OFFICIAL EXHIBITS

FILED
June 18, 2020
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IURC
PETITIONER'S
EXHIBIT NO. 2
9-11-20 AT
DATE REPORTER

PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY PURSUANT TO IND. CODE § 8-1-39-9 FOR: (1) APPROVAL OF AN ADJUSTMENT TO ITS ELECTRIC SERVICE RATES THROUGH ITS TRANSMISSION, DISTRIBUTION, AND STORAGE SYSTEM IMPROVEMENT CHARGE ("TDSIC") RATE SCHEDULE, STANDARD CONTRACT RIDER NO. 3; AND (2) AUTHORITY TO DEFER 20% OF THE APPROVED CAPITAL EXPENDITURES AND TDSIC COSTS FOR RECOVERY IN PETITIONER'S NEXT GENERAL RATE CASE.	)	**CAUSE NO. 45264 TDSIC 1**

PETITIONER'S SUBMISSION OF DIRECT TESTIMONY OF
<u>CHAD A. ROGERS</u>

Indianapolis Power & Light Company ("IPL" or "Petitioner"), by counsel, hereby submits the direct testimony and attachments of Chad A. Rogers.

Respectfully submitted,

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INDIANAPOLIS POWER & LIGHT COMPANY

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing was served this 18th day of June, 2020, by email transmission, hand delivery or United States Mail, first class, postage prepaid to:

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ATTORNEYS FOR APPLICANT
INDIANAPOLIS POWER & LIGHT COMPANY

VERIFIED DIRECT TESTIMONY

OF

CHAD A. ROGERS

ON BEHALF OF

INDIANAPOLIS POWER & LIGHT COMPANY

SPONSORING IPL ATTACHMENTS CAR-1 – CAR-6

VERIFIED DIRECT TESTIMONY OF CHAD A. ROGERS ON BEHALF OF INDIANAPOLIS POWER & LIGHT COMPANY

Q1. Please state your name, employer and business address.

A1. My name is Chad A. Rogers. I am employed by Indianapolis Power & Light Company ("IPL" or "Company"), whose business address is One Monument Circle, Indianapolis, Indiana 46204.

Q2. What is your position with IPL?

A2. I am Senior Program Manager in Regulatory Affairs.

Q3. Please describe your duties as Senior Program Manager.

A3. I provide financial, technical and regulatory analysis and manage various regulatory projects and filings.

Q4. Please summarize your educational and professional qualifications.

A4. I hold a Bachelor of Science Degree in Accounting and Finance from the Kelley School of Business at Indiana University. I also hold a Master of Business Administration Degree from the Lacy School of Business at Butler University. I received my Certified Public Accountant ("CPA") license for the State of Indiana and have fulfilled the necessary educational requirements to allow use of the CPA designation. I have also attended various regulated utility training courses such as Edison Electric Institute ("EEI") Utilities Accounting Courses (Intro and Advanced), EEI Electric Rates Advanced Course, and PWC Rate Case Experience Course. I also am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA").

Q5. What is your previous work experience?

A5. I have been an employee of IPL since April 5, 2006, initially as a Senior Accountant and later as a Section Leader in the accounting and external reporting team. From June 2009 to September 2013, I worked as a Senior Analyst and later as a Section Leader in Financial Planning and Analysis. I have been in Regulatory Affairs since September 2013 where I was a Senior Analyst until becoming a Senior Program Manager in 2018.

From February 2004 to April 2006, I was employed by Cinergy Corporation (now Duke Energy). At Cinergy, I held a Senior Accountant role and was responsible for various accounting, financial analysis, and financial reporting duties.

From January 2001 to January 2004, I was employed by KPMG LLP as a Senior Associate in assurance services. In that position, I was responsible for audits, reviews, compilations, and control assessments for clients spread over a wide range of industries.

Q6. Have you previously testified before this Commission?

A6. Yes. I provided testimony in IPL's Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Plan Filing in IURC Cause No. 45264. I have also provided testimony in IPL's Environmental Compliance Cost Recovery Adjustment proceedings, beginning in IURC Cause No. 42170-ECR-28. I also provided testimony in IPL's Electric rate case, IURC Cause No. 45029 ("IPL's most recent rate case").

Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of my testimony is to:

1. Provide an overall summary of IPL's requested relief.

2. Discuss how IPL's TDSIC 1 filing in this proceeding comports with the TDSIC Statute and certain accounting treatment approvals in the Order approving IPL's TDSIC Plan.

3. Discuss IPL's proposed netting of depreciation expense.

4. Explain why the WACC reflected in the Company's proposed revenue requirement is reasonable and the Commission should make no adjustment to the Company's pretax return.

5. Estimate the effect of IPL's TDSIC Plan on retail rates and charges over the plan term.

Q8. Are you sponsoring any attachments?

A8. Yes. I sponsor IPL Attachment CAR - 1 thru 4 which contain and support the estimate of the effect of IPL's TDSIC Plan on retail rates charges over the Plan term. I also sponsor IPL Attachment CAR - 5 which contains IPL Witness AMM Attachment 3 from IPL's most recent rate case. This attachment summarized the regulatory adjustment mechanisms available to the proxy group of electric utilities used in that case to estimate the cost of equity. I also sponsor IPL Attachment CAR - 6 which is the Petition in this proceeding.

Q9. Were these attachments prepared or assembled by you or under your direction and supervision?

A9. Yes.

Q10. Are you submitting workpapers?

A10. Yes. I am submitting workpapers in their native format that are the same as or support the attachments included with my testimony. These workpapers are the electronic spreadsheets and were prepared or assembled by me or under my direction and supervision.

1. <u>REQUESTED RELIEF</u>

Q11. What relief is IPL requesting?

A11. IPL is requesting approval of an adjustment to its electric service rates through a TDSIC in accordance with I.C. § 8-1-39-9. This relief effectuates the timely recovery of 80% of approved capital expenditures and TDSIC Costs, as defined in I.C. § 8-1-39-7, in connection with IPL's approved TDSIC Plan and deferral of the remaining 20% to be recovered as part of IPL's next general rate case. IPL's TDSIC Plan was approved in IURC Cause No. 45264. IPL also requests approval to adjust Petitioner's authorized return for purposes of I.C. § 8-1-2-42(d)(3) to reflect the incremental earnings that will result from this TDSIC Rider filing upon Commission approval in accordance with I.C. §8-1-39-13(b).

