39 MW of Houma's existing steam turbine generation. Using the same criteria, the next best generation alternative is the 25 MW of LEPA's proposed combined-cycle resource and 51 MW of Houma's existing steam-turbine generation.

However, as mentioned above, UPC believes this analysis and chart based on the proposed base case is of limited value, due to its assumption that the costs included in each of the scenarios are derived from Houma's load being met solely with the cost of dispatch of its expensive Legacy Units and not having any availability to market energy purchases, which as discussed previously, is not a realistic scenario.

Also, as mentioned earlier, the July 2010 GDS Report provided a sensitivity analysis, which released that "island approach" assumption and included the more realistic assumption of energy market purchases and below is the result.

1.	25 MW CC / 0 MW CT/ 51 MW ST	$26,533
2.	25 MWCC/ 15 MWCT /39MW ST	$26,832
3.	20 MW CC/ 15 MW CT/ 51 MW ST	$27,165
4.	0 MW CC/ 0 MW CT/ 76 MW ST	$27,354
5.	20 MW CC/ 0 MW CT/ 64 MW ST	$27,607
6.	30 MW CC / 0 MW CT/ 51 MW ST	$27,751
7.	30 MW CC / 30 MW CT/ 25 MW ST	$27,973
8.	20MWCC/60MWCT /0 MW ST	$28,172
9.	0 MW CC / 45 MW CT/ 39 MW ST	$28,317
10.	30 MW CC / 45 MW CT/ 0 MW ST	$28,501

What is of note between these two charts is that in the unrealistic base case of the report, the savings that could be generated between the Scenario # 1 alternative of retiring two Legacy Units and acquiring both a new 25 MW CC and a 15 MW CT, and Scenario #4 of just maintain the current Legacy Units is over $3 million per year. However, with the more realistic comparison, which assumed market energy would be procured, that difference shrank to approximately $800,000 per year, a reduction of approximately 75% of the projected benefits of the base case. Further of note, those lower projected benefits have been further reduced by the reduction in gas prices that has occurred since these studies were completed. The low gas case sensitivity provided in the July 2010 GDS Report in and of itself independently decreased that gap to around $800,000 as well. So, considering that the recent gas prices have been closer to the low gas case sensitivity, it is not hard to imagine that the combination of the realistic inclusion of market energy and the use of lower gas prices wiped out any projected savings that this report's base case projected, and that is just based on the assumptions of how those modeled units were to perform in the study. As will be discussed later, actual performance has lagged far behind the projections used in this study and have made a bad situation even worse.

It is also important to note that by including in its recommendation the retention of 39MW of Houma's existing steam turbine units in the optimal portfolio, GDS's in effect was recommending the retirement of 37 MW of Legacy Units, which Houma did not follow.

9. November 2012 GDS Report to Houma: "Power Supply Feasibility Analysis of Participation in LEPA's Generation Project" ("November 2012 GDS Report")

After the July 2010 GDS Report, in the Fall of 2010, Houma agreed to proceed with the development and construction of a 65 MW combined-facility which would be located near Morgan City, LA. The November 2012 GDS Report states:

> *Houma's July 2010 Feasibility Study recommended that Houma's optimal generation combination of new generation capacity was 25 MW of combined-cycle capacity and 15 MW of peaking capacity. However, LEPA was only committing to the development of a new combined-cycle generation facility and thus, Houma did not pursue an independent development course for a 15 MW peaking facility but instead continued to rely on its existing, steam-turbine generation to meet its peaking power requirements.*
>
> *Houma has initially committed to a 22 MW equity participation in LEPA's proposed 65 MW combined-cycle facility, however since 2010 there have been several material changes in the electrical industry...*
>
> *In light of these new externalities[44] and Houma's decision to develop/own 22 MW in a combined-cycle facility, Houma requested that GDS review the original July 2010 feasibility study and conduct a new assessment to determine if the 22 MW combined-cycle ownership option and the 15 MW peaking generation participation recommendations are still viable. Specifically, the City has retained the services of GDS to:*
>
> *(1) confirm the optimal economic project participation in LEPA's proposed 64 MW combined-cycle and potential peaking generation facilities using the current outlook for natural gas prices;*
>
> *(2) assess the impact of Houma's decision to participate in new combined- cycle and peaking generation in MISO's RTO market and identify any other alternatives that may be available to Houma in the MISO market.*

As discussed in the July 2010 GDS Report, in relation to the first scope matter, to confirm optimal participation, GDS ranked various base case scenarios according to "Lowest Annual Power Cost"

[44] GDS explained that the externalities were lower gas prices, entry into MISO and LEPA beginning an evaluation for new peaking generation capacity.

assuming an "island dispatch approach", meaning that only Houma's units were assumed to be dispatched to meet Houma's load. This remained an assumption in the November 2012 GDS Report, which continued to inaccurately represent actual experience. The November 2012 GDS Report evaluated the economic benefits of participating at various sizes of LEPA's proposed combined-cycle and potential peaking generating units as compared to dispatching only Houma's Legacy Units to meet that load need.

The November 2012 GDS Report indicated that the units to be used in this analysis would be a combined cycle resource based on a Siemens SCC-700 unit and a peaking generation based on a Solar Turbines' Titan 130 unit. Generation cost and operating information provided by LEPA at Operating Committee and Board Meetings is shown below in table from the 2012 Updated GDS report:

LEPA Generation

Category	Units	Siemens SCC-700	Solar Turbines Titan 130
Technology		Combined Cycle	Small Gas Turbine
Size	MW	63.5	14.5
Capital Cost	$/kW	2,125	839
Life of Unit	Years	30	30
Heat Rate	Btu/kWh	7,985	11,341

Two notable entries in the this GDS table are the capital cost per kw, $/kw, of $2125 and (2) the heat rate of 7.985 MMBtu/Mwh.[45]

1. UPC notes that a capital cost of $2,125 $/kW is high, relative to other CC units that have been on the market. A moderate sized CC of 500 MW has an installed capital cost of approximately $1,200 to $1,300 per kW. Used CC units have been on the market at around $500 $/kW.[46] It is not known if PPAs accessing less expensive CC units were available at the time of the 2010 decision.

[45] This was a cost estimate done in 2012. The actual cost was slightly less.
[46] *See* Entergy Newsroom, *Entergy Corporation Subsidiaries Close Transaction to Buy Union Power Station*, (March 04, 2016) (For example, the Union Power Station acquired by ELL was priced at approximately $480/kw in 2015.).

2. The original design heat rate of 7.985 MMBtu/Mwh for LEPA-1 is higher than large CC units that have recently or will shortly be entering into the MISO market. New units have a heat rate of 6.4 MMBtu/Mwh. Older large units, such as Union Power Station and Cottonwood have heat rates around 7.2 MMBtu/Mwh. In the MISO day ahead market, these units can be the marginal unit driving the LMPs. For example, a 7.2 MMBtu/Mwh heat rate unit, with $3.00 per MMBtu natural gas, and a $2.50 variable O&M costs would have an energy cost of $24.1 $/Mwh. The LEPA-1 unit at its original design heat rate, with the same cost assumptions would have a cost of $26.5 per Mwh. The actual heat rate in 2016, 8.7 MMBtu/Mwh, would have an operating cost of $28.6 per Mwh under these assumptions.

Further, in the November 2012 GDS Report, it was continued to be assumed that the Houma Legacy Units would require $10.4 million in capital improvements to extend the useful life, and increase the reliability of the existing steam-turbine generation (or a pro-rata allocation for maintaining fewer units under certain scenarios), and would also continue to spend a combined $2.5 million per year in fixed operations and maintenance expenses (or a pro-rata allocation for maintaining fewer units) for all scenarios involving the existing steam-turbine generation.[47] As noted in UPC's analysis of the July 2010 GDS report, there does not seem to be any support for the rationale of a pro-rata reduction in operations and maintenance expenses based on partial retirements of units.

