B6: Leblanc Bulk Station One-line

[redacted]

B7: Scanlan Station One-line

[redacted]

B8: Semere Road Station One-line

[redacted]

B9: Vatican Station One-line

[redacted]

Benefit Analysis

Southwest Louisiana Electric Membership Corporation (SLEMCO)

GridLiance

A NEXTERA ENERGY TRANSMISSION COMPANY

February 2025

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Executive Summary

Southwest Louisiana Electric Membership Corporation (SLEMCO) is a member owned electric cooperative which serves its customers located in Acadia, Saint Martin, Lafayette, Saint Landry, and Vermilion Parishes. There are certain transmission assets that are currently owned by Pelican South Central LLC (Pelican), formerly Cleco-Cajun, that SLEMCO will acquire ownership of on April 1, 2025. As explained in the Application, SLEMCO intends to sell certain of those assets to GridLiance Louisiana (GLL) (Transmission Assets).

A benefit analysis has been conducted and is described in this report to quantify the benefits associated with SLEMCO's sale of the assets to GLL. Benefits have been calculated over a 10-year time frame in order to be consistent with the rate impact analysis performed. The benefits quantified are broken into three main categories:

1. Reduced Integration and Compliance Costs
2. Reduced Loss of Load Savings
3. Joint Planning Savings

The expected benefit to Louisiana ratepayers over ten years is estimated to be $103.7M, with a breakdown of the benefits for each category shown in Figure 1.

Figure 1: Breakdown of $103.7M 10 Year Total Benefit

Introduction

SLEMCO intends to sell the Transmission Assets listed in Table 1 to GLL and GLL intends to integrate these assets into the Midcontinent Independent System Operator (MISO).

Table 1. SLEMCO Transmission Assets

Station	Highest kV	Lowest kV	Year Constructed	Age (Years)
Crowley	138 kV	25 kV	1992	32
East Opelousas	138 kV	25 kV	2003	21
Hebert	138 kV	25 kV	1979	45
Judice	138 kV	138 kV	1982	42
Krotz Springs	138 kV	13.8 kV	1982	42
LeBlanc Bulk	138 kV	138 kV	1968	56
Scanlan	138 kV	25 kV	1987	37
Semere Road	138 kV	138 kV	1984	40
Vatican	138 kV	25 kV	1976	48

The quantification of benefits involve the following three main categories:

1. Reduced Integration and Compliance Costs;
2. Reduced Loss of Load Savings; and
3. Joint Planning Savings.

Each of the categories of benefits are developed in the following sections.

Reduced Integration & Compliance Costs

The Transmission assets listed in Table 1 are classified as part of the Bulk Electric System (BES) and are subject to compliance with over seventy North American Electric Reliability Corporation (NERC) Reliability Standards. Further, a NERC registered Balancing Authority (BA), Reliability Coordinator (RC), Planning Coordinator (PC), Transmission Owner (TO), Transmission Operator (TOP), Transmission Planner (TP), and Transmission Service Provider (TSP) needs to be responsible for the Transmission Assets. Currently, Pelican meets compliance with these standards through Cleco Corporate Holdings LLC (Cleco) acting as the BA, TO, TOP, and TP and with MISO acting as the BA, PC, RC, and TSP. However, once SLEMCO acquires these assets on April 1, 2025, compliance with the NERC Reliability Standards will be transferred to SLEMCO. SLEMCO has three options to address NERC compliance:

1. SLEMCO handles obligations internally;
2. SLEMCO hires a third party; or
3. SLEMCO sells the assets to GLL.

The costs for each of these options are detailed below. This analysis assumes SLEMCO would integrate the assets into MISO.

Regardless of the option chosen, certain initial capital investments are required and are therefore omitted from this analysis. For example, initial capital investments include installation of communication equipment at each of the transmission assets.

Option 1 - SLEMCO maintains the Transmission Assets and Staffs Internally

For SLEMCO to handle the NERC compliance obligations internally, it will need to become a registered BA, TO, TOP, and TP in addition to being a Distribution Provider (DP). For this option, SLEMCO would be wholly responsible for all NERC compliance and be held liable for any violation. A violation of a NERC Reliability Standard can result in a monetary penalty up to $1,291,894[1] per day per violation depending on the risk and severity of the violation.

SLEMCO would need to hire a minimum of 12 additional full-time employees (FTE) which is broken down in to the following five categories:

- Six (6) NERC Certified Operators
- Two (2) FTEs for EMS/SCADA support
- Two (2) FTEs for NERC, SERC, FERC compliance activities
- One (1) FTE for Transmission Planning
- One (1) Regulatory Attorney

The six NERC certified operators and two EMS/SCADA support staff are necessary to staff a 24x7 control center and meet the NERC BA and TOP Reliability Standards. The transmission planning engineer will be dedicated to supporting their TP and TO obligations. The two FTEs dedicated to NERC compliance are necessary to develop and maintain documentation for demonstrating compliance for SERC and NERC audits. Finally, the additional regulatory attorney will be required to support the additional obligations associated with the transmission assets being subject to MISO's OATT.

Based the U.S. Bureau of Labor Statistics June 2024 release of Employer Costs for Employee compensation, the average total compensation of Utilities Industry is $78.33/hour[2] based on a 40-hour workweek and 52 weeks in a year translates to a $162,926.4 on average. For simplicity and to be conservative, the annual cost for each FTE is assumed to be $160,000 per year, for a total cost of $1,920,000 annually.

In order to maintain the operators NERC certification, the operators will need to complete a minimum of 160 continuing education hours (CEH) every 3 years as defined by NERC[3]. SLEMCO could choose to develop their own internal training program; however, this would require additional staff. Alternatively, SLEMCO could use training provided by a third-party which is expected to cost approximately $200 per CEH. Leveraging a third-party for training will result in SLEMCO having a recurring cost to maintain their operators certification of $192,000 every three years (160 CEH * $200/CEH * 6 Operators) or $64,000 annually.

In addition to the new staff, becoming a BA and TOP requires an initial capital investment to develop a primary and backup control center. The primary and backup control centers need to be designed to ensure uninterrupted 24-hour-a-day monitoring and control of the transmission assets and to comply with NERC's CIP and COM standards. SLEMCO already has a dispatch center in their main office in Lafayette; however, this dispatch center is not required to currently, and therefore would not have all the necessary processes and equipment, to comply with the applicable CIP/COM standards. Therefore, even if SLEMCO were to use its existing dispatch center, it would need to be upgraded. The necessary upgrades include development of a SCADA system, additional communications equipment, a small data center, and upgraded physical security. The high-level estimated cost to upgrade their existing dispatch center to a NERC certified control center is estimated to be $5,000,000.