As ordered by the Commission, IPL will file semi-annual TDSIC riders, staggered by six months: one to establish the TDSIC rider factors and one to update the TDSIC Plan. In this TDSIC Rate Update filing, the following Witnesses present testimony to support the requested TDSIC factors:

Chad A. Rogers – Regulatory Policy	– Provide an overall summary of IPL's requested relief. – Discuss how IPL's TDSIC 1 filing in this proceeding comports with the TDSIC Statute and certain accounting treatment approvals in the Order approving IPL's TDSIC Plan. – Discuss IPL's proposed netting of depreciation expense. – Explain why the WACC reflected in the Company's proposed revenue requirement

	is reasonable and the Commission should make no adjustment to the Company's pretax return. – Estimate the effect of IPL's TDSIC Plan on retail rates and charges over the Plan term.
James (Jim) William Shields Jr. – Project Management	– Provide an overview of IPL's approved TDSIC Plan. – Provide progress of Projects. – Present TDSIC capital investments as of March 31, 2020. – Describe the capital investments. – Identify cost variances and justify the variance for specific projects that have an actual cost greater than the previously approved estimate.
Natalie Herr Coklow – Regulatory Accounting	– Present and support the TDSIC revenue requirement calculations. – Support timely recovery of 80% of the calculated TDSIC revenue requirement, and deferral of 20% of the calculated TDSIC revenue requirement for future recovery in IPL's next general rate case. – Explain how Plan development costs and depreciation and property tax expenses are treated in the calculation of the revenue requirement. – Discuss the evaluation of the change in the TDSIC revenue requirement compared to the two percent (2%) of total annual revenues in a 12-month period cap, as required by the TDSIC Statute. – Discuss the impact of the TDSIC factors proposed in this filing. – Present the tariff pages for the TDSIC Rider.

2. TDSIC STATUTE & TDSIC PLAN ORDER

Q12. Does this filing comport with the TDSIC Statute set forth in Indiana Code ("I.C.") §8-1-39-9?

A12. Yes. The Commission approved IPL's TDSIC Plan under I.C. § 8-1-39-10 ("Section 10") and cost recovery pursuant to I.C. § 8-1-39-9 ("Section 9"). In this proceeding, IPL is seeking cost recovery pursuant to Section 9.

Q13. Has IPL used the customer class revenue allocation factors based on firm load approved in IPL's most recent basic rate case order as required by Section 9(a)(1)?

A13. Yes. This issue was resolved in IPL's most recent basic rate case. IPL Witness Coklow used the approved TDSIC allocation factors in IPL Attachment NHC-2 to calculate the appropriate customer class factors (IURC Cause No. 45029, Settling Parties Joint Exhibit 1 Settlement Attachment E).

Q14. Has IPL included its TDSIC Plan as part of this filing as required by Section 9(a)2?

A14. Yes. As noted above, IPL's TDSIC Plan was approved by the Commission's order dated March 4, 2020 in Cause No. 45264 ("IPL TDSIC Plan Order"). IPL's TDSIC Plan was admitted to the record in that Cause as IPL Exhibit 2. This was a comprehensive exhibit. Appendix 8.7 to this exhibit set forth the cost estimates and year detail and plan projects by FERC account (sortable list). IPL's Petition included a request for administrative notice to the IPL TDSIC Plan. For administrative efficiency IPL proposes that going forward, IPL's TDSIC Rider filings include Appendix 8.7 only to comply with the Section 9(a) requirement that the petition include the public utility's TDSIC Plan. IPL Witness Shields sponsors IPL Confidential Attachment JWS-1, which reconciles the cost estimates presented in Appendix 8.7 of IPL's approved TDSIC Plan with actual TDSIC capital costs as of March 31, 2020.

Q15. Are the TDSIC projects included for recovery eligible transmission, distribution, and storage system improvements under I.C. § 8-1-39-2?

A15. Yes. The projects implemented in IPL's TDSIC Plan were undertaken for the purpose of safety, reliability, or system modernization and were found by the Commission to constitute eligible transmission, distribution, or storage system improvements within I.C.

§ 8-1-39-2. IPL TDSIC Plan Order, p.21. The Commission Order authorized TDSIC treatment for the projects in IPL's TDSIC Plan in accordance with I.C. § 8-1-39-10(b). IPL TDSIC Plan Order, p. 24.

Q16. Were any of the TDSIC projects included for recovery in this Cause in IPL's rate base in IURC Cause No. 45029 (IPL's most recent rate case)?

A16. No. These are new projects which have not previously been included in IPL's rate base. The rate base cutoff in IPL's most recent rate case was June 30, 2017 with major project additions and certain net post-test year generation additions through April 2018. TDSIC Plan Development costs did not begin until May 2018. Additionally, the Order approving IPL's TDSIC Plan confirms that the proposed projects "were not included in IPL's most recent rate case." IPL TDSIC Plan Order, p. 21.

Q17. I.C. § 8-1-39-9(d) states that a public utility may not file a petition under I.C. § 8-1-39-9(a) within nine (9) months after the date on which the Commission issued an order changing Petitioner's basic rates and charges. When was IPL's most recent electric rate case order issued?

A17. The final order in IPL's most recent rate case (Cause No. 45029) is dated October 31, 2018, which is more than nine months prior to the filing of this TDSIC.

Q18. Does IPL intend to file a basic rates and charges petition with the Commission prior to the expiration of the 7-Year TDSIC Plan, as required by I.C. § 8-1-39-9(e)?

A18. Yes, IPL intends to petition the Commission for review and approval of its basic rates and charges prior to the expiration of the 7-year TDSIC Plan.

Q19. I.C. § 8-1-39-9(f) states that a public utility may file a Section 9 petition not more than one time every six months. Please provide an overview of IPL's planned TDSIC rider calendar.