The expected life of the proposed new generation resources was assumed to be 30 years.[48] As was the case with the July 2010 GDS Report, what is not clear from the November 2012 GDS Report is what the extended useful life of the Legacy Units was expected to be as a result of the projected $10.4 million in upgrade investments. However, considering there is an acknowledgement in the November 2012 GDS Report that the investment was for the purpose of extending the useful life, and further considering the premise of the November 2012 GDS Report was to compare the option of keeping the Legacy Units in service vs. investing in 30 year new generation, it seems safe to assume the investment would have extended the useful life for at least 10 to 15 years, if not more, but this is merely an assumption.

The July 2010 Original GDS Report recommended that Houma's optimal generation combination of new generation capacity was 25 MW of combined cycle capacity and 15 MW of peaking capacity

[47] 2012 Updated GDS Report, at 4.
[48] 2012 Updated GDS Report, at 4.

(see first column of table below). The November 2012 GDS Report also ranked the 25 MW of combined cycle capacity and 15 MW of peaking capacity as the "Lowest Annual Power Cost" (see second column in the table below).

Base Case Optimization Results					
	Generation Configuration Scenario	Jul. 2010 Annual Power Cost		Nov. 2012 Annual Power Cost	
		Rank	($000)	Rank	($000)
1	25 MW CC / 15 MW CT / 39 MW ST	1	$27,613	1	$25,198
2	25 MW CC / 0 MW CT / 51 MW ST	2	$27,845	2	$25,560
3	20 MW CC / 15 MW CT / 51 MW ST	3	$28,102	3	$26,072
4	30 MW CC / 30 MW CT / 25 MW ST	4	$28,165	4	$26,179
5	30 MW CC / 45 MW CT / 0 MW ST	5	$28,276	6	$26,325
6	30 MW CC / 0 MW CT / 51 MW ST	6	$28,369	5	$26,283
7	20 MW CC / 60 MW CT / 0 MW ST	7	$29,328	8	$27,437
8	20 MW CC / 0 MW CT / 64 MW ST	8	$29,344	7	$27,271
9	0 MW CC / 0 MW CT / 76 MW ST	9	$30,652	9	$28,651
10	0 MW CC / 45 MW CT / 39 MW ST	10	$31,049	10	$29,457
	Gas Price Assumption	*$7.00/MBtu*		*$5.87/MBtu*	

The November 2012 GDS Report came to the following updated conclusion,

> *As was concluded in the original July 2010 Feasibility Study, the resource configuration that provides the most value to Houma is 25 MW of LEPA's proposed combined-cycle resource, 15 MW of a potential peaking generator, and continued utilization of Houma's 39 MW existing steam turbine generation. Deviating from the 25 MW of combined-cycle generation alternative results in greater volatility in Houma's total power cost under these various sensitivities.*

As discussed in the July 2010 GDS Report, only 39 MW of the Legacy Unit capacity of the 76 MW of then-currently-owned-and-operated Legacy Units was retained under the GDS preferred portfolio. Further note that GDS' recommendation, thus, included a recommendation to retire 37 MW of the Legacy Units, which intuitively can be assumed to be the approximate 12 MW of Unit #14 and the approximate 27 MW of Unit #15. However, UPC wishes to note that it has not been able to locate any analysis to support why from a long-term reliability perspective Units #14 and #15 were recommended to be retired. Nor, in the alternative, has UPC been able to find any support as to why

Unit #16 could economically remain in service. Ideally, if there was a general concern that all of the Legacy Units were aged, and at risk of unexpected loss of service, then it seems there should have been some analysis as to why some units could have had their life economically extended, and why other units should have been retired.

UPC acknowledges that, while the analysis performed by GDS of the "Lowest Annual Power Cost" does support the preferred generation portfolio recommended by GDS, UPC once again has concerns about the analysis itself for the purpose for which it was used. First, as mentioned earlier, the scope of the July 2010 GDS Report limited the comparison to only comparing the current Legacy Units against "new generation" alternatives. Therefore, other than a cursory reference to studies and/or analysis done in the past by LEPA, UPC has not found any analysis supporting the assumed proposition that new generation was a least cost alternative when compared to purchased power with transmission upgrades. While it very well may have been, without true market testing it is an unknown.

Second, the "Lowest Annual Power Cost" base case represents a fiction which assumes no market purchases would be available. This is not what has happened historically, nor would it be expected to happen prospectively, especially in relation to the November 2012 GDS Report, which occurred at time when it was acknowledged that LEPA-1 would be in MISO. At the time of the July 2010 GDS Report, a sensitivity analysis was run, including market energy costs, which illustrated the dramatic effect energy market purchases produced on the difference between options. However, GDS did not perform that same sensitivity for the November 2012 GDS Report. One would expect that as in the July 2010 report the projected savings would have been materially diminished, in fact the effect would be severely exacerbated by the access for Houma to lower cost energy that the MISO energy and ancillary market was to provide. In fact, since Considering this monumental change in how generating units would be dispatched, it seems as if the "Lowest Annual Power Cost" analysis assuming full dispatch of all of Houma's units is of very limited value, if any. The result of the second assigned tasks confirms that proposition.

The second tasks assigned to GDS for the November 2012 GDS Report was:

> *(2) assess the impact of Houma's decision to participate in new combined- cycle and peaking generation in MISO's RTO market and identify any other alternatives that may be available to Houma in the MISO market.*

Before reviewing the economic analysis provided with regard to LEPA-1's participation in the MISO market, some of the data included in the November 2012 GDS Report would seem to have raised more fundamental concerns over continuing with the project at such a fast pace prior to taking a hard look at the fundamental changes provided by MISO. If the need for Houma to acquire new generation was based on the concern of an unexpected loss of a Legacy Unit, then there seems there should have been some consideration for the advantages to be provided with the introduction of the MISO capacity market.[49] At the time of the November 2012 GDS Report it was acknowledged that Capacity prices in MISO-North had averaged between $0.05/kw-month and $1.00/kw month, and were expected to remain low for the near-term. Approximate with the time of the bond issuance, the MISO South held its first auction which yielded prices that Houma could have participated in of $16.44 $/MW-day.[50] This value converts an annual cost of $6.00 $/kw-year. This cost can be compared to the levelized annual cost of $195.70 $/kw-year for a generator costing approximately the LEPA-1 cost of $1,962 $/kw of installed capital costs. If Houma's decision to invest in LEPA-1 was driven form a concern over an unexpected capacity shortage in the event of unexpected outages of the Legacy Units, then the MISO capacity auction provided low-cost, near-term alternatives to potentially address this concern. While reliance on MISO's Planning Resource Auction may not be an optimal long-term solution for Houma to be able to address its long-term capacity needs, it was and is available to serve near-term needs to allow long-term needs to be assessed once a need actually arises.[51]

Further, with the added independence and transparency that MISO was to provide, and considering it had been years since the original decision to invest in LEPA, and further, that decision process was premised on 140 MW of local generation alleviating transmission constraints which would not be accomplished with LEPA-1, and even further considering the directive in the scope of this November 2012 GDS Report included a directive to identify other alternatives available to Houma in the MISO market, it seems like 2012 would have been the appropriate time to truly market test the proposition that the proposed new LEPA generation was a more economical option than purchased power with transmission upgrades. However, UPC has been unable to find any analysis in this regard.