The backup control center can be developed at a location that SLEMCO already owns such as one of the existing substations, for example Vatican. This will eliminate the need to purchase or lease additional

[1] Section 3.2.1 Page 7; https://www.nerc.com/AboutNERC/RulesOfProcedure/Appendix_4B_effective%2020210119.pdf

[2] Table 4 on page 9; https://www.bls.gov/news.release/pdf/ecec.pdf

[3] Table 2.1 on page 6; https://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/SOC_Program_Manual_V4.1.pdf

real estate. The high-level cost to construct a backup control center at an existing SLEMCO site is estimated to be $10,000,000.

SLEMCO will have additional one-time costs to develop the initial procedures and controls, costs for onboarding the additional staff, and contracting other parties to provide support for an audit; these costs are not being estimated. A summary of all the costs and their frequency is provided in Table 2.

Table 2: Summary of costs for SLEMCO for compliance & integration internally

Description	Cost ($)	Frequency
Construct Primary Control Center	5,000,000	One-time
Construct Backup Control Center	10,000,000	One-time
12 Additional Full-time Staff	1,920,000	Annual
Annual Training for Operators	64,000	Annual

Option 2 – SLEMCO maintains the Transmission Assets and hires a Third-Party

SLEMCO also has the option to hire third party entities/consultants to help them meet all the NERC compliance obligations and integrate the assets into MISO. SLEMCO would need to hire an entity to provide BA, TOP, TP, NERC, SERC, FERC regulatory and compliance support services. Even though these entities would perform the necessary work, SLEMCO would still to be wholly responsible for compliance and liable for any violations, similar to Option 1, as they would continue to own the assets.

To GridLiance's knowledge, there is no single third-party consultant that offers all the necessary services to cover the above identified five categories. The estimated annual costs to provide the necessary services is detailed in Table 3.

Table 3: Estimated costs for hiring a Third-Party for compliance & integration

Function	Cost ($)	Frequency
BA & TOP Services	600,000	Annual
TP Services	500,000	Annual
Regulatory	500,000	Annual
Compliance	1,000,000	Annual

Option 3 – SLEMCO sells the Transmission Assets to GridLiance

SLEMCO has the option to transfer the Transmission Assets to GLL to own and operate them. Since GLL would own the assets, GLL would then be responsible for NERC, SERC, FERC compliance, rather than SLEMCO staffing or hiring a third part for compliance. GridLiance Holdco, LLC (GridLiance) is already a registered TO and TP and its affiliate Lone Star Transmission, LLC (LST) is a registered BA and TOP which currently performs those services for GridLiance Heartland's (GLH) assets in Illinois and Kentucky. Additionally, affiliates of GLL already perform the needed processes and tasks needed to comply with the NERC Reliability Standards, and GLL can implement its NERC, SERC, FERC compliance using these resources and already well developed plans and processes. The estimated costs for GLL to perform all the necessary compliance and integration functions are shown in Table 4.

Table 4: GLL costs for compliance & integration

Function	Cost ($)	Frequency
BA & TOP Services	400,000	Annual
TP Services	150,000	Annual
Regulatory	150,000	Annual
Compliance	150,000	Annual

Comparison of Options

Using the developed costs for each of the options a 10-year projection of costs was developed. All annual costs were assumed to increase with inflation and the 2023 annual inflation rate of 3.4% as reported by the U.S. Bureau of Labor Statistics Consumer Price Index[4] data was assumed. The year costs for each option are provided in Appendix B – Compliance and Integration Options Yearly Cost and are summarized in Table 5.

Table 5: Comparison of Costs over 10 Years

	10 Year Cost ($)	Savings from GLL Ownership ($)
Option 1 – SLEMCO Handles Internally	$38,168,000	$28,242,000
Option 2 – SLEMCO Hires Third-Party	$30,361,000	$20,435,000
Option 3 – GLL Ownership	$9,926,000	-

Based on the developed costs GLL ownership would save the Louisiana ratepayer between $28.2M to $20.4M over the course of 10 years. Changes to inflation would impact the precise dollar amount but do not change the overall conclusion that GLL ownership will significantly reduce costs compared to SLEMCO retaining ownership.

Reduced Loss of Load Savings

The second category of benefits examined the historical performance of the Transmission Assets and the expected performance of the Transmission Assets under GLL's operation and maintenance practices to project the amount of loss of load events due to disruptions on the transmission system. The process to quantify the amount of reduced loss of load and associated value of this reduction is shown in Figure 2.

Figure 2: Overview of the Process to Quantify Loss of Load Savings

Historical Data

Six years of historical station outage data was obtained from SLEMCO for the Transmission Assets. The historical data included the station where the outage occurred, start time of the outage, the reason for the outage, the amount of load being served as measured just prior to the outage, and the duration of the outage. Based on the outage reason an additional flag was added to distinguish outages caused by major storm events (e.g. hurricanes) and based on the one-line diagrams of the stations an additional flag was added to indicate if the station had breakers on the transmission lines. Additionally, a megawatt hour (MWh) Impact of the outage was calculated by multiplying the load amount and duration of the outage. For outages with a long duration, multiple hours, this MWh Impact is a conservative estimate as it does not take into consideration the expected change in load that would normally occur throughout the day and is most impactful for the estimated MWh Impact for major storm events. The detailed historical outage data is in Appendix C – Historical Outage Data and annual averages are provided in Table 6.

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[4] https://www.bls.gov/charts/consumer-price-index/consumer-price-index-by-category-line-chart.htm

Table 6: Summary of Historical Outage Data

	Non-Major Storm		Major Storm	
	Non-Breakered	Breakered	Non-Breakered	Breakered
Total # of Stations	5	4	5	4
Total # of Outages	21	5	2	2
Total Duration of Outages (hr)	3.7	2.6	245.4	77.5
Total MWh Impact of Outages (MWh)	22.7	38.0	4,579.5	922.6
Average Outages per Station	4.2	1.25	0.4	0.5
Average Outages per Year	3.5	0.8	0.3	0.3
Average Duration of Outage (hr)	0.2	0.5	122.68	38.7
Average MWh Impact of Outage (MWh)	1.1	7.6	2,289.7	461.3

The totals are simple summations and counts of the outages separated out by the Major Storm and Breakered flags. The averages were calculated as follows:

- Average Outages per Station = Total # Outages / Total # of Stations
- Average Outages per Year = Total # of Outages / 6
- Average Duration of Outage = Total Duration of Outages / Total # of Outages
- Average MWh Impact of Outage = Total MWh Impact / Total # of Outages

By comparing the historical outage data between the breakered and non-breakered stations the following trend is observed:

1. A breakered station has a 70% reduction in the total number of non-major storm outages

$$\frac{(Average\ Outages\ per\ Station_{Breakered} - Average\ Outages\ per\ Station_{Non-Breakered})}{Average\ Outages\ per\ Station_{Non-Breakered}}$$

$$= \frac{(1.25 - 4.2)}{4.2} = -70\%$$

Future Projection of Loss of Load

Using the historical data, the number of outages and total MWh Impact of those outages can be calculated as follows:

- 10 Year Total # Outages = Average Outage per Year * 10
- 10 Year Total MWh Impact = 10 Year Total # Outages * Average MWh Impact of Outage

This method assumes the Transmission Assets continue to perform as they have for the past 6 years. Importantly, the method does not account for the degradation of the equipment in the stations which would cause an increase in outages due to equipment failure. Additionally, this method does not account for future load growth on the SLEMCO system meaning the MWh Impact is lower than what would be expected in the future. As a result, this method produces a conservative estimate of the future loss of load caused by outages of the Transmission Assets. The calculated 10 Year projected amount of load loss is provided in Table 7.