A19. The Order approving IPL's TDSIC Plan states that "IPL shall file its TDSIC Plan updates and TDSIC rate updates separately on an annual basis, staggered six months from each other, as subdockets in this Cause under the cause number 45264 TDSIC X, with its first tracker filed on or before July 1, 2020." IPL TDSIC Plan Order, p. 29. The following schedule meets this requirement:

Table 1: IPL's TDSIC Rider Schedule

Filing	Type	Actual Costs Cutoff	Filing Date	Order Date	Rates Effective Period	Reconciliation Period
TDSIC 1	Rate	Mar 31, 2020	Mid Jun 2020	Oct 2020	Nov 2020 – Oct 2021	
TDSIC 2	Plan Update		Mid Dec 2020	Apr 2021		
TDSIC 3	Rate	Mar 31, 2021	Mid Jun 2021	Oct 2021	Nov 2021 – Oct 2022	
TDSIC 4	Plan Update		Mid Dec 2021	Apr 2022		
TDSIC 5	Rate	Mar 31, 2022	Mid Jun 2022	Oct 2022	Nov 2022 – Oct 2023	Nov 2020 – Oct 2021
TDSIC 6	Plan Update		Mid Dec 2022	Apr 2023		
TDSIC 7	Rate	Mar 31, 2023	Mid Jun 2023	Oct 2023	Nov 2023 – Oct 2024	Nov 2021 – Oct 2022
TDSIC 8	Plan Update		Mid Dec 2023	Apr 2024		
TDSIC 9	Rate	Mar 31, 2024	Mid Jun 2024	Oct 2024	Nov 2024 – Oct 2025	Nov 2022 – Oct 2023
TDSIC 10	Plan Update		Mid Dec 2024	Apr 2025		
TDSIC 11	Rate	Mar 31, 2025	Mid Jun 2025	Oct 2025	Nov 2025 – Oct 2026	Nov 2023 – Oct 2024
TDSIC 12	Plan Update		Mid Dec 2025	Apr 2026		
TDSIC 13	Rate	Mar 31, 2026	Mid Jun 2026	Oct 2026	Nov 2026 – Oct 2027	Nov 2024 – Oct 2025
TDSIC 14	Rate	Mar 31, 2027	Mid Jun 2027	Oct 2027	Nov 2027 – Oct 2028	Nov 2025 – Oct 2026
TDSIC 15	Rate	Mar 31, 2028	Mid Jun 2028	Oct 2028	Nov 2028 – Oct 2029	Nov 2026 – Oct 2027

Q20. Please describe IPL's planned TDSIC 2 Plan Update filing.

A20. In its TDSIC 2 Plan Update filing, IPL will present the progress of the TDSIC projects and compare spending levels to the previously approved TDSIC Plan estimates. IPL will also present any proposed changes to the Plan and provide specific justification for the Commission to approve the recovery of costs in excess of approved estimates. IPL TDSIC Plan Order, p. 29.

IPL will also update certain cost estimates based on refined engineering performed for certain projects. Specifically, IPL plans to present Class 2 cost estimates for certain TDSIC Year 3 projects. Due to travel restrictions and social distancing requirements of IPL and contractor personnel caused by the COVID-19 pandemic, Class 2 engineering of some of these projects is expected to be delayed and likely not available for presentation in the December 2020 filing. In order to provide timely Plan updates and adhere to the Order requirements outlining the six-month staggering of TDSIC Plan Update rider filings, IPL will file TDSIC 2 as scheduled in December 2020, and proposes to file supplemental information that will include the remaining Class 2 cost estimates for Year 3 projects when complete. IPL anticipates the timing of the TDSIC supplemental filing to be in the first half of 2021. IPL Witness Shields discusses the anticipated delay in engineering estimates in more detail. IPL will know more closer to the filing of TDSIC 2 and will seek to discuss procedural details with the OUCC.

Q21. Did IPL meet with the OUCC and interested stakeholders prior to filing its petition in this Cause?

A21. Yes. IPL met with the OUCC and interested stakeholders to preview the accounting and ratemaking schedules and to discuss topics of interest.

Q22. Please summarize the findings and approvals made by the Commission in the IPL TDSIC Plan Order which are reflected in this TDSIC rate filing.

A22. The Commission Order included the following related to the accounting ratemaking in the TDSIC Rider:

- authorized TDSIC treatment for the improvements described in IPL's TDSIC Plan including costs incurred starting on August 1, 2019. IPL TDSIC Plan Order, p. 24.
- found the best cost estimate of the eligible improvements included in the Plan is the $1.2 billion estimate provided by IPL. IPL TDSIC Plan Order, p. 29.
- authorized IPL to defer post-in-service TDSIC Plan costs on an interim basis until such costs are included in TDSIC Rider rates or in future base rates. IPL TDSIC Plan Order, p. 29.
- approved IPL's request for authority to defer its plan development costs for recovery via IPL's future TDSIC tracker pursuant to I.C. § 8-1-39-9 over a three-year amortization period. IPL TDSIC Plan Order, p. 29.
- approved IPL's proposals to utilize the applicable depreciation rates approved in its most recent rate case and to recover depreciation prospectively. IPL TDSIC Plan Order, p. 29.
- directed IPL to remove the gross up for taxes associated with the 20% deferred regulatory asset from future filings. IPL TDSIC Plan Order, p. 25.
- found it appropriate to explore a reasonable adjustment when determining the WACC in TDSIC 1 to address the OUCC's depreciation netting concern and the IPL Industrial Group's (IG) concerns with the shifting of risks based on the plan. IPL TDSIC Plan Order, p. 27.

Q23. Has IPL complied with the accounting and ratemaking treatment approved in the TDSIC Plan Order in developing the proposed TDSIC factors?

A23. Yes. IPL Witness Coklow presents the accounting schedules and utilized the accounting treatment discussed above in determining the applicable TDSIC Rider factors.

Q24. What specific costs were included in the development of the proposed TDSIC factors for which IPL is requesting Commission approval?

A24. IPL included eligible TDSIC Costs as defined under I.C. § 8-1-39-7, including depreciation expense, property taxes, and pretax returns. IPL also included the amortization of plan development costs as authorized in the TDSIC Plan filing order discussed above.

Q25. How is IPL's treatment of income taxes on the deferred regulatory asset in this filing compliant with the Commission's TDSIC Plan Order?