[49] *See* 2012 Updated GDS Report, at 9.
[50] *See* MISO 2014/2015 MISO Planning Resource Auction, (April 14, 2014).
[51] UPC notes that based on materials it has seen that LEPA has essentially utilized this approach on behalf of Plaquemines and Morgan City by retiring their legacy units and acquiring needed capacity from Houma's excess generation and others at PRA equivalent prices.

With regard to the November 2012 GDS Report economic analysis of the recommended portfolio's performance in MISO, a full review of the analysis actually shows that Houma was projected to experience negative cashflow from its investment GDS's recommended portfolio of adding 22 MW of CC and 15 MW of CT, while retiring 37 MW of Legacy Units.

One warning sign from this analysis that UPC identified is that, although the 2013 Consulting Engineer's assumed a 74% capacity factor[52] for the CC and the "Lowest Annual Power Cost" analysis assumed 100% dispatch of the CC, the MISO market simulation predicted only a 22% capacity factor for the CC.

However, the most concerning finding is that the MISO economic analysis actually shows that Houma was expected to experience negative cashflow from its investment into the new preferred portfolio. Houma did not need the capacity. Therefore, the decision to invest in new generation was an economic decision, meaning the investment needed to be supported with projections that Houma would experience energy savings greater than the fixed capital and operating costs it would incur from investing in the new generation. The November 2012 GDS Report actually supported the exact opposite conclusion and that is, that Houma was projected to incur more fixed costs from its investment in the generation than it would experience in energy savings,

The MISO economic analysis showed that Houma's savings were only projected to be $755,000 per year, and under the low gas case scenario, those savings were projected only to be $370,000 per year. But, those are just the energy savings that would have to be compared against the costs associated with Houma's investment in 25MW of CC and 15MW of CT. Costs which include: (1) over $2.2M in Debt Service for the CC alone; plus (2) $1.1M in fixed operating costs for the CC; plus (3) $250 thousand in LEPA administrative and general charges; plus (4) approximately $1.5M in debt service and fixed operating costs for the CT[53]. That totals over $5.M in new costs as compared to an at best projected amount of energy savings of $755,000. And, while these fixed cost may have been projected to be somewhat offset from avoided costs associated with the retirement of 37 MW of Houma's retirement units, there are three issues with that assumption: (1) 37/76 of the projected

[52] *See* 2013 Consulting Engineer's Report, Paragraph d. at B-32.
[53] Estimate derived from the July 2010 GDS Report Appendix A.

$2.5M of total cost would only be a $1.2M[54] offset against the over $5M in costs; (2) the assumption that the $1.2M in avoided costs would materialize is flawed in that Houma does not believe that there would be such a pro rata savings from partial retirement of units; and (3) as attested to by Mr. Tom Bourg at the July 26, 2010 TPCG Council meeting, Houma never intended on following that recommendation and planned on keeping those units available. UPC found the projected negative cashflow to be such a troubling observation that UPC asked GDS to confirm if it was interpreting the data correctly. Below is the question and answer:

> Q. Please confirm that TPCG is correct in its understanding of the expected cashflow that was to be expected from the recommended portfolio in MISO based upon the results of the MISO analysis contained in Section 3.3 of the November 14, 2012 GDS Updated Power Supply Feasibility Analysis of Participation in LEPA's Generation Projects (the "GDS November 2012 Report"). To the extent any of TPCG's understanding provided immediately below is incorrect please explain and describe in detail what is incorrect about the understanding.
>
> The GDS November 2012 Report projected Base Case Total MISO Market Benefits of $755,000 to be generated from the recommended portfolio of 22MW of new CC, 15 MW of new CT and continued utilization of 39MW existing Steam Turbine.
>
> The $755,000 of Total MISO Market Benefits did not account for any of the fixed costs of acquiring or operating the new Generator. Therefore, to determine the projected total cashflow impact to Houma from the recommended portfolio, the $755,000 of projected Total MISO Market Benefits would need to be combined with the other projected cashflow impacts as follows:
>
> 1. The projected fixed cost of acquiring the new generation, primarily including the annual debt service that would have to be paid to support the financing of the generation.
>
> 2. The projected annual fixed cost of operations and maintenance expenses associated with the new units including costs of the LTSA, Insurance, Property lease, etc.
>
> 3. The projected avoided cost savings from avoiding capital expenditures to the Houma steam units based upon a 37/76 pro rata portion of the $10.4M in projected capital improvements to the Houma steam Units.
>
> 4. The projected avoided cost savings from avoiding fixed operations and maintenance expenditures on the Houma steam units based upon 37/76

[54] The July 2010 GDS Report Appendix A indicates the savings would be slightly higher amount of approximately $1.7M.

pro rata portion of the $2.5M in projected fixed operations and maintenance expenses.

5. The additional administrative costs of LEPA associated with the new generation.

A. Regarding your June 3rd questions, I reviewed a few documents and yes, I am confirming that TPCG's outline of the total cost of the "recommended portfolio" is correct. Combining the net market benefits with the other expenses would generate the total expected cost of the portfolio.

Ultimately, what the MISO analysis from the November 2012 GDS report shows is that Houma did not need capacity, but yet invested in generation projected to deliver net losses.

Further, even the projected $755,000 projection has been shown to be materially overstated. Included within that $755,000 of savings is a projected amount of $312,000 of FTR Value. FTR stands for Financial Transmission Rights and is representative of payments that are made to load who have historically contributed to the usage of a particular transmission segment. Congestion revenues are used to pay the holder of FTRs with the general theory being that a load pays for the congestion component of the LMP, but to the extent it has historically contributed to that line, it can get most of that cost back through FTR revenues for any FTRs it holds. UPC asked GDS to support how it derived its estimates of FTR Value and GDS responded:

A. The $312,000 and $139,000 estimates of FTR benefits were based upon output generated from the PROMOD commercial modeling software. PROMOD generated hourly LMPs for the LEPA-1 project, anticipated LEPA-1 generation, as well as the projected LMPs for Houma's load node. Based upon the assumption that LEPA would acquire an ARR for the LEPA-1 project, GDS calculated the FTR benefits based upon the difference between the congestion components of the LEPA-1 CC LMP and the Houma LMP. The actual calculation used in the study was the difference between the average Houma Load LMP (i.e. $43.6/MWh in the base gas case) and the average LEPA-1 CC LMP (i.e. $41.8/MWh in the base gas case), multiplied by 22 MW and 8,760 hours per year. GDS assumed a 90% funding of the FTRs so multiplying the FTR benefit of approximately $346,900 by 90% yields the $312,000 used in the November 2012 report and the presentation.

According to information provided by LEPA, actual FTR revenues for 2017 and 2018 were $1,790 and $11,884 respectively. UPC recommends that Houma investigate what Auction Revenue Rights were acquired by LEPA for the LEPA-1 project and why the assumed revenues were so materially overstated.

The November 2012 GDS Report is the last report issued prior to Houma's final commitment to proceed with LEPA-1. GDS's updated conclusions in the November 2012 GDS Report were:

> (1) *Based on the results of this updated feasibility study, Houma should proceed with the 22 MW equity/ ownership participation in LEPA's proposed combined-cycle project. In conjunction with the combined-cycle project, the potential for 15 MW of peaking generation ownership provides the greatest economic and operational benefits to Houma under various gas price contingencies and the pending transition to the MISO market. The addition of these two resources will also contribute to a more diversified and optimal long-term generation resource portfolio and allow Houma to meet its near-term capacity requirements.*
>
> (2) *In addition, these MISO market benefits are understated because they only account for "Day-Ahead" participation in the energy markets. Promod does not have the ability to capture "Real-Time" benefits nor potential ancillary benefits, such as opportunities to submit bids for spinning and regulation or respond to "Real-Time" dispatch requests from MISO. The primary benefit of the Promod analysis is to determine the competitiveness of new generation facilities and to assess potential exposure for load-serving entities with and without new resources. In addition, the LEPA combined-cycle facility guarantees that Houma's MISO market exposure related to the portion of Houma's load requirements served by the combined-cycle will be hedged at the combined-cycle's variable cost. This is due to the fact that Houma/LEPA can always "self-schedule" the combined-cycle resource and avoid purchasing load requirements from the MISO market at the prevailing LMP prices. This intangible benefit is difficult to quantify with any certainty but the ability to hedge the LMP exposure is certainly significant.*

UPC acknowledges that GDS' scope for the November 2012 GDS Report assumes a need for new generation, as well as, that GDS' fully disclosed all of the assumptions it used in generating its results and all of the results from its MISO analysis. However, UPC is concerned as to whether that scope was the most thorough that should have been performed considering the introduction of MISO into the region.