Table 7: 10 Year Projected Loss of Load

	Non-Major Storm		Major Storm	
	Non-Breakered	Breakered	Non-Breakered	Breakered
10 Year Total # of Outages	35	8	3	3

10 Year Total MWh Impact	37.9	60.8	6,869.2	1,383.9

Impact of GLL Ownership

No transmission owner can eliminate outages on the system; however, under GLL ownership three significant changes will occur that will increase the reliability and performance of the Transmission Assets and reduce the future projected amount of loss of load. The three changes are:

1. Capital Investment to the Transmission Assets;
2. Improved Maintenance Practices; and
3. Application of well-developed and tested major storm response processes.

The capital investment will focus on upgrading the non-breakered stations and replacing aging equipment. A summary of the planned capital investment is provided in Table 8 with additional details on the cost estimate for each of the stations provided in Appendix D – Construction Work Plan. The current configuration of the non-breakered station will result in a complete outage of the station for a fault on either transmission lines feeding the station. However, by implementing this capital investment plan the operational flexibility of the Transmission Assets will be significantly improved by allowing the stations to automatically be fed from either transmission source. Based on the historical data the impact of upgrading the station to be breakered will result in a 70% reduction in the amount of loss of load for non-major storm.

For major storm events, the impact of upgrading a station is expected to result in a 10% reduction in the amount of loss of load. The addition of breakers will not completely avoid an outage as a result of a major storm but is expected to reduce the overall duration of a major storm outage by allowing for the station to be fed from either of transmission lines feeding the station. For example, for Crowley, if there is an outage of its primary feed from Richard it can be fed from Scott. Further, if both lines are lost this would allow for Crowley to come back online sooner by not requiring both lines to be restored prior to re-energizing Crowley.

Table 8: Summary of Future Upgrades

Station	Description of Upgrade	Estimated Cost
Hebert	Upgrade Station - Add two breaker positions	$5.2M
Crowley	Upgrade Station - Add two breaker positions	$5.1M
Scanlan	Upgrade Station - Add two breaker positions	$5.1M
Vatican	Upgrade Station - Add two breaker positions	$5.1M
Semere Road	Upgrade Station - Add two breaker positions	$5.1M
LeBlanc Bulk	Replace Breaker	$2.8M
Judice	Replace Breaker	$2.8M
	Total Cost	**$31.2M**

Additionally, GLL will implement the inspection and maintenance practices implemented by affiliate companies. These practices strive to be more proactive by taking preventative steps to address issues identified through regular inspections of the equipment rather than waiting for equipment failure. For example, Florida Power & Light Company industry leading major storm response and restoration processes will also be leveraged in the event of any future major storm which will shorten the duration of any resulting outages. These two changes will result in an expected reduction in the amount of loss of load for non-major storm and major storm events of 10% and 5% respectively.

Implementing all three of these changes will result in a 36.4 MWh (37%) reduction for non-major storm events and a 1,099.6 MWh (13%) reduction for major storm events over the course of 10 years. Overall, the impact of GLL ownership is expected to result in a total of 1,136.0 MWh reduction in loss of load over 10 years as detailed in Table 9.

Table 9: 10 Year MWh Impact of GLL Ownership to Expected Loss of Load

	Non-Major Storm		Major Storm	
	Non-Breakered	**Breakered**	**Non-Breakered**	**Breakered**
Impact of Breaker Additions	26.5	-	686.9	-
Impact of Improved Maintenance	3.8	6.1	-	-
Impact of Improved Storm Response	-	-	343.5	69.2
Total	**30.3**	**6.1**	**1030.4**	**69.2**
Grand Total	**1,136.0**			

Value of reducing loss of load

The MISO tariff defines the Value of Lost Load (VOLL) as the value that represents the price consumers are willing to pay to avoid an interruption of electrical service. The current effective VOLL as defined by MISO is $3,500 per MWh; however, effective September 30, 2025 the system VOLL will increase to $35,000 per MWh. For the calculation of the loss of load savings a VOLL of $35,000 per MWh is assumed since this is the expected VOLL as defined by the MISO tariff that will be effective once the assets are transferred to GLL and fully integrated into MISO. The calculation of the value of reduced loss of load is simply defined as:

- Value of Reduced Loss of Load ($) = Reduced Loss of Load (MWh) * Value of Lost Load ($/MWh)

Using the expected amount of reduced loss of load the expected value of this reduction is $39.8M over 10 years as detailed in Table 10.

Table 10: 10 Year Value of Reduced Loss of Load from GLL Ownership

	Non-Major Storm		Major Storm	
	Non-Breakered	**Breakered**	**Non-Breakered**	**Breakered**
Impact of Breaker Additions	$0.93M	-	$24.05M	-
Impact of Improved Maintenance	$0.13M	$0.21M	-	-
Impact of Improved Storm Response	-	-	$12.02M	$2.42M
Total	**$1.06M**	**$0.21M**	**$36.07M**	**$2.42M**
Grand Total	**$39.77M**			

Joint Planning Savings

The third category of benefits examined the historical transmission expansion in the area and estimated future impact of integrating the Transmission Assets into MISO to develop a more comprehensive transmission expansion plan through joint planning activities between all the Transmission Owners which meets future reliability needs considering all available transmission assets in the region. Currently, the Transmission Assets are not under MISO's functional control, nor are they owned by a MISO Transmission Owner. Instead, they exist outside of the MISO processes and are excluded from consideration when developing future transmission solutions for the system. Effectively, MISO must work around these assets to resolve any identified reliability constraints even if leveraging them would result in a more cost-effective solution.