A25. IPL has recorded the 20% deferral related to income taxes to a separate regulatory asset account to facilitate the treatment ordered by the Commission. In the IPL TDSIC Plan Order (p. 25), the Commission stated:

> **Recovery of Income Taxes on Deferred Regulatory Asset.** Mr. Blakley raised a concern that IPL should not recover income taxes on the same earnings twice when the 20% deferred regulatory asset is included in IPL' s next general rate case. We agree and find that IPL shall remove the gross up for taxes associated with the 20% deferred regulatory asset from future filings.

IPL Witness Coklow identified the portion of the deferral for income tax and presented the balance separately on IPL Attachment NHC-10. IPL will continue to reflect the deferred regulatory asset related to income tax recovery on this schedule which can then be excluded from the gross up of taxes in a future rate case filing.

3. "OTHER INFORMATION" IN CONSIDERING THE APPROPRIATE PRETAX RETURN

Q26. Please explain how IPL addressed the OUCC's concern that the TDSIC Rider revenues for new assets should be offset with the discontinued depreciation expense on the retirement of the replaced assets. IURC Cause No. 45264 Order pp. 8-9, 26-27)?

A26. As an initial matter, I continue to disagree with the OUCC's position that IPL's previous proposal is unreasonable. I addressed this in my rebuttal in Cause No. 45264. That being said, to address this concern and to reduce controversy, IPL calculated depreciation expense on the retired and replaced assets and has included that depreciation expense amount as a credit to the depreciation expense recovery sought in this filing. The netting of depreciation expense is presented on IPL Attachment NHC-6 Line 2. This netting of depreciation is calculated in the same way IPL has implemented the netting of depreciation in past Environmental Compliance Cost Recovery Adjustment filings for Mercury Air Toxics Standard ("MATS") equipment. The effect of this adjustment is a reduction in the revenue that would otherwise have been recovered through the TDSIC rider, effectively reducing IPL's return on the new assets as compared to not reflecting the depreciation credit. This treatment sufficiently addresses the concern of netting depreciation expense on the assets retired as part of the TDSIC Plan. As discussed below, no adjustment to the pretax return is necessary.

Q27. Please summarize the IG's concern that the TDSIC mechanism "shifts risks based on plan approval." (IPL TDSIC Plan Order pp. 10 & 27)

A27. The IPL TDSIC Plan Order (p. 10) reflects that the IG's witness contended that "IPL's ROE approved in its most recent rate case reflects the risk of utility without a TDSIC plan and TDSIC plan pre-approval greatly reduces IPL's risk profile." I would note that the IG witness provided no analysis to support his summary contention. Cause No. 45264, IG Witness Collin p. 19. In my rebuttal in the Plan case, I indicated that this concern was premature, explaining that the IPL did not seek approval of revenue requirement at that time. As a result, the Company did not attempt to rebut this concern in the Plan case.

Q28. What does the term "risk profile" mean?

A28. I understand the IG's use of the term "risk profile" to refer to the threats to which an organization is exposed. In the Plan case, the IG witness viewpoint was that unlike the status quo, once the TDSIC Plan is approved, IPL will no longer face risk of disallowances or non-recovery.[1] IG Witness Collins said the only check and balance is with the Commission when the TDSIC Plan is presented for approval.[2] I disagree that it is appropriate to look only at risk-reducing factors and not also take into consideration factors that increase risk, such as the size of the capital expenditure needed to respond to the statutory objective of using a multi-year investment plan to address infrastructure needs systemically, which in turn provides efficiency and other benefits.[3] The undertaking of a capital plan the magnitude of IPL's TDSIC Plan increases capital expenditures beyond what would otherwise be undertaken. Without an approved TDSIC tracker, this would put pressure on IPL's 1) ability to satisfy credit metrics (operating cashflows metrics, EBITDA metrics, and debt metrics), 2) ability to issue debt at attractive rates, and 3) ability to maintain a balanced capital structure. Timely cost recovery through the TDSIC helps to offset these pressures.

Q29. Does Commission approval of IPL's TDSIC Plan mean that the Company will no longer face any risk of disallowance or non-recovery?

A29. No. The TDSIC Statute provides that an approved TDSIC Plan is eligible for 80% timely cost recovery and 20% cost deferral to a subsequent rate case as set forth in Section 9 of

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[1] Cause No. 45264, IG Witness Collins p. 19.

[2] Cause No. 45264, IG Witness Collin p. 19.

[3] Cause No. 45264, IPL Witness Bentley Direct Testimony p. 9.

the Statute. While I agree that the 80% timely cost recovery is important to maintaining the financial health of the utility, I disagree that the statutory "TDSIC treatment" means the Company will no longer face any risk of disallowance or non-recovery or that there are no other checks and balances. As explained in the IPL TDSIC Plan Order (p. 23):

> After approval of a TDSIC plan, Ind. Code § 8-1-39-9 establishes procedures for TDSIC trackers, providing that "[a]ctual capital expenditures and TDSIC costs that exceed the approved capital expenditures and TDSIC costs require specific justification by the public utility and specific approval by the commission before being authorized for recovery in customer rates."

I would add that the IG has appealed the Commission's Order approving IPL's TDSIC Plan. The Industrial Group's appeals of other cases have resulted in other Commission TDSIC orders being vacated. Thus, while the Company is moving forward with the TDSIC Plan, doing so is not without risk given the Industrial Group's pending appeal.

Q30. Please discuss whether Commission approval of the IPL TDSIC Plan is "unlike the status quo" as indicated by the IG witness in the Plan proceeding.

A30. The TDSIC Statute has been part of Indiana's utility regulatory framework since 2013 and many other Indiana energy utilities have used this statute. In this regard, the Commission's March 2020 approval of the IPL Plan is not a departure from Indiana's existing a regulatory scheme. Furthermore, it is my understanding that Indiana has long allowed utilities to obtain pre-approval of investments from the Commission. I.C. § 8-1-2-23. Thus, I view the TDSIC Statute as changing the timeliness of cost recovery. Even then, this change is limited to 80% of capital expenditures and TDSIC Costs and is also tied to requirements that the utility defer 20% of its costs and file a basic rate case before expiration of the plan.

I.C. § 8-1-39-9(e). My understanding is that Indiana's utility regulatory framework does not otherwise impose a requirement on how often a utility must file a general rate case.