Houma was not in need of new generation, unless there was an assumption that one or more of the Legacy Units were unexpectedly to go out of service, with no opportunity for replacement. Any concern regarding a unit unexpectedly going out of service likely could have been addressed with the introduction of MISO's short-term PRA capacity markets providing short to intermediate-term access to economic capacity, to allow Houma to address an unexpected outages when such an issue arose.[55]

Further, UPC finds that the results from the limited MISO economics analysis that was done actually projected that Houma was expected to experience a net loss from the investment into generation it did not need. Making matters worse, while Houma did make the costly investment into LEPA-1, it did not retire any of the Legacy Units. By investing in LEPA-1 and not retiring any of the Legacy Units, Houma destined itself to pay a very high price for the new LEPA-1 unit as an extremely expensive insurance policy, while generating no savings form the retirements of any of the Legacy Units. Finally, by Houma not retiring its legacy units, those units continue to provide reliability in the region that the other members of LEPA were able to capitalize on by retiring their own inefficient legacy units and currently replacing that capacity with the cheap capacity from the PRA and from Houma and/or others at PRA like prices. Meanwhile, Houma is paying the high price of LEPA-1 for generation it does not need for capacity, while it continues to maintain its legacy units, and in return, is only receiving the deeply discounted MISO PRA prices for its excess generation resulting from its expensive investment into LEPA-1.

[55] With LEPA/Houma joining MISO, Houma currently could procure short term generation at the current price of $10/MW Day from the MISO Planning Resource Auction ("PRA"), while it planned a longer-term replacement.

V. Development, Design, Construction and Operation Issues Surrounding LEPA-1

The Decision to invest in LEPA-1 was a decision to allow LEPA to develop, design, construct, and operate a 64 MW nominal rated combined cycle combustion turbine electric generation unit. UPC is not aware of any similar experience that LEPA may have possessed in designing and constructing such a generating unit. As can be evidenced by the multi-million-dollar disallowances ordered by the Louisiana Public Service Commission on Entergy's Waterford 3 construction project and SWEPCO's Turk Plant construction project, the designing and construction of generating units is a very risky enterprise. In both of those cases, the units were being built by investor owned utilities, where investors would take the risk of cost overruns and faulty design and construction. The construction of the LEPA-1 unit by LEPA did not provide any investor party to absorb these risks, instead leaving all of those risks to fall on the participating members.

Further, it appears as if that risk was intensified by LEPA's decision to separately contract for procurement, design, and construction. Instead of engaging in a single design-build contract, where there would be one party solely responsible for engineering, procuring, constructing, and delivering the project on time and on budget, LEPA bifurcated its approach to contracting with multiple vendors and contractors. This bifurcated approach to contracting has resulted in multiple parties pointing fingers at one another to place the blame for the late and cost over-run project, which project also does not meet projected specifications.

The schedule was developed by LEPA's "Design Engineer", Burns & Roe Enterprises, Inc. and was based on the procurement by LEPA of the major equipment, followed by the award of an engineering, procurement and construction contract ("EPC Contract") to procure the remaining balance of plant equipment and materials, design and construct the project. Accordingly, major equipment was procured by LEPA, and not the EPC contractor, including the gas turbine generator, steam turbine generator, heat recovery steam generator, and generator step-up transformers. The EPC Contract was designed to require the contractor to: (i) design, engineer, procure, construct, start-up, and carry out tests on LEPA Unit No. 1; and (ii) manage, supervise, inspect and furnish all labor, equipment, contractor equipment, temporary structures, temporary utilities, products and services for the foregoing, all on a turnkey basis, in accordance with the EPC Contract, including without limitation, the Project Schedule and the Scope of Work (as such terms were defined therein). The contractor was required to perform the work and turn over to the Authority in a manner that was sufficient, complete and adequate in all respects necessary to successfully achieve commercial operations by October 13, 2015 (the "Guaranteed Commercial Operation Date"). The EPC Contract was also expected to contain provisions that if the contractor failed to achieve commercial operations by the Guaranteed Commercial Operation Date, it would be required to pay liquidated damages, subject to certain conditions and limitations.

Construction delays and cost overruns did in fact occur, and, because the process was bifurcated between a Design Engineer, several equipment vendors, and an EPC contractor, no party retained the sole responsibility of those delays and cost overruns. The Robbins and Morton Group ("R&M") was the EPC contractor, and they alleged that the cause of these overruns was due to:

> *The delay to Commercial Operation was the result of the combined impact of numerous events of delay and disruption caused by LEPA, LEPA's equipment suppliers, and by Force Majeure weather events. These delays extended the Project by 295 calendar days. These delays and disruptions were caused by, without limitation: (a) The need to revise the deficient design by LEPA's engineer of the Administration Building, (b) Latent subsurface conditions, (c) Numerous design and fabrication defects in the Heat Recovery Steam Generator supplied by Victory Energy, LEPA's major equipment supplier, (d) Design and fabrication defects in equipment supplied by other LEPA equipment supplies, including General Electric and Siemens, € L'PA's insistence on steam quality standards in excess of Contract requirements, (f) Failure of LEPA to provide necessary technical assistance from its equipment supplier Siemens, and (g) Wrongful suspension by LEPA of ongoing reliability testing by R&M.*[56]

LEPA claimed that, throughout the construction of the project, it observed construction and commissioning delays it believes are attributable to R&M, but it acknowledged that R&M had submitted to LEPA notices of purchaser caused delays related primarily to the major equipment purchased by LEPA. On April 18, 2016, R&M submitted to LEPA a Request for Equitable Adjustment to Contract Time and Contract Price ("R&M Claim"). As described above, the R&M Claim suggested that the Authority caused delays, which resulted in an EPC project schedule slippage of 283 days, and that acceleration by R&M reduced this slippage by 52 days. The R&M Claim

[56] *See* In the United States District Court, Western District of Louisiana, Lafayette Division. The Robins & Morton Group versus Louisiana Energy and Power Authority as a Political Subdivision, at Paragraph 12 (Case No: 6:17 – CV – 00379 -RFD – PJH).

sought additional payments for "general conditions" (overhead), startup acceleration, extended engineering, profit, productivity (inefficiency), outstanding change orders, and an early completion bonus. The magnitude of the R&M Claim was approximately $14.8 million.

LEPA selected Berkley Research Group, LLC as a construction claims services contractor in January 2016 to review the R&M Claim and assist LEPA with developing a rebuttal and counter claim to the R&M Claim. On March 10, 2017, R&M filed suit against the Authority before the United States District Court, Western District of Louisiana, Lafayette Division in the amount of $17.9 million. The Authority stated its intention to vigorously defend against the claim and to pursue its own damages against R&M for the contractual schedule liquidated damages of approximately $12 million. On May 3, 2018, the above case was dismissed with prejudice.