MISO has a transmission expansion plan called the MISO Transmission Expansion Plan (MTEP). The MTEP is an 18-month process which takes input from MISO stakeholders and culminates in transmission projects being approved by MISO's Board of Directors. A MISO transmission owner must submit all their future transmission plans to MISO for review and approval. The ultimate goal of the MTEP is to develop a set of the most cost-effective projects to address reliability, policy, and economic needs identified by stakeholders. During the 2023 MTEP 572 projects were approved totaling nearly $9B and specifically for Louisiana there were 39 projects totaling $2.5B.

In order to estimate the benefit of joint planning in the area, first, a historical example of how SLEMCO's transmission assets could have been leveraged to produce a more cost-effective solution is explored. Then the historical example is projected into the future to provide an estimate for joint planning savings.

Historical Example

During the 2017 and 2018 MTEP planning cycles, Entergy proposed two projects to address expected reliability issues called the North Atchafalaya Load Project (ALP) and East Atchafalaya Load Project (ALP) with an estimated cost of $65.0M and $97.7M respectively. Although the projects were approved in two separate MTEP planning cycles they were envisioned as a single solution to resolve thermal and voltage issues observed for several multiple element contingencies (N-1 and N-1-1 or NERC TPL-001 category P2 and P6). Without the projects an estimated 300 to 380 MW of load would be shed to resolve the various P6 events. Additional detail on the MTEP projects is provided in Appendix E – Historical MTEP Appendix D1 Project Descriptions.

Shortly before the East ALP project was approved in the MTEP18 cycle, Entergy approached MISO to discuss the expected cost increase for the two projects and the possibility of replacing the projects with a different solution which could resolve the reliability issues for less than the revised estimated $198.9M cost of the original projects. As a result, MISO initiated a targeted study to examine the possible transmission solutions to resolve the thermal and voltage constraints and eliminate the need to shed load in the area for the various P6 events. During this targeted study MISO met with three of the Louisiana Transmission Owners, Entergy, Cleco, and Lafayette Utilities System, to collaboratively develop transmission solutions. SLEMCO was not included in those discussions as they were not a MISO Transmission Owner and MISO was unaware of their system.

The targeted study resulted in the Sellers – LeBlanc Project (SLP) for an estimated cost of $84M and at the time resulted in $115M savings compared to the original North and East ALP. SLP was an innovative project as it involved expanding Cleco's Sellers Road station and connecting it to Entergy's Conrad station (which is physically adjacent to SLEMCO's Le Blanc station) to provide an additional high-voltage path to the south of Lafayette. SLP was approved in the MTEP19 cycle replacing the North and East ALP and was split into two projects to be constructed by Entergy and Cleco. Ultimately, the Sellers – LeBlanc Project would go into service in 2022 with an actual cost of $82M. An overall timeline of the project approvals and completion is provided in Figure 3.

Figure 3: Timeline of Project Approval and Completion

A $115M savings to Louisiana ratepayers exemplifies the value of joint planning as well as the important role MISO plays in achieving those savings; however, the reality is an even more cost-effective solution could have been developed if SLEMCO was included in the process. The underlying reliability issue was the inability of the transmission system being able to deliver power from north of Lafayette to the south and specifically to delivering power to SLEMCO's LeBlanc 138 kV station. During MISO's targeted study the existing SLEMCO 138 kV lines were not known to MISO because the models used by MISO showed that there was a large load being served at Le Blanc but none of SLEMCO's 138 kV lines were modeled.

Had MISO been aware of SLEMCO's larger 138 kV system they could have considered additional alternatives to SLP. The simplest and least expensive option could have been operator-initiated system adjustments after the initial transmission outage. The load being served from Le Blanc can also be served from the Judice and Vatican station by closing in normally open points in SLEMCO's 138 kV system. Alternatively, a more robust long-term solution which avoids using system adjustments and accommodate future load growth could have been permanently closing in SLEMCO's 138 kV normally open points to create a 138 kV loop. In order to operate SLEMCO's currently radially operated 138 kV as a networked loop would require upgrading three 138 kV lines (Judice – Mouton, Mouton – Neuville, and Vatican – Gajan) for an estimated cost of $16.8M. As a result of more comprehensive joint planning the system with all the Louisiana transmission owners would have resulted in $65.2M to $82M in additional savings compared to the plan MISO ultimately adopted.

Total Joint Planning Savings

$65.2M of Additional Savings Could Have Been Achieved

The primary issue with pursuing either of these options at the time was the assets associated with these options are not under MISO's functional control nor owned by a MISO Transmission Owner and as such can only be used as mitigation through a formal agreement between all the effected parties (i.e. MISO, Entergy, and SLEMCO) as well as MISO being aware that the assets existed.

Future Projection

Based on the historical example a projected joint planning savings can be estimated by assuming a similar situation will occur in the future. The Lafayette area continues to see load growth and continues to be constrained by the transmission system's ability to transfer power from the 500 kV in the north to the 230/138 kV system in the south. N-1-1 events associated with the north-south 230/138 kV lines which connect to 500 kV system will eventually require additional transmission to the Lafayette area. Although the exact upgrade will be dependent on the underlying reliability issue, including all the existing transmission assets in the area will result in the most cost-effective solution. Conservatively, a similar situation is likely to occur at least once in the next 15 years.

Assuming a similar situation will occur once in the next 15 years, an estimated 10-year benefit can be calculated on a pro-rata basis, resulting in an estimated 10-year joint planning savings of $43.5M ($65.2M * [10 years / 15 years]).

Conclusion

A benefit analysis has been conducted to quantify the benefits associated with SLEMCO's sale of the assets to GLL. Benefits have been calculated over a 10-year time frame to be consistent with the rate impact analysis performed. The benefits quantified are broken into three main categories:

1. Reduced Integration and Compliance Costs;
2. Reduced Loss of Load Savings; and
3. Joint Planning Savings.

The expected benefit to Louisiana ratepayers over ten years is estimated to be $103.7M, with a breakdown of the benefits for each category shown in Table 11.