Thus, to the extent the TDSIC Statute changed the so-called status quo for Indiana ratemaking for T&D capital investment, it did so in two ways (*i.e.* timely cost recovery and a required general rate case). It is unreasonable to consider the impact of the timely cost recovery mechanism in a vacuum. As discussed below, when viewed holistically, a downward adjustment to IPL's TDSIC Rider pretax return is not warranted.

Q31. Is it reasonable to reduce IPL's pre-tax return in the TDSIC Rider in response to the IG's concern summarized above?

A31. No. I disagree that the ratemaking provisions of the TDSIC Statute warrant an adjustment to the Company's Commission's authorized pre-tax return. IPL's basic rates and charges have been reviewed in two recent cases (Cause Nos. 44576 and 45029). The Commission's decisions in these cases were issued March 15, 2016 and October 31, 2018, respectively, well after the enactment of the TDSIC Statute. The general rate case the Company is required to file under the TDSIC Statute, will provide another opportunity for the Commission to review the Company's rates and charges, including its authorized return.

The TDSIC Statute is designed to incentivize the expeditious investment in and improvement and modernization of Indiana's energy delivery system infrastructure. I am not aware instance where the Commission reduced the pre-tax return in a TDSIC Rider where the utility involved had at least one recent rate case.

As discussed above, the netting of depreciation expense reflected in IPL's proposed revenue requirement reduces the revenue IPL will receive and reasonably responds to the

Commission's Order. The netting has the effect of reducing IPL's pre-tax return; no other downward adjustment should be made.

The fact that IPL operates under certain rate adjustment mechanisms (also referred to as trackers) does not distinguish it from other firms in the electric utility industry. In IPL's most recent rate case, IPL's ROE witness explained that the existence of trackers is already reflected in the forward-looking cost of equity analysis because such mechanisms are industry wide:

> Adjustment mechanisms and cost trackers have been increasingly prevalent in the utility industry in recent years. In response to the increasing risk sensitivity of investors to uncertainty over fluctuations in costs and the importance of advancing other public interest goals such as reliability, energy conservation, and safety, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty and align the interest of utilities and their customers through a variety of adjustment mechanisms. Based largely on the expanded use of ratemaking mechanisms to address operational risks and investment recovery, Moody's upgraded most regulated utilities in January 2014. This is consistent with the view that investors perceive the impact of regulatory mechanisms to be an industry-wide factor. Just as a rising tide lifts all boats, ratemaking mechanisms have had an across-the-board impact on risk perceptions for virtually all utilities. (citations omitted)

IPL Witness McKenzie Direct Testimony, pp. 8-9.[4] In that case, IPL Witness McKenzie summarized the regulatory adjustment mechanisms available to the proxy group of electric utilities used to estimate the cost of equity which included infrastructure cost trackers that allow for recovery of new capital investment outside of a traditional rate case as well as a variety of other adjustment clauses. Witness AMM Attachment 3 (included with my testimony as IPL Attachment CAR-5). As shown by this attachment, timely cost recovery

[4] Citing Moody's Investors Service, "US utility sector upgrades driven by stable and transparent regulatory frameworks," *Sector Comment* (Feb. 2, 2014).

mechanisms are common among the proxy companies. IPL Witness McKenzie concluded, "Thus, while the mechanisms approved for IPL by the IURC would be regarded as supportive, investors would not view the risks of IPL as lower than the proxy group in these important respects." IPL Witness McKenzie Direct Testimony, p. 9. Thus, it would be incorrect to conclude that approval of the Company's TDSIC Plan and use of the statutory cost recovery has created a change in the Company's overall risk profile that would cause investors to specifically and measurably revise their return requirements.

Furthermore, the settlement in that recent rate case did not ignore that a TDSIC was available to IPL. To the contrary, the parties (including IG) settled on TDSIC allocation factors which were included in the Commission Order approving the Settlement, (Cause No 45029 Settling Parties Joint Exhibit 1 Settlement Attachment E).

Additionally, when paired with the introduction of a TDSIC Plan, the approval of a TDSIC rate mechanism is credit supportive and maintains the Company's opportunity to earn its previously authorized return. *Without* an approved mechanism to timely recover capital investment and TDSIC Costs related to IPL's TDSIC Plan investment, IPL's opportunity to earn its authorized return and maintain the metrics used to establish its credit rating would diminish.

Q32. Have you considered the Commission's recent discussion and findings on the topic of rate adjustment mechanisms and the utility's cost of equity?

A32. Yes. I reviewed the order in a recent litigated IPL rate case docketed as Cause No. 44576 (IURC 3/16/2016) (p. 42) and a litigated Indiana Michigan Power Company ("I&M") rate case docketed as Cause No. 44075 (IURC 2/13/2013) (p. 43). The order in the I&M case

(p. 31) states that the OUCC witness "did not make a specific adjustment to his COE estimate to recognize the influence of trackers. He explained to the extent that Indiana has trackers that are similar to those provided in other regulatory jurisdictions the effect of trackers is already captured by using an appropriately representative proxy group of state regulated electric utilities." This is consistent with the testimony of IPL Witness McKenzie I discussed above.

In each of these decisions, the Commission also distinguishes rate adjustment mechanisms addressed to regulatory lag from mechanisms addressed to volatility:

> Earnings risk can be seen in both an absolute and a volatility context - the absolute context serves as an effective marker to provide investors with an understanding of the base line earnings available, while the volatility context relates to the ability of the company to perform under a range of real world operating conditions. Trackers that adjust rates for incremental investments or for costs that are nearly certain to be increasing serve to adjust the base line earnings for post rate case changes and address issues primarily associated with regulatory lag. Trackers that adjust rates for cost changes that are more unknown and that are equally likely to decrease or increase address the risk of volatile earnings results. The general effect of these trackers is to reduce the uncertainty of the earnings that an investor can expect.

Id.

In this context, IPL's TDSIC is best described as a tracker that adjust rates for incremental investment and serve to adjusts the base line earnings for post rate case changes and addresses issues primarily associated with regulatory lag. The TDSIC is not a tracker that addresses the risk of volatile earnings. Because the TDSIC tracker is a means of reducing regulatory lag, the approval of the TDSIC should be viewed as maintaining (not reducing) IPL's risk profile. Rather, the TDSIC Rider is a tool that supports IPL's opportunity to earn its previously authorized return.