The bottom line of this now apparently settled litigation is that the project suffered significant delays and cost overruns in becoming operational and, as is discussed in more detail later, was not delivered in a manner capable of delivering according to the projected specifications. Some party has to bear the costs of these now-realized risks, and unless LEPA is planning on pursuing litigation against the Design Engineer and/or the equipment vendors, the Member Participants are the only party left to shoulder these losses. LEPA-1 participants will be the ones who will have paid debt service and other costs associated with a plant that was supposed to be efficiently operating for the period it was delayed. Further, LEPA-1 Participants are the ones who will now have suffer the loss of promised energy savings from their investment, based on specifications which are now not being met. And, LEPA-1 Participants will have to shoulder the burden of fixed costs, which will not be recovered due to continuing unavailability of the units and lower-than-projected dispatch.

UPC did not find anywhere in either ERG Consultant Engineering reports, or GDS Reports, where the risk of design, construction, and operations by an inexperienced party, with a bi-furcated contracting practice was specifically analyzed or addressed, especially in relation to the alternative of avoiding these risks by procuring contracted for power purchase agreements from already built generation with associated transmission costs.

Also, as mentioned above, either due to faulty design, faulty construction or faulty operations, Houma continues to experience a negative impact from LEPA-1, primarily because LEPA-1 is seeing extended periods of unavailability and deratings and is significantly more inefficient and underutilized than was originally projected. Originally, LEPA-1 was projected to have a utilization rate of around 74%, however, statistics for 2016 and 2017 indicate a utilization rate below 50%. In fact, according to reports generated by LEPA, due to outages, deratings and other issues for the period of January 2017 through March 2019 LEPA-1 was only available for full dispatch less than 57% of the days, and for the most recent first quarter of 2019, LEPA-1 was only available for full dispatch less than 37% of the days.

The heat rate of LEPA-1 was originally projected at 7.985 MMBtu/Mwh.[57] The 2016 actual heat rate was 8.734 MMBtu/Mwh.[58] The heat rate is the determining factor in a unit's fuel cost. That heat rate is 9.4% higher than the original projected specifications, and as a result, puts LEPA-1 at a significant cost disadvantage in the MISO day ahead and real time markets, which select units for generation based on economic order.[59] As a consequence, the LEPA-1 unit also has a significantly lower utilization rate, or capacity factor, than was originally projected. Original budgeting for LEPA-1 indicated a utilization rate of 74%.[60] The 2016 utilization rate was only 35.2%, and the 2017 production was 227,545 Mwh for a capacity utilization of42%.[61] The projected 2018 capacity utilization rate is projected to be 57.6%.[62]

The higher heat rate, and lower utilization rate, have significant cost implications for the annual LEPA-1 budget. Table 5 compares the 2018 LEPA-1 budget with a 58% capacity factor and heat rate of 8.73 MMBtu/Mwh, against a constructed budget based on the projected 7.97 MMBtu/Mwh heat rate and a 74.2% capacity factor.[63] As can be seen in the table below, LEPA-1 would be 52% more expensive on a $/Mwh basis to members than originally projected. If the unit does not improve, as

[57] *See* 2013 Consulting Engineer's Report, at B-32.
[58] *See* 2016 Consulting Engineer Report, at Table 4.1.
[59] (Two large Entergy CCGT's will enter into the MISO market in the next two years. These units have heat rates around 6.5 MMBTU/MWh, a 25% cost advantage in bidding into the day ahead market.).
[60] *See* 2013 Consulting Engineer's Report, at B-32 (The 2013 Consulting Engineer's Report did hedge the projected capacity utilization rate by stating, "Prior to LEPA's decision to join MISO, the Project was anticipated to operate at a capacity factor of 74% or greater. This was primarily due to two factors: (i) the Project was anticipated to be the most efficient unit under LEPA control, and (ii)) the Project would be located in a transmission constrained region in Southeast Louisiana. In MISO, LEPA intends to offer the Project into the MISO's Day-Ahead and Real-Time Operating and Reserve markets. As such, MISO will be responsible for dispatching the Project in coordination with all other MISO generating resources. While MISO's coordinated dispatch level of operation of the Project is unknown at this time given there is no historical MISO dispatch in the region to rely upon, the favorable characteristics of the Project do not change simply by joining MISO. Until such time as MISO implements transmission system improvements in the region, the unit is expected to remain an efficient unit in a transmission constrained region.).
[61] *See* LEPA 2017 Submitted Financial, at 9 (*stating* that MWH produced for 2017 was 227,545. At full utilization, the unit should produce 61.5 x 365 x 24 = 538,740 MWh.).
[62] Louisiana Energy and Power Authority, LEPA Unit 1, Proposed Budget (2018).
[63] (The table is backward engineered to approximate the 2018 budget. Some parameters in the table may be different than actual 2018 numbers.).

budgeted to 2018, from its 2017 performance, then LEPA-1 would be 116% more expensive on a \$/Mwh basis.

Table 5: LEPA-1 Operating Budget 2018 versus Original Projection

		2018 Budget	Original Parameters
Capacity Factor		0.58	0.76
MW	\$/Mwh	310,584	409,442
MISO Revenues	34.71	-\$10,780,978	-\$14,212,565
Heat Rate	MMBtu/Mwh	8.73	7.97
NG \$/MMBtu		\$3.05	\$3.05
Fuel Costs	\$/Mwh	\$8,259,980	\$9,936,614
Water & Treat.	0.60	\$187,012	\$246,538
LTSA \$/Mwh	2.59	\$804,412	\$1,060,456
		\$9,251,404	\$11,243,608
	\$/Mwh		
MISO and LEPA Credits	0.61	\$190,358	\$250,949
Net Energy Margin		-\$1,339,216	-\$2,718,008
Operating Costs		\$2,705,284	\$2,705,284
Administration		\$677,904	\$677,904
Debt service		\$7,787,366	\$7,787,366
Renewals		\$389,360	\$389,360
Contingency		\$240,000	\$240,000
Power Related Costs		\$11,799,914	\$11,799,914
Total Costs		\$10,460,698	\$9,081,906
Net Total Costs \$/Mwh		\$33.68	\$22.18
Percentage Cost Difference		52%	

VI. Timeline of LEPA-1

UPC has supplemented below the 2016 Consulting Engineer's Report timeline for LEPA-1[64] with milestones it could locate that that occurred before October 13, 2010. Our entries are noted in bold.

1. Houma's July 2010 Feasibility Study[65] recommended that Houma's optimal generation combination of new generation capacity was 25 MW of combined-cycle capacity and 15 MW of peaking capacity. However, LEPA was only committing to the development of a new combined-cycle generation facility, and, thus, Houma did not pursue an independent development course for a 15 MW peaking facility, but instead continued to rely on its existing steam-turbine generation to meet its peaking power requirements.[66]

2. In July 2010, LEPA distributed a draft resolution to members for participation in the LEPA-1 project ("Project"). Initial Project participation was open to all LEPA members, but members had to make collectively a financial commitment of $1,750,000 by October 2, 2010 to become project members with MW share entitlement depending on the proportional financial commitment. By the October deadline, six members had committed to the Project.

3. October 2, 2010, LEPA's members, including Houma, agreed to proceed with the development and construction of a 65 MW combined-cycle facility, which would be located near Morgan City, Louisiana.[67]

4. On October 13, 2010, the LEPA Board of Directors authorized initial funding in the amount of $1,750,000 for the development and preliminary engineering activities associated with the development by LEPA of a new 64 MW (nominal) combined cycle gas turbine generating resource to be located on land adjacent to Morgan City's existing generating facility.