Table 11: Summary of Calculated Benefits

Benefit	Estimate ($M)
Reduced Integration and Compliance Costs	$20.4M
Reduced Loss of Load Savings	$39.8M
Joint Planning Savings	$43.5M
Total	**$103.7M**

Appendix A – List of Applicable NERC Standards

Standard	BA	PC	RC	TO	TOP	TP	TSP
BAL-001	X	-	-	-	-	-	-
BAL-002	X	-	-	-	-	-	-
BAL-003	X	-	-	-	-	-	-
BAL-004	X	-	-	-	-	-	-
BAL-005	X	-	-	-	-	-	-
BAL-502	-	X	-	-	-	-	-
CIP-002	X	-	X	X	X	-	-
CIP-003	X	-	X	X	X	-	-
CIP-004	X	-	X	X	X	-	-
CIP-005	X	-	X	X	X	-	-
CIP-006	X	-	X	X	X	-	-
CIP-007	X	-	X	X	X	-	-
CIP-008	X	-	X	X	X	-	-
CIP-009	X	-	X	X	X	-	-
CIP-010	X	-	X	X	X	-	-
CIP-011	X	-	X	X	X	-	-
CIP-012	X	-	X	X	X	-	-
CIP-013	X	-	X	X	X	-	-
CIP-014	-	-	-	X	X	-	-
COM-001	X	-	X	-	X	-	-
COM-002	X	-	X	-	X	-	-
EOP-004	X	-	X	X	X	-	-
EOP-005	-	-	-	X	X	-	-
EOP-006	-	-	X	-	-	-	-
EOP-008	X	-	X	-	X	-	-
EOP-010	-	-	X	-	X	-	-
EOP-011	X	-	X	X	X	-	-
FAC-001	-	-	-	X	-	-	-
FAC-002	-	X	-	X	-	X	-
FAC-003	-	-	-	X	-	-	-
FAC-008	-	-	-	X	-	-	-
FAC-011	-	-	X	-	-	-	-
FAC-014	-	X	X	-	X	X	-
FAC-501	-	-	-	X	-	-	-
INT-006	X	-	-	-	-	-	X
INT-009	X	-	-	-	-	-	-
IRO-001	X	-	X	-	X	-	-
IRO-002	-	-	X	-	-	-	-
IRO-006	X	-	X	-	-	-	-

Standard	BA	PC	RC	TO	TOP	TP	TSP
IRO-008	-	-	X	-	-	-	-
IRO-009	-	-	X	-	-	-	-
IRO-010	X	-	X	X	X	-	-
IRO-014	-	-	X	-	-	-	-
IRO-017	X	X	X	-	X	X	-
IRO-018	-	-	X	-	-	-	-
MOD-025	-	-	-	X	-	-	-
MOD-026	-	-	-	-	-	X	-
MOD-027	-	-	-	-	-	X	-
MOD-031	X	X	-	-	-	X	-
MOD-032	X	X	-	X	-	X	X
MOD-033	-	X	X	-	X	-	-
NUC-001	X	X	X	X	X	X	X
PER-003	X	-	X	-	X	-	-
PER-005	X	-	X	X	X	-	-
PRC-002	-	-	X	X	-	-	-
PRC-004	-	-	-	X	-	-	-
PRC-005	-	-	-	X	-	-	-
PRC-006	-	X	-	X	-	-	-
PRC-008	-	-	-	X	-	-	-
PRC-010	-	X	-	X	-	X	-
PRC-011	-	-	-	X	-	-	-
PRC-012	-	X	X	X	-	-	-
PRC-017	-	-	-	X	-	-	-
PRC-019	-	-	-	X	-	-	-
PRC-023	-	X	-	X	-	-	-
PRC-024	-	X	-	X	-	-	-
PRC-025	-	-	-	X	-	-	-
PRC-026	-	X	-	X	-	-	-
PRC-027	-	-	-	-	-	X	-
TOP-001	X	-	-	-	X	-	-
TOP-002	X	-	-	-	X	-	-
TOP-003	X	-	-	X	X	-	-
TOP-010	X	-	-	-	X	-	-
TPL-001	-	X	-	-	-	X	-
TPL-007	-	X	-	X	-	X	-
VAR-001	-	-	-	-	X	-	-

Appendix B – Compliance and Integration Options Yearly Cost

		Cost ($1,000) 3.4% escalation for recuring costs										
Option	**Description**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**Total**
1	Control Centers	$15,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$15,000**
	Staff	$1,920	$1,985	$2,053	$2,123	$2,195	$2,269	$2,347	$2,426	$2,509	$2,594	**$22,420**
	Continuing Education	$64	$66	$68	$71	$73	$76	$78	$81	$84	$86	**$747**
	Total	**$16,984**	**$2,051**	**$2,121**	**$2,193**	**$2,268**	**$2,345**	**$2,425**	**$2,507**	**$2,592**	**$2,681**	**$38,168**
2	BA & TOP Services	$600	$620	$641	$663	$686	$709	$733	$758	$784	$811	**$7,006**
	TP Services	$500	$517	$535	$553	$572	$591	$611	$632	$653	$676	**$5,839**
	Regulatory	$500	$517	$535	$553	$572	$591	$611	$632	$653	$676	**$5,839**
	Compliance	$1,000	$1,034	$1,069	$1,106	$1,143	$1,182	$1,222	$1,264	$1,307	$1,351	**$11,677**
	Total	**$2,600**	**$2,688**	**$2,780**	**$2,874**	**$2,972**	**$3,073**	**$3,178**	**$3,286**	**$3,397**	**$3,513**	**$30,361**
3	BA & TOP Services	$400	$414	$428	$442	$457	$473	$489	$505	$523	$540	**$4,671**
	TP Services	$150	$155	$160	$166	$171	$177	$183	$190	$196	$203	**$1,752**
	Regulatory	$150	$155	$160	$166	$171	$177	$183	$190	$196	$203	**$1,752**
	Compliance	$150	$155	$160	$166	$171	$177	$183	$190	$196	$203	**$1,752**
	Total	**$850**	**$879**	**$909**	**$940**	**$972**	**$1,005**	**$1,039**	**$1,074**	**$1,111**	**$1,148**	**$9,926**