Finally, neither of the above decisions discussed this issue with respect to the TDSIC Statute or as a means of achieving the objectives of this statute. A Commission decision to reduce IPL's pre-tax return would be contrary to the policy underlying the TDSIC Statute as it would not reasonably incentivize investment in energy delivery infrastructure.

Q33. Does the financial community monitor the Company's financial condition and the Commission's ratemaking decisions?

A33. Yes. The financial community has established metrics that are used to monitor the ongoing financial condition of utility companies, including IPL. The financial community also monitors the regulatory environment in which IPL (and other utilities) operates. The regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk.

For example, Moody's states that 32.50 percent of the weight it gives to various factors considered in its ratings determinations are focused on cash flow because "[f]inancial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers."[5]

[5] Moody's Investors Service, *Rating Methodology; Regulated Electric and Gas Utilities*, June 23, 2017, pp. 4, 20.

S&P's Corporate Criteria Framework shows that cash flow-based metrics are integral to its assessment of the "Financial Risk Profile" which, when combined with the "Business Risk Profile" forms the basis of its rating assessment.[6]

S&P has explained that the regulatory structure is one of the most important factors in its credit rating analyses:

> For a regulated utility company, the regulatory regime in which it operates will influence its performance in profound ways. As such, Standard & Poor's Ratings Services' regulatory advantage assessment - - which informs both our business risk and financial risk scores - - is one of the most important factors in our credit analysis of regulated utilities.
>
> ***
>
> Our assessment of a utility's regulatory regime rests on four pillars: regulatory stability, efficiency of tariff-setting procedures, financial stability, and regulatory independence... We believe these factors strongly influence a utility's credit quality and its ability to recover its costs and earn a timely return.[7]

As I noted above, the Commission has not previously required a downward adjustment in a pre-tax return under the TDSIC Statute where the utility had had recent rate cases. Furthermore, as also discussed above, doing so appears inconsistent with the policy objectives underpinning the Statute and fails to recognize the impact that significant capital investments have on the utility's financial health and the ongoing ability to maintain credit metrics. Thus, a Commission decision to make a downward adjustment to IPL's pre-tax return would be a departure from the Commission's previous actions and could be viewed

[6] Standard & Poor's Ratings Services, *Industry Report Card: The Outlook for U.S. Regulated Utilities Remains Stable on Increasing Capital Spending and Robust Financial Performance*, December 16, 2014, p. 7.

[7] Standard & Poor's Ratings Services, How Regulatory Advantage Scores Can Affect Ratings on Regulated Utilities, April 23, 2015, p. 2.

as a penalty on the Company for its efforts to pursue the goals of the TDSIC Statute in the largest City in the State of Indiana. As discussed below, while Moody's has rated IPL's outlook as "stable", this outlook is based on expectation that Indiana's credit supportive regulatory environment will continue. Moody's has identified a "perceived deterioration" of Indiana's regulatory environment as a factor that would lead to a downgrade.[8]

Q34. You indicated above that rate adjustment mechanisms are viewed by the financial community as credit supportive. Please explain.

A34. S&P has noted that it has "seen many state commissions approve alternative ratemaking techniques to traditional base rate case applications, which help utilities sustain cash flow measures, earning power, and ultimately, credit quality."[9]

In their recent reports regarding IPL, major credit rating agencies refer to tracking mechanisms available to IPL as being viewed as credit supportive.

More specifically, Moody's identified the "[e]xpected increase in capex pending IURC's final approval of the 2020-2027 [TDSIC Plan]" as one of the credit challenges backed by the Company" but noted: "[c]ost recovery mechanisms [that] allow for the recovery of certain cost and investments between rate cases" as a credit strength for IPL.[10] Moody's rated IPL's outlook as "stable" based on expectation that Indiana's credit supportive regulatory environment will continue but identified a "perceived deterioration" of Indiana's regulatory environment as a factor that would lead to a downgrade:

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[8] See QA 34 below referencing Moody's Investors Service, Credit Opinion, Indianapolis Power & Light Company, December 27, 2019, pp. 2-3.

[9] S&P RatingsDirect, *Industry Economic and Ratings Outlook: U.S. Regulated Utilities Expected To Continue On Stable Trajectory In 2013*, January 25, 2013, p. 4.

[10] Moody's Investors Service, Credit Opinion, Indianapolis Power & Light Company, December 27, 2019, p. 2.

> IPL's stable outlook reflects our expectation that its cash flows will continue to benefit from the credit supportive regulatory environment in the state of Indiana, that IPALCO's holding company debt will remain relatively constant, and that IPL's and IPALCO's ratios of cash flow from operations before changes in working capital (CFO pre-W/C) to debt will be sustained in the high and midteens respectively, pending the IURC's approval of IPL's revAMP and IRP programs.
>
> ***
>
> IPL's rating could face downward pressure upon a perceived deterioration of the regulatory environment in Indiana or upon a deterioration in IPL's credit metrics including if its ratio of CFO pre-W/C to debt falls below 18%, on a sustained basis .[11]

The Moody's report explained:

> Our view that the regulatory environment in Indiana is credit supportive considers that IPL's cash flows benefit from several recovery mechanisms that allow the utility to recover operational costs and investments in-between rate cases.[12]

The report added that "cost recovery mechanisms that reduce regulatory lag between rate cases" benefit cash flows and stated that the rating agency assumed that the Commission will allow IPL the 80/20 cost recovery provided in the TDSIC statute.[13]

S&P's rating report also shows that tracking mechanisms are viewed as supporting the utility's opportunity to earn its authorized return:

> The state's regulatory framework supports IPL's overall credit quality. Indiana's stable and transparent regulatory environment provides adequate opportunities to earn close to authorized returns. The company benefits from rate riders, which generally allow for the timely cost recovery of its fuel expenses and most of its incremental environmental capital spending,

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[11] *Id.* pp. 2-3.

[12] *Id.* p. 3.

[13] *Id.* pp. 3-4.