5. In January 2011, LEPA issued a Request for Qualifications for Owner's Engineering Design Services in furtherance of LEPA's development of the new CCGT generating facility. In May of 2011, LEPA selected the engineering design firm of Burns & Roe Enterprises, Inc. ("BRE") as the most qualified firm to provide owner's engineering design services for LEPA-1.

6. In 2012, GDS provided its 2012 updated feasibility analysis of LEPA-1. GDS recommended that Houma proceed with 22 MW of LEPA-1 and a 15 MW CT internal unit. GDS indicated that the MISO market would provide an effective hedge to the risks of ownership of these two units.

7. LEPA entered into Power Sales Contracts, dated as of June 1, 2013, with each of the six participants in LEPA-1 for the purpose of financing the cost of acquiring and constructing the

[64] Louisiana Energy and Power Authority, LEPA Unit No. 1 Annual Report (2016).
[65] (Requested by UPC, not in current documents.).
[66] *See* 2012 Updated GDS report, at 12.
[67] *See* Resolution of the Board of Directors of the Louisiana Energy & Power Authority, Re: Ratification of Project Development Cost Agreements and Amounts of Participation for Development of New 64 Megawatt Combined Cycle Combustion Turbine Generating Resource (October 21, 2010).

LEPA-1 unit. The Power Sales Contracts between LEPA and the participants required that LEPA, to the extent LEPA-1 is operable, offer LEPA-1 in the MISO Energy and Operating Reserve Markets and to prepare the budgets required under Section 5 of the Power Sales Contracts.

8. On October 13, 2013, LEPA issued the Series 2013A bonds totaling $120,770,000 to fund construction and development of LEPA-1. During 2013, LEPA-1's major environmental permits were obtained, and LEPA contracted with suppliers for procurement of the major equipment for LEPA-1. Since 2013, LEPA has provided additional service which includes interfacing with MISO and operation and management of the LEPA 1 generation unit.

9. On June 1, 2013, as part of its future integration into MISO, LEPA began receiving reliability coordination services from MISO. MISO acts as the designated NERC Reliability Coordinator ("RC") for the interconnected bulk electric transmission systems throughout MISO's footprint. In its role as RC, MISO ensures the operating reliability of these systems on a planning basis and for real-time system operations.

10. In January 2014, LEPA selected Robins & Morton Group ("R&M") to provide Engineering, Procurement and Construction Services for LEPA-1. The construction contract dated January 14, 2014 between LEPA and R&M (the "EPC Contract") provided for a commercial operation date ("COD") for the commencement of LEPA-1's operation of September 22, 2015. The EPC Contract limits the schedule related liquidated damages to 20 percent of the contract value of $58,966,407, or approximately $11.8 million.

11. 2014 and 2015: Throughout the construction of LEPA-1, LEPA observed construction and commissioning delays it believes are attributable to R&M, and R&M has submitted to LEPA notices of purchaser caused delays related primarily to the major equipment purchased by LEPA.

12. Through its Owner's Engineer, LEPA notified R&M that LEPA-1 achieved commercial operation on April 14, 2016, however, production was sporadic. Continuous operation started Jun 1, 2016.

13. LEPA selected Berkley Research Group, LLC as a construction claims services contractor in January 2016 to review the R&M Claim and assist LEPA with developing a rebuttal and counter claim to the R&M Claim.

14. On March 10, 2017, R&M filed suit against LEPA before the United States District Court, Western District of Louisiana, Lafayette Division in the amount of $17.9 million, Case No:6:17 CV – 00379 – RFD – PJH

15. On May 3, 2018, the above case was dismissed with prejudice.

VII. Post hoc Review of Matters Associated With LEPA-1

A. Houma's Current Long Generation Position

As evidenced by Exhibit 1 of the 2013 Consulting Engineers Report, LEPA planned for Houma to be long in generation by 22.6 MW. Without LEPA-1's 22.0 MW, and using the same growth and resource projections, Houma would have maintained a 0.6 MW margin. This margin would, thus, be thin, but workable considering the MISO secondary markets for power.

Post hoc to Exhibit 1, and the decision to implement LEPA, the actual capacity surplus that manifested was impacted by other factors such as: (1) the actual load growth (as opposed to what was projected), and (2) a derate to the MW capacity of the Legacy Units by MISO in 2015.

For the load growth projection, the 2013 Consulting Engineer Report indicated the load growth projection used in developing Exhibit 1 was the result of a statistical analysis of weather and economic factors.[68] The load growth projection used for Houma was a 1.24% annual load growth. It is of note that Morgan City had a projection of a 0% load growth factor, with no provided rationale for the differences. The actual load growth rate for Houma turned out to be overstated, as the actual growth in load has not changed since 2013 (i.e. a 0% load growth rate).[69] This reduced Houma's demand for generation by approximately 4 MW.

The second post hoc factor was a de-rating of the Houma Legacy Units. The ICAP[70] rating of the three steam power Legacy Units of Houma were collective derated by MISO from 76 MW to 62 MW, a reduction of 14 MW.[71]

UPC modified Exhibit 1 for Houma using a 0% projected load growth rate and for the derated units. See Table 6 below. This table is indicative of the current long position of Houma, as has been

[68] *See* 2013 Consulting Engineer Report, Exhibit 1, at fn 1.

[69] *See* 2013 Consulting Engineer Report, at Exhibit 1 *and* Spreadsheet *2018-2019 Houma Resource Adequacy* (The 2013 Consulting Engineer Report Exhibit 1 indicates Houma's System Peak demand at 84.5 MW in 2013. According to the LEPA ECC Houma MISO coincident peak demand in 2017 was 79.2 MW. This is the MISO coincident peak, the ERG Consulting Engineer's used a 95% factor for conversion between the LEPA and MISO peaks, MP = .95 x LP, converting Houma's 2017 MISO system peak would be 83 MW, a slight decline from 2013.).

[70] ICAP, installed capacity rating of a generator, UCAP is the unforced capacity rating of the unit. UCAP is ICAP adjusted for forced outage rate.

[71] *See* spreadsheet *PY15-16 LEPA PRA final* (This occurred in 2015, Houma Unit #16 had the most significant reduction from 39 MW to 27 MW..

evidenced by the amount of zonal resource credits ("ZRC") that Houma has been granted pursuant the MISO PRA.

Table 6: Houma Load And Capability Balance modified by Post Hoc Changes 1/

	2010	2011	2012	2013	2014	2015 1/	2016	2017	2018	2019	2020
Peak Demand Responsibility											
System Peak Demand	85.7	84.4	85.9	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0
	2.6	2.5	2.6	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Plus Transmission Losses											
MISO Coincident Load (95%)	83.8	82.6	88.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5
Plus Planning Reserves	12.9	14.4	14.8	12.3	12.2	12.1	12.0	11.9	11.9	11.9	11.9
Total Capacity Requirement	96.7	97.0	103.3	98.8	98.7	98.6	98.5	98.4	98.4	98.4	98.4
Available Resources (UCAP)											
Rodemacher	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7
SWPA	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
HMA ST #14	11.6	11.6	11.6	11.6	11.6	10.7	10.7	10.7	10.7	10.7	10.7
HMA ST#15	24.8	24.8	24.8	24.8	24.8	24.4	24.4	24.4	24.4	24.4	24.4
HMA ST #16	39.4	39.4	39.4	39.4	39.4	27.0	27.0	27.0	27.0	27.0	27.0
The Project	-	-	-	-	-	-	26.6	26.6	26.6	26.6	26.6
CT Project						-	-	-	-	-	-
Total Resources Capacity	103.0	103.0	103.0	103.0	103.0	89.3	115.9	115.9	115.9	115.9	115.9
Capacity Surplus	6.3	6.0	(0.3)	4.2	4.3	(9.3)	17.4	17.5	17.5	17.5	17.5

1/ the Changes Resource rating are based on the PY 15-16 LEPA PRA Final spreadsheet

B. ZRC Credits

As mentioned earlier in this report, Houma is not its own Load Serving Entity ("LSE"). Rather, LEPA acts as the LSE for Houma. Practically, the way the MISO PRA works is that generation is awarded Zonal Resource Credits ("ZRCs"). If a particular generator is long generation, they will have excess ZRC credits. By contrast, if an LSE is short generation needed to serve its load, then LSE will need to procure ZRC credits in the PRA Market to fill that shortage. Houma is long generation, but LEPA is short. Because LEPA is the LSE, Houma is not getting a direct allocation of the ZRC credits that it could earn in its own name if it were the LSE. Houma has been materially long every year since LEPA-1 has provided capacity credit in the PRA, beginning with the 2017/2018 Planning Year (i.e. June 1,2017 thru May 31, 2018).