Appendix C – Historical Outage Data

Station	Start	Reason Category	Major Storm Event	Breakered Station	Load (MW)	Duration (hr)	MWh Impact
East Opelousas	2/13/2018 0:50	Animal	FALSE	TRUE	3.5	1.13	4.0
Crowley Bulk	6/13/2018 17:32	Vegetation	FALSE	FALSE	8	0.08	0.7
Hebert	8/21/2018 10:03	Primary Failure	FALSE	FALSE	5.07	0.07	0.3
East Opelousas	9/11/2018 6:59	Animal	FALSE	TRUE	4	0.32	1.3
Vatican	12/28/2018 14:49	Hardware Failure	FALSE	FALSE	30	0.02	0.5
Scanlan	4/7/2019 17:07	Severe Storm / Lightning	FALSE	FALSE	14	0.03	0.5
Leblanc Bulk	4/13/2019 14:37	Hardware Failure	FALSE	TRUE	35	0.90	31.5
Hebert	12/2/2019 1:21	Unknown	FALSE	FALSE	4.3	0.25	1.1
Crowley Bulk	4/23/2020 1:56	Severe Storm / Lightning	FALSE	FALSE	7.4	0.08	0.6
Crowley Bulk	7/17/2020 6:56	Animal	FALSE	FALSE	5.7	0.45	2.6
Crowley Bulk	7/22/2020 7:58	Animal	FALSE	FALSE	5.9	0.45	2.7
Leblanc Bulk	8/27/2020 1:26	Severe Storm / Lightning	TRUE	TRUE	48	0.23	11.2
Hebert	8/27/2020 1:28	Severe Storm / Lightning	TRUE	FALSE	1.9	36.50	69.4
Crowley Bulk	8/27/2020 2:18	Severe Storm / Lightning	TRUE	FALSE	2.1	9.60	20.2
Crowley Bulk	9/17/2020 14:34	Hardware Failure	FALSE	FALSE	5	0.32	1.6
Hebert	10/9/2020 18:22	Severe Storm / Lightning	TRUE	FALSE	12	5.63	67.6
Scanlan	10/9/2020 19:07	Severe Storm / Lightning	TRUE	FALSE	14	71.13	995.9
Vatican	10/9/2020 19:30	Severe Storm / Lightning	TRUE	FALSE	28	70.05	1961.4
Crowley Bulk	10/9/2020 19:44	Severe Storm / Lightning	TRUE	FALSE	28	52.27	1463.5
Semere Road	10/9/2020 20:01	Severe Storm / Lightning	TRUE	FALSE	8.9	0.18	1.6
Krotz Springs	10/9/2020 20:04	Severe Storm / Lightning	TRUE	TRUE	11.8	77.23	911.4
East Opelousas	10/13/2020 8:43	Improper Coordination	FALSE	TRUE	3.2	0.13	0.4
Krotz Springs	10/13/2020 8:43	Improper Coordination	FALSE	TRUE	6.22	0.13	0.8
Scanlan	4/24/2021 0:38	Severe Storm / Lightning	FALSE	FALSE	17.7	0.05	0.9
Hebert	12/6/2021 15:23	Severe Storm / Lightning	FALSE	FALSE	4	1.22	4.9
Crowley Bulk	1/6/2022 9:33	Human Error	FALSE	FALSE	5.6	0.05	0.3
Crowley Bulk	7/2/2022 19:44	Overloaded / Failed Equipment	FALSE	FALSE	7	0.08	0.6
Hebert	9/2/2022 16:14	IOU Breaker Tripped	FALSE	FALSE	5.8	0.03	0.2
Scanlan	11/27/2022 18:32	Primary Failure	FALSE	FALSE	13	0.05	0.7
Crowley Bulk	12/23/2022 3:20	Unknown	FALSE	FALSE	14	0.05	0.7
Hebert	1/24/2023 17:49	Severe Storm / Lightning	FALSE	FALSE	4.9	0.13	0.7
Scanlan	2/1/2023 11:11	Overloaded / Failed Equipment	FALSE	FALSE	26.9	0.08	2.2
Crowley Bulk	11/7/2023 14:56	Overloaded / Failed Equipment	FALSE	FALSE	9.1	0.10	0.9
Hebert	11/29/2023 15:56	Hardware Failure	FALSE	FALSE	3.8	0.00	0.0

Appendix D – Construction Work Plan

Based on the age of the Transmission Assets, an initial inspection of their condition, and the current configuration of the system, GLL plans to make several upgrades to the Transmission Assets with a total cost of approximately $31.2M. The upgrades are focused on the Transmission Assets that are 30 years or more as the equipment within those stations is approaching the end of their useful life and will be prone to a significantly higher risk of failure.

Hebert	
Upgrade Station with 2 Breaker Positions	$2.7M
2nd set of PTs	$.2M
Control Enclosure	$.8M
Rock for yard	$.1M
Contingency	$1.1
AFUDC	$.4M
Project Implementation Cost	**$5.2M**

Crowley	
Upgrade Station with 2 Breaker Positions	$2.7M
2nd set of PTs	$.2M
Control Enclosure	$.8M
138 kV GOAB Switch	$.1M
Contingency	$1.1M
AFUDC	$.4M
Project Implementation Cost	**$5.1M**

Scanlan	
Upgrade Station with 2 Breaker Positions	$2.7M
2nd set of PTs	$.2M
Control Enclosure	$.8M
138 kV GOAB Switch	$.1M
Contingency	$1.1M
AFUDC	$.4M
Project Implementation Cost	**$5.1M**

Vatican	
Upgrade Station with 2 Breaker Positions	$2.7M
2nd set of PTs	$.2M
Control Enclosure	$.8M
138 kV GOAB Switch	$.1M
Contingency	$1.1M
AFUDC	$.4M

Project Implementation Cost	**$5.1M**

Semere Road	
Upgrade Station with 2 Breaker Positions	$2.7M
2nd set of PTs	$.2M
Control Enclosure	$.8M
138 kV GOAB Switch	$.1M
Contingency	$1.1M
AFUDC	$.4M
Project Implementation Cost	**$5.1M**

LaBlanc Bulk	
Replace existing GCB	$1.5M
2nd set of PTs	$.2M
Relay Upgrade	$.3M
138 kV GOAB Switch	$.1M
Contingency	$.6M
AFUDC	$.2M
Project Implementation Cost	**$2.8M**

Judice	
Replace existing GCB	$1.5M
2nd set of PTs	$.2M
Relay Upgrade	$.3M
138 kV GOAB Switch	$.1M
Contingency	$.6M
AFUDC	$.2M
Project Implementation Cost	**$2.8M**

Appendix E – Historical MTEP Appendix D1 Project Descriptions

MTEP Project 12112 – North ALP Project

MTEP17 APPENDIX D1

Project 12112: North ALP Project

Transmission Owner: **ENTERGY LOUISIANA, LLC.**

Project Description

Project 12112 is located in Lafayette Parish Louisiana. The area contains 230, 138 and 69kV networks, as well as 100 MW of generation resources at the Labbe generation plant.

This project will create two new 230/138kV taps in the area. The first new tap point is a new substation called Cankton, which will be constructed at the intersection of the Wells to Labbe 230kV line and the Colton to Bloomfield 138kV line. Both lines will be cut into the new substation. The second tap requires a new 230kV line to be built from Cankton to the existing 138kV Cecelia substation. 230/138kV transformers will be installed at both the Cankton and Cecelia substations. Figure P12112 illustrates the contingency, resultant violations and project to mitigate the reliability concerns. The estimated cost to implement project 12112 is $65 million, with an expected in-service date of December 1, 2021.

Project Need

Following a bus tie breaker fault at the Scott substation, multiple 138kV lines extending from Scott are removed from service. This contingency results in a thermal overload of the Scott to Cecelia circuit and voltage below the local planning criteria threshold at the Cecelia substation. These violations were observed in the 2027 summer scenario and illustrated in figure P12112.

Additionally, the loss of Delcambe to Moril and Meaux to Sellers Road – NERC TPL Category P6 Contingency – results in thermal overloads of Judice to Scott and Judice to Meaux 138kV circuit up 132%, observed in the 2019 summer scenario. This contingency results in over 300 MW of nonconsequential load loss. Project 12112 is part one of a two phase project to mitigate the load at risk following this contingency.