> as well as a Transmission Distribution Storage System Improvement Charge (TDSIC) plan.[14]

A month after the Commission approved IPL's TDSIC Plan, S&P identified the Company's BBB credit rating as stable.[15] The report rated the Company's financial risk as "significant."[16] The same report viewed the Company's business risk as "excellent", citing timely cost recovery as being supportive of IPL's credit quality and supporting generally stable returns:

> Our assessment of IPL's business risk reflects its lower-risk, rate-regulated, vertically integrated electric utility operations. Although IPL has a below-average-sized customer base and generates much of its electricity from its coal-fired units, it effectively manages its regulatory risk under the IURC, earning generally stable returns. IPL further benefits from numerous rate riders, allowing for the timely cost recovery of its fuel expenses and the majority of its incremental environmental capital spending. Additionally, the company recently received approval for its TDSIC plan, which outlines a plan to invest in and earn a tracked return of and on capital spent for about $1.2 billion of investments between 2020 and 2027. We view this development as supportive of IPL's credit quality, since these investments support low risk regulated growth for the company.[17]

The rating agencies are consistent in viewing utilities that have access to tracking mechanisms as credit supportive as it is a sign of a constructive regulatory environment, one of the key considerations given by the rating agencies when assessing utilities.

Q35. What weighted average cost of capital ("WACC") did IPL use to calculate the pretax return component of TDSIC Costs used to calculate the TDSIC rates in this filing?

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[14] S&P Ratings Direct, Indianapolis Power & Light Company, April 14, 2020, p. 2.

[15] *Id.*

[16] *Id.*

[17] *Id.* p. 4.

A35. IPL utilized a WACC of 6.68% which is calculated using IPL's capital structure as of March 31, 2020, actual cost of long-term debt and preferred stock, and IPL's cost of common equity of 9.99% determined by the commission in IPL's most recent general rate proceeding. The WACC used to calculate pretax return is calculated by IPL Witness Coklow in <u>IPL Attachment NHC-5</u>.

In summary, this WACC is appropriately calculated using the cost of common equity determined by the Commission in IPL's most recent general rate proceeding. The "other information" identified in the Commission's IPL TDSIC Plan Order as warranting exploration does not warrant an adjustment to the WACC (or return on equity) for the following reasons:

1.) In this filing, IPL has addressed the concern of netting depreciation expense on the assets retired as part of the TDSIC Plan.

2.) IPL's most recent general rate proceeding in which the Commission approved settlement including a 9.99% ROE was approved in an Order dated October 31, 2018 which is less than two years from this TDSIC rate filing.

3.) IPL's most recent general rate proceeding also contemplated the availability of cost recovery mechanisms to utilities (including capital investment recovery trackers such as TDSIC) and IPL's risk profile, which is not changed based on the approval of a TDSIC.

4.) TDSIC and other timely cost recovery mechanisms are considered credit supportive by credit rating agencies which aids IPL in attracting capital at competitive rates which benefits IPL customers.

4. TDSIC PLAN EFFECTS ON CUSTOMER RATES

Q36. Has IPL calculated the aggregate increase in IPL's total retail revenues as a result of this TDSIC Rider?

A36. Yes. IPL Witness Coklow's testimony and attachments present a calculation of the aggregate increase in IPL's total retail revenues as a result of this TDSIC Rider and demonstrate such increase is less than the 2% statutory TDSIC limit set forth in I.C. § 8-1-39-14. IPL Witness Coklow also presents the proposed TDSIC 1 factors and impact of TDSIC 1 factors on residential bills.

Q37. What period will the TDSIC 1 factors, when approved, remain in effect?

A37. The TDSIC 1 factors, when approved, are planned to go into effect starting with the November 2020 billing cycle and remain in effect until new Rider factors are approved in IPL TDSIC 3, which is expected to be a period of approximately 12 months because IPL TDSIC 3 will seek approval of new factors for the November 2021 billing cycle.

Q38. Please identify the documents that have been marked for purposes of identification as IPL Attachment CAR-1 through 4.

A38. IPL Attachment CAR-1 presents IPL's TDSIC Plan projected effects on retail rates and charges over the seven-year TDSIC Plan period. This attachment presents an estimate of the factors over the Plan period based on the current TDSIC project costs estimates and timing. I utilized the same revenue requirements calculation presented in the TDSIC Plan approval filing to estimate the impact of the TDSIC Plan on revenues with the following updates:

- I updated the estimate to recognize the rate base cutoff dates on March 31 for the rider filings.
- I also reflected the netting of depreciation expense on the retired and replaced assets as a credit to the depreciation expense recovery.
- Additionally, I applied the allocation factors and IPL's most recent volume forecast to estimate the effect the TDSIC Plan has on customer rates and charges.

IPL Attachment CAR-2 calculates IPL's TDSIC Plan projected rate base and depreciation expense utilized to calculate the rate impact in IPL Attachment CAR-1.

IPL Attachment CAR-3 calculates IPL's TDSIC Plan projected property tax expense utilized to calculate the rate impact in IPL Attachment CAR-1.

IPL Attachment CAR-4 presents IPL's TDSIC Plan projected depreciation expense on the retired and replaced assets to include as a credit in calculating the rate impact in IPL Attachment CAR-1.

Q39. What are the projected effects of the seven-year Plan impact on retail rates and charges?

A39. The projected effects are presented as follows and further detailed in IPL Attachment CAR-1 and presented below in Table 2.

Table 2: Projected effects of IPL's TDSIC Plan on retail rates and charges.