Because Houma is not its own LSE, it has relied on LEPA in order to receive any value for its excess capacity. The actual sale of capacity is not as seamless as the ability to sell ZRC credits in the PRA, and it requires locating a third-party buyer, who has the option to wait and just procure its needed capacity on a short term basis for what has been historically low PRA prices. In January of 2017, LEPA and Houma began discussing a methodology for Houma to realize value for its excess capacity. LEPA indicated that, because it was short, it was seeking capacity prior to the 2017/2018 PRA, and it had received firm pricing of $0.25kW-mth and $0.30kW-mth. These are prices to procure capacity, not ZRCs. Ultimately, in February of 2017, LEPA offered to buy Houma's excess capacity for the period of the 2017/2018 PRA Planning Year for $0.25 kW-mth, and Houma accepted this price. This actually resulted in a favorable price for Houma, relative to the price Houma would have received from the PRA for ZRC credits, which price was $0.05 kW-mth. For the 2017/2018 planning year, Houma, thus, received $0.20 excess on 20.2 MW of capacity, which equated to approximately an extra $4,000 per month.

For the period covered by the 2018-2019 PRA Planning Year, Houma and LEPA agreed to the same $0.25 kW price for Houma's excess 16.4 MW of capacity. The decrease in capacity from 20.2 MW to 16.4 MW is largely driven by the excessive forced outages of LEPA-1. Those forced outages reduce the capacity accreditation that LEPA-1 is able to receive. While Houma received a favorable result for the period covering the 2017/2018 Planning Year, the result for the period covering the 2018/2019 Planning Year was a modest loss, compared to the value of ZRCs in the PRA. The ZRC value for the 2018/2019 Planning Year was $0.30 per kW-mth on the 16.4 MW, which equated to a loss to Houma from the value of the ZRC credits of $820 per month.

UPC, recommends that Houma investigate becoming its own LSE where it is in sole control of the value of its own length in MISO. In this way, the ZRC credits belong to Houma, and not LEPA, and Houma is still free to hold discussions with LEPA, or any other party, concerning the sale of its excess capacity prior to the PRA, but has the security of the ZRC Credits for its own benefit.

C. LEPA-1 and the Retirement of Morgan City and Plaquemine Older Steam Units

As the result of the investment in LEPA-1, Morgan City and Plaquemine retired 89.1 MW of older steam units, further cementing the necessity of the LEPA-1 unit. Morgan City filed Attachment Y notifications with MISO in 2015 for Units 3 and 4, a subtotal of 58 MW. Plaquemine filed a separate Attachment Y for Units 1 and 2, a subtotal of 44 MW, for a total of 102 MW. LEPA-1 added 64 MW to the LEPA fleet capacity, the subtraction of the 102 MW of steam units resulted in a net decrease of resources to serve load in LEPA. The cities of Morgan City and Plaquemine retired the several legacy units as a cost cutting measure.

The retirements were initiated on the advice of LEPA, which has responsibility for their operation and allocation of operating costs. A resolution by the Morgan City Council outlines the justification for these retirements.[72]

> *WHEREAS, LEPA has advised the City that the continued operation and maintenance of the Morgan City Generating Plant has become economically inefficient in LEPA's production of electric energy when considering: (i) the age of the various generating units, (ii) the necessity for a significantly increased level of expenditures related to maintaining the units in operable condition, (iii) the lack of readily available replacement parts and systems and, (iv) the relatively high heat rates of the units when compared to much lower heat rates readily available by LEPA's participation in the Midcontinent Independent System Operator (MISO) wholesale electric markets; and*
>
> *WHEREAS, LEPA has advised the City that in order to maintain the Morgan City Generating Plant in 2015 it estimates that it will cost*

[72] *Resolution Approving the Return of Ownership and Operations of the Joseph Cefalu Generating Station to Morgan City by the Louisiana Energy & Power Authority and Authorizing the Disposition and Sale of the Plant Equipment*, Morgan City Council (June 2015).

$2,952,000 in operating, maintenance and reliability fixed cost expense excluding fuel and consumables; and

WHEREAS, LEPA can replace the annual fixed cost of maintaining and operating the Generating Plant in the MISO wholesale electricity markets for approximately $661,000, or less, and reduce the cost of FRS to the City by approximately 4-6 mills/kWh; and

WHEREAS, LEPA has advised the City that it will return the ownership and operation of the Morgan City Generating Plant to the City effective midnight on May 31, 2015 assuming MISO approval; and

WHEREAS, the City's participation in LEPA Unit No. 1 assures continued availability of an efficient generating facility located within the City; and

WHEREAS, the Council is desirous of continually exploring means for a reduction in its wholesale cost of electricity and the passing on of such savings to its retail electric consumers; and

WHEREAS, given the economic obsolescence of the Morgan City Generating Plant the Council elects not to incur an estimated $2,952,000 of annual expense to continue to operate and/or maintain the Morgan City Generating Plant;

NOW THEREFORE, BE IT RESOLVED BY THE COUNCIL OF THE CITY OF MORGAN CITY THAT: The Council hereby directs the Mayor to sell or dispose of the Morgan City Generating Plant in the manner provided for by law upon return of the plant to the City by LEPA.

Plaquemine, as noted, followed suit in retiring its two additional legacy units.[73] The retirements by Morgan City and Plaquemines of their legacy generating units created two economic issues for Houma. First, it resulted in LEPA leveraging Houma's length in generation. LEPA, for its customers was buying generation at the low prices of the PRA, relying on the length provided by Houma and others to drive those prices down. Houma, for its part, was only getting paid those low PRA prices for the length it did not need, while also paying the high costs associated with LEPA-Unit 1, and while receiving less efficient generation savings than it was projected to receive. Second, the retirements by Morgan City and Plaquemines of their legacy generating units, taxes the Houma Legacy Units, by reducing the generation in the load pocket. Now, the Legacy Units are needed more than ever to supply reliable generation to ease the constraints of the southern Louisiana load

[73] *See* Plaquemine Filing of MISO Attachment Y.

pocket. All the while, Plaquemines and Morgan City escape the cost of having to maintain their generators in a ready to serve state.

ROBERT LANE SISUNG

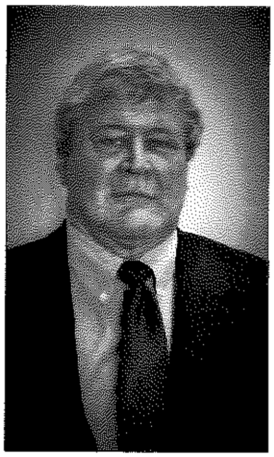
Mr. Sisung earned a Bachelor of Science degree in Accounting from Louisiana State University. After graduation, he sat for and passed the Certified Public Accountant exam and subsequently attended Loyola University Law School where he earned a Juris Doctorate. After law school, Mr. Sisung earned an LL.M. in Tax Law from the University of Florida. Mr. Sisung is a fully licensed General Securities Representative, a licensed insurance agent in the state of Louisiana, and a member of the Louisiana State Bar.