Figure P12112: A bus tie breaker fault at the Scott substation results in thermal overload of the Bonin to Cecelia 138kV line and voltage below criteria threshold at the Cecelia substation

Alternatives Considered

Alternatively, a rebuild option was considered. This alternative would have rebuilt the Scott substation, the Cecelia to Bonin 138kV line, the Scott to Semere 138kV line, the Champagne to Sunset 69kV line and the Richard to Colonial Academy 138kV line.

The rebuild option was rejected based on a higher cost to implement, numerous outages required to implement and project 12112 provides additional operational flexibility compared to this alternative.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

MTEP Project 12101 – East ALP Project

Project 12101: East ALP Project

Transmission Owner: Entergy Louisiana LLC.

Project Description

The East ALP project will construct a new 230 kV line from the existing Cecelia substation to a new 230 kV substation called Lake Peigneur, approximately 26 miles long, in the Lafayette area of Louisiana. A new 230/138 kV transformer will be installed at the Lake Peigneur substation. The expected in-service date of the project is June 1, 2022. The estimated cost of the project is approximately $100 million.

Project Need

In the Lafayette area of Louisiana approximately 380 MW of load is served by the Judice, Meaux, Abbeville, Leblanc and Delcambre substations. These substations are served by well networked hubs, the Moril and Scott substations, as well as a 230/138 kV transformer at the Meaux substation. Loss of two of three of these sources caused loading up to 156 percent of the capacity of the single remaining source. Up to 140 MW of load shed is required to mitigate the excessive flows in the 2023 Summer scenario.

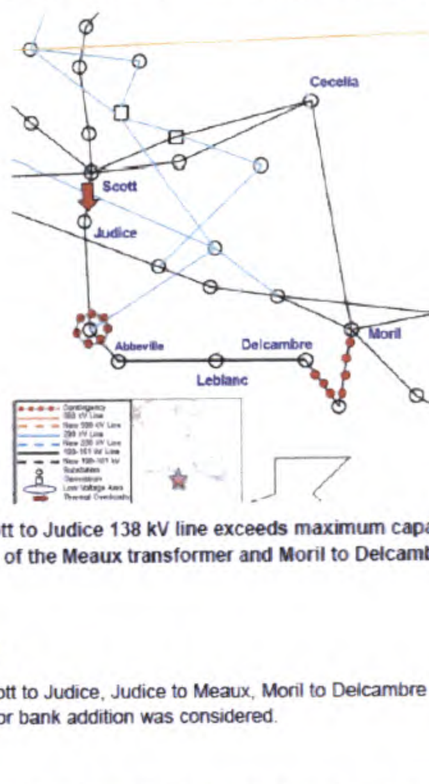

Figure P12101: The Scott to Judice 138 kV line exceeds maximum capacity by 56 percent for the loss of the Meaux transformer and Moril to Delcambre line

Alternatives Considered

Reconductoring of the Scott to Judice, Judice to Meaux, Moril to Delcambre and Delcambre to Leblanc lines, as well as a capacitor bank addition was considered.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

MTEP Project 17045 – Sellers Road Expansion

Project 17045 - Sellers Road Expansion

Project Description

The Sellers Road Expansion, along with MTEP 17044, is replacing MTEP17/18 projects 12101 East ALP and 12112 North ALP. The projects changed through significant collaboration between CLECO, Entergy, Lafayette Utilities System, and MISO to develop a lower cost solution. The proposed $84 million alternative is a joint solution between CLECO and Entergy - Louisiana and will save customers $115 million compared to the original ALP projects.

CLECO's portion of the project is to Expand Sellers Road Substation to add a 4 terminal 138 kV substation tapped into and out of the Habetz to Flanders 138 kV line near Sellers Road substation. A 500 MVA 230/138 kV Auto connecting the existing 230 kV sub to the New 138 kV Sub will be added. The project's estimated cost is $14.1 million and the estimated in service date is December 1, 2021.

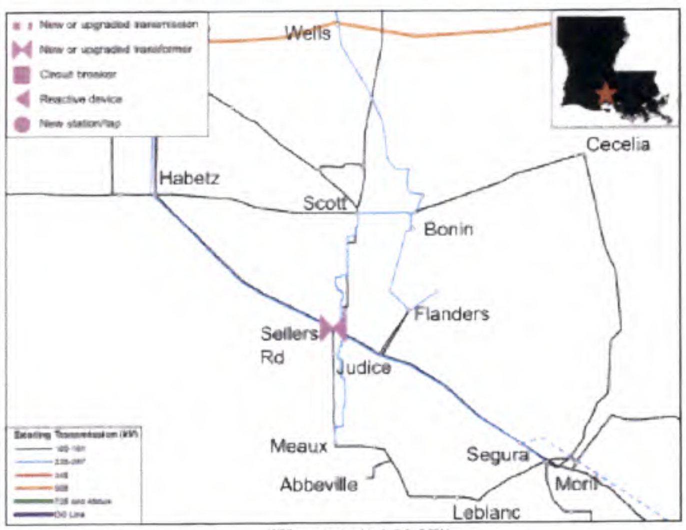

Figure 4.4-#17045-1: Geographic transmission map of project area

Project Need

In the Lafayette area of Louisiana approximately 380 MW of load is served by the Judice, Meaux, Abbeville, Leblanc, and Delcambre substations. These substations are served by well networked hubs, the Moril and Scott substations, as well as a 230/138 kV transformer at the Meaux substation. Loss of two of three of these sources caused loading up to 137 percent of the capacity of the single remaining source. Up to 150 MW of load shed is required to mitigate the excessive flows. Table 4.4-#17045-1 shows the thermal loading of various limiting elements during different events with and without this project in service.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P2.2	Cecelia - Bonin 138 kV	145	101	84
P2.4	Cecelia - Bonin 138 kV	145	111	91
P6	Scott - Judice 138 kV	241	137	83

P6	Delcambre - Moril 138 kV	251	125	60
P6	Meaux - Abberville 138 kV	233	111	64
P6	Cecelia - Bonin 138 kV	145	111	78

Table 4.4-#17045-1: Thermal loading drivers

Alternatives Considered

This project, along with MTEP 17044, is replacing MTEP17/18 projects 12101 East ALP and 12112 North ALP to save customers $115 million.

4.4.4 Cooperative Energy

Based on TO submission and MISO independent assessment Cooperative Energy will have six projects for inclusion in Appendix A at an estimated cost of $63 million. $19 million of which represents EML's estimated cost required to interconnect these new facilities to EML's existing transmission system. All of the projects are other type projects.

Other Projects

Other projects do not meet the criteria to be considered as Baseline Reliability Projects (BRP), New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. Other projects may include projects to satisfy Transmission Owner and/or state and local planning criteria other than NERC or regional reliability standards, interconnect new Loads, relocate transmission facilities, address aging transmission infrastructure, replace problematic transmission plant, improve operational performance or address other operational issues, address service reliability issues with end-use consumers, improve aesthetics including but not limited to undergrounding overhead transmission facilities, address localized economic issues, and address other miscellaneous localized needs. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Project 15849 – Evans Loop Project

Project Description

Tap the existing Schlater to Evans 115 kV line with a 115 kV GOAB and build a new 115 kV line to Half Mile Switching Station. Add a new 115 kV line bay to Entergy's Schlater substation. The project's total estimated cost is $9.76 million, with Cooperative Energy paying $3.12 million and Entergy Mississippi LLC paying $6.64 million. The estimated in service date is April 1, 2021.

Project Need

The current radial transmission system results in 115 MW-miles and violates section 6.7 of Cooperative Energy's local planning criteria, which states that 100 MW-miles cannot be exceeded for any Point of Common Coupling. This project will provide a loop from the new Half Mile delivery point to Evans and remove the MW-mile violation.

MTEP Project 17044 – Sellers LeBlanc Project (SLP)

Project 17044 - Sellers Leblanc Project (SLP)

Project Description

The Sellers Leblanc Project, along with MTEP 17045, is replacing MTEP17/18 projects 12101 East ALP and 12112 North ALP. The projects changed through significant collaboration between CLECO, Entergy, Lafayette Utilities System, and MISO to develop a lower cost solution. The proposed $84M alternative is a joint solution between CLECO and Entergy - Louisiana and will save customers $115M compared to the original ALP projects.

The Sellers Leblanc Project will construct a new Sellers Road to Conrad 230 kV line (operate at 138 kV); which is approximately 19.2 miles based on preliminary routing. Add a 138 kV line breaker, switches, bus, etc. at the Conrad Substation. Add a 138 kV series reactor at the Cecelia 138 kV Substation on the line to Bonin. Reroute the existing Gecko to Cecelia 69 kV line (to facilitate the 230 kV line construction). The project's estimated cost is $69.9 million and the estimated in service date is December 1, 2021.

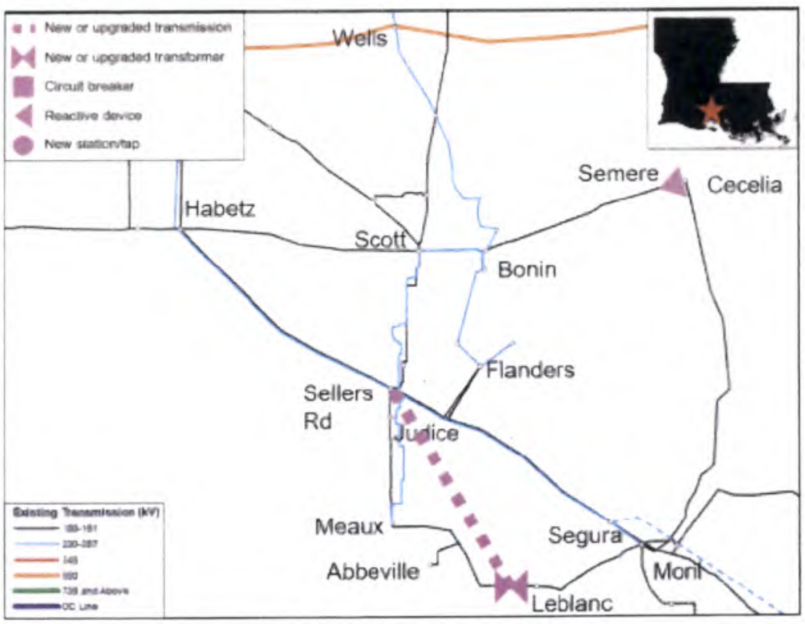

Figure 4.4-#17044-1: Geographic transmission map of project area

Project Need

In the Lafayette area of Louisiana approximately 380 MW of load is served by the Judice, Meaux, Abbeville, Leblanc and Delcambre substations. These substations are served by well-networked hubs, the Moril and Scott substations, as well as a 230/138 kV transformer at the Meaux substation. Loss of two of three of these sources caused loading up to 137 percent of the capacity of the single remaining source. Up to 150 MW of load shed is required to mitigate the excessive flows. Table 4.4-#17044-1 shows the thermal loading of various limiting elements during different events with and without this project in service.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P2.2	Cecelia - Bonin 138 kV	145	101	84
P2.4	Cecelia - Bonin 138 kV	145	111	91
P6	Scott - Judice 138 kV	241	137	83
P6	Delcambre - Moril 138 kV	251	125	60
P6	Meaux - Abbervillе 138 kV	233	111	64
P6	Cecelia - Bonin 138 kV	145	111	78

Table 4.4-#17044-1: Thermal loading drivers

Alternatives Considered

This project, along with MTEP 17045, is replacing MTEP17/18 projects 12101 East ALP and 12112 North ALP to save customers $115M.

Other Projects

Other projects do not meet the criteria to be considered as Baseline Reliability Projects (BRP), New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. Other projects may include projects to satisfy Transmission Owner and/or state and local planning criteria other than NERC or regional reliability standards, interconnect new Loads, relocate transmission facilities, address aging transmission infrastructure, replace problematic transmission plants, improve operational performance or address other operational issues, address service reliability issues with end-use consumers, improve aesthetics including but not limited to undergrounding overhead transmission facilities, address localized economic issues, and address other miscellaneous localized needs. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Project 17606 - Ponchatoula 230 kV: Add Breakers and Transfer Bus

Project Description

This project was submitted late due to Entergy's Operating Company realizing the work could be completed and considered a transmission upgrade for this cycle to enhance local reliability. Entergy is proposing to add line breakers and a transfer bus at the existing Ponchatoula 230 kV substation in South Louisiana. Ponchatoula 230 kV station currently does not contain transmission breakers or a transfer bus. The estimated in service date is December 1, 2021 and the estimated cost is $5.2 million.

Project Need

This project will reduce exposure to the large amount of customers served from the Ponchatoula 230 kV station to a line fault. This project also addresses operational concerns and provides flexibility during planned and unplanned outages.

Project 17608 - Michigan 230 kV Substation: Cut in Nelson to Manena 230 kV

Project Description

This project was submitted late due to Entergy's Operating Company realizing the work could be completed and considered a transmission upgrade for this cycle to enhance local reliability. Entergy is proposing to cut the new Nelson to Manena 230 kV line, project ID# 10008, in and out of the Michigan 230 kV station. The estimated in service date is December 1, 2020 and the estimated cost is $10.6 million.