Mr. Sisung has over two decades of experience in financial, real estate and investment transactions. His most recent projects include successful development and implementation of the Healthcare Finance Consulting and Financial Litigation Services/Regulatory Consulitng business lines for the Sisung Group, where he specializes in providing consulting to regulators of utilities. The Sisung Group's work in these endeavors has produced hundreds of millions of dollars for the firms' clients and the state.

The Financial Litigation Services/Regulatory Consulting business line has primarily supported governmental entities in cases before tribunals. Mr. Sisung manages an array of regulatory and financial experts in coordinating a cohesive approach to providing expert witness services for complicated financial and regulatory matters. Mr. Sisung himself also provides expert testimony and assist in the creation of settlements and orders of judgment. His personal involvement in the representation of the LPSC has helped to provided critical and effective safeguarding of LPSC-jurisdictional rate payers.

Mr. Sisung's previous endeavors include the successful creation, development and implementation of the corporate finance and mergers and acquisitions operations of Sisung Securities Corporation; the creation and operations of Sisung Capital that include raising and investing millions of dollars in venture capital funds in Louisiana; the creation and operation of the Sisung Film Finance Division; and the growth and management of over $1 billion dollars in assets under management in Sisung Investment Management Services. Mr. Sisung also manages and directs all Sisung Group real estate, project management, and business development projects including multi-facility capital infrastructure projects. Mr. Sisung sits on the investment committee for Sisung Investment Management Services, LLC and also serves as in-house counsel for the five companies that comprise the Sisung Group.

Mr. Sisung serves as the primary point of contact for clients, and is will be responsible for coordinating and managing all of our firm's resources, including the direct provision of consulting and litigation services.



J. THOMAS MCGUCKIN, PH.D.

Dr. McGuckin holds a Bachelor of Arts in Economics from Pomona College, a Masters of Economics from Colorado State University, and a Ph.D. in Economics from the University of Wisconsin. Dr. McGuckin is a member of both the American Economics Association and the National Association of Regulatory Utility Commissioners.

Dr. McGuckin is retired from New Mexico State University where he was a Professor of Economics for thirty-three years. He has also been an associate for the Center for Public Utilities at New Mexico State University, whose program offerings are officially sectioned by the National Association of Regulatory Utility Commissioners.

Dr. McGuckin is an economics expert in the fields of utilities in electricity, water, wastewater, natural gas and solid waste. In this role, he has provided detailed technical and policy analyses and recommendations to numerous state and federal regulatory bodies. He has focused his consulting efforts on performing cost of service analysis, rate analysis and rate design, regulatory policy development, utility governance, and planning and cost allocation processes for investor-owned electric utility companies. His experience has allowed him to build an in-depth knowledgebase on a wide array of topics including: the appropriate accounting standards and practices for electric utilities, resource planning and resource adequacy, cost recovery mechanisms for utilities, regional transmission planning organizations and ancillary services markets, day ahead energy and operating reserves markets and real time energy and operating reserves markets, transmission hedges, annual revenue rights and financial transmission rights, fuel cost recovery, qualified facilities, avoided cost, certification of transmission, certification of generation or power supply purchases, competitive procurement of supply side resources, market forecasting and futures, and federal regulations impacting or potentially impacting utilities' operations and/or policy.

Dr. McGuckin now pulls from his background and experience in serving the Sisung Group as its chief expert regulatory consultant.

Dr. McGuckin serves the Sisung Group's clients by providing economics-related consulting services.

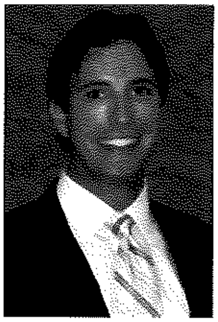
ROBERT VOSBERG

Mr. Vosberg holds a Bachelor of Science in Engineering from University of Wisconsin, Platteville.

Mr. Vosberg has nearly forty years practicing in the regulated utility space, including over ten years at Alliant Energy as an Energy Delivery Project Manager. He also has experience with the Wisconsin Electrical Cooperative Association, where he was responsible for direct interaction with State and Federal Regulatory bodies including providing testimony. In this role, Mr. Vosberg also served on committees that provided recommendations to such regulatory bodies for proposed agency rules and regulations. In his role with Scenic Rivers Energy Cooperative, Mr. Vosberg served as the Director of Engineering, where he was responsible for system planning, system protection, equipment procurement, rate schedules, and standards.

Mr. Vosberg has litigation experience related to economic development efforts and other special projects. He has served on local, State and National committees providing technical guidance to various regulatory agencies, regional bodies, economic groups and other associations. Mr. Vosberg has also performed rate equalization studies and other special projects.

Today, Mr. Vosberg provides technical support to various clients relating to new transmission and generation facilities. He has direct responsibility for interactions with multiple Transmission Providers (PJM, MISO including MISO South, ERCOT,SPP, WECC, etc.) for Interconnection and Transmission Service requirements. Mr. Vosberg has extensive knowledge of SERC member utilities including Southern Company, Progress Energy, TVA, Florida Utilities, Electric Municipals and Electric Cooperatives. He provides guidance to clients regarding Transmission Market requirements, including current and future pricing structures, FERC regulatory requirements and State regulatory requirements.



PAUL THOMAS CHASTANT, III

Mr. Chastant holds a Bachelor of Science in Accounting and a Minor in History from Louisiana State University. He also holds a Juris Doctor from Tulane University Law School. Mr. Chastant is a member of the Louisiana State Bar, a Certified Public Accountant licensed to practice in Louisiana, and a Certified Mergers and Acquisitions Advisor.

Mr. Chastant has accounting and financial advisory consulting experience in areas that include external audit, acquisition due diligence, revenue and expenditure growth projection, litigation support, and business valuation, gained while working as a Financial Consulting and External Audit Staff Accountant with Postlethwaite & Netterville, one of the largest accounting firms in the state of Louisiana. In this position, he assisted publicly traded companies' internal audit departments in assessing European foreign corporate subsidiaries' compliance with Sarbanes-Oxley Act reporting requirements. His financial consulting experience ranges from constructing detailed financial accounting and reporting policies and procedures manuals for clients to consulting on issues of cross-border financial consolidations, US GAAP financial reporting, and SEC reporting and compliance for US-based multi-national, public companies.

While at Tulane, Mr. Chastant's study of the law was concentrated on issues surrounding transaction law, including corporate law, mergers and acquisitions, practical aspects of hostile acquisitions, and corporate taxation. Prior to graduating Tulane, he completed an externship with The Louisiana Supreme Court Clerk of Court, where he was tasked with assisting in an ongoing revision to the Louisiana Supreme Court's Practice and Procedure Rules and assigned a project to begin drafting e-filing rules for the Louisiana Supreme Court.

Today, Mr. Chastant uses his accounting background and his legal expertise in his role as Vice President of Project Development for the Sisung Group. While at Sisung, Mr. Chastant has assisted in the successful development of the Financial Litigation Services Division and has used his qualifications and experience to help create a streamlined approach for financial experts to be able to support attorneys in the provision of litigation support for complex utility financial transactions. Mr. Chastant has assisted in every aspect from discovery to testimony to drafting of settlement agreements and orders for judgment.

Mr. Chastant and Mr. Sisung are responsible for coordinating and managing all of our firm's resources for its regulatory consulting clients.