	TDSIC 1	TDSIC 3	TDSIC 5	TDSIC 7	TDSIC 9	TDSIC 11	TDSIC 13	TDSIC 14
Rate Base Cutoff	3/31/20	3/31/21	3/31/22	3/31/23	3/31/24	3/31/25	3/31/26	3/31/27
Rate Period	Nov 20-Oct 21	Nov 21-Oct 22	Nov 22-Oct 23	Nov 23-Oct 24	Nov 24-Oct 25	Nov 25-Oct 26	Nov 26-Oct 27	Nov 27-Oct 28
TDSIC Revenue Requirement ($M)	$ 4.2	$ 16.1	$ 32.9	$ 51.5	$ 71.6	$ 89.0	$ 104.1	$ 112.8
Total Revenue Change[1]	0.3%	0.8%	1.1%	1.2%	1.3%	1.1%	1.0%	0.6%
Estimated Rates ($/kWh)								
Residential	$ 0.000440	$ 0.001703	$ 0.003440	$ 0.005337	$ 0.007345	$ 0.008999	$ 0.010403	$ 0.011087
Small C&I	$ 0.000365	$ 0.001420	$ 0.002885	$ 0.004520	$ 0.006282	$ 0.007804	$ 0.009133	$ 0.009889
Large C&I - Secondary	$ 0.000146	$ 0.000867	$ 0.001766	$ 0.002770	$ 0.003850	$ 0.004784	$ 0.005580	$ 0.006055
Large C&I - Primary	$ 0.000226	$ 0.000570	$ 0.001163	$ 0.001831	$ 0.002566	$ 0.003222	$ 0.003775	$ 0.004139
Lighting	$ 0.000362	$ 0.001350	$ 0.002793	$ 0.004396	$ 0.006175	$ 0.007745	$ 0.009190	$ 0.010027

[1] Based on Total Retail Revenues per IPL Attachment NHC-11

5. CONCLUSION

Q40. In your opinion is the accounting and ratemaking relief sought by IPL in this Cause reasonable?

A40. Yes.

Q41. Does that conclude your prepared verified direct testimony?

A41. Yes.

VERIFICATION

I, Chad A. Rogers, Senior Program Manager, affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

Dated June 18, 2020.

Chad A. Rogers

Chad A. Rogers

INDIANAPOLIS POWER & LIGHT COMPANY
TRANSMISSION DISTRIBUTION STORAGE SYSTEM IMPROVEMENT CHARGE (TDSIC)
TDSIC Plan Estimated Annual Revenue Requirement

Line		(B)	(C)	(D)	(E)	(F)	(G)	(H)	
	TDSIC	**TDSIC 3**	**TDSIC 5**	**TDSIC 7**	**TDSIC 9**	**TDSIC 11**	**TDSIC 13**	**TDSIC 14**	
	Rate Base Cutoff	**3/31/21**	**3/31/22**	**3/31/23**	**3/31/24**	**3/31/25**	**3/31/26**	**3/31/27**	
	Rate Period	**Nov 21-Oct 22**	**Nov 22-Oct 23**	**Nov 23-Oct 24**	**Nov 24-Oct 25**	**Nov 25-Oct 26**	**Nov 26-Oct 27**	**Nov 27-Oct 28**	**Reference**
	Transmission Revenue Requirement Calculation:								
	Return on Rate Base Annual Revenue Requirement:								
1	Rate Base	$ 31,959,484	$ 60,907,755	$ 94,119,045	$ 127,382,719	$ 156,583,423	$ 171,960,164	$ 198,415,324	Attachment CAR-2
2	Pre-Tax WACC	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	IPL Attachment NHC-5 p. 3
3	Allowed Return on TDSIC Utility Plant	$ 2,134,894	$ 4,068,638	$ 6,287,152	$ 8,509,166	$ 10,459,773	$ 11,486,939	$ 13,254,144	Line 1 x Line 2
4	Revenue Conversion	1.23886	1.23886	1.23886	1.23886	1.23886	1.23886	1.23886	IPL Attachment NHC-6
5	Total Return on Rate Base Annual Revenue Requirement	$ 2,644,834	$ 5,040,473	$ 7,788,901	$ 10,541,665	$ 12,958,194	$ 14,230,709	$ 16,420,028	Line 3 x Line 4
	Incremental Expenses Annual Revenue Requirement:								
6	Property Tax Expense - Annualized	$ 257,920	$ 907,148	$ 1,653,252	$ 2,461,950	$ 3,215,065	$ 3,808,136	$ 3,808,136	Attachment CAR-3
7	Depreciation Expense - Annualized	$ 245,658	$ 787,936	$ 1,441,159	$ 2,177,626	$ 2,904,788	$ 3,551,653	$ 4,186,572	Attachment CAR-2
8	Depreciation Expense on Retirements - Credit	$ (28,695)	$ (100,222)	$ (160,406)	$ (183,921)	$ (201,436)	$ (221,956)	$ (241,590)	Attachment CAR-4
9	Amortization Expense - Plan Development Costs	$ 137,259	$ 137,259	$ -	$ -	$ -	$ -	$ -	IPL Attachment NHC-6
10	Total Incremental Expenses before Revenue Conversion	$ 612,142	$ 1,732,121	$ 2,934,005	$ 4,455,655	$ 5,918,417	$ 7,137,832	$ 7,753,117	Line 6 + Line 7 + Line 8 + Line 9
11	Revenue Conversion	1.01995	1.01995	1.01995	1.01995	1.01995	1.01995	1.01995	IPL Attachment NHC-6
12	Total Incremental Expenses Annual Revenue Requirement	$ 624,354	$ 1,766,677	$ 2,992,538	$ 4,544,545	$ 6,036,490	$ 7,280,231	$ 7,907,792	Line 10 x Line 11
13	**Total Annual Revenue Requirement**	$ 3,269,188	$ 6,807,150	$ 10,781,440	$ 15,086,210	$ 18,994,683	$ 21,510,941	$ 24,327,820	Line 5 + Line 12
14	**Revenue Requirement Recoverable in TDSIC Rider (80%)**	**$ 2,615,351**	**$ 5,445,720**	**$ 8,625,152**	**$ 12,068,968**	**$ 15,195,747**	**$ 17,208,753**	**$ 19,462,256**	Line 13 x 80%

Line		(B)	(C)	(D)	(E)	(F)	(G)	(G)	(H)
	TDSIC	**TDSIC 3**	**TDSIC 5**	**TDSIC 7**	**TDSIC 9**	**TDSIC 11**	**TDSIC 13**	**TDSIC 14**	
	Rate Base Cutoff	**3/31/21**	**3/31/22**	**3/31/23**	**3/31/24**	**3/31/25**	**3/31/26**	**3/31/27**	
	Rate Period	**Nov 21-Oct 22**	**Nov 22-Oct 23**	**Nov 23-Oct 24**	**Nov 24-Oct 25**	**Nov 25-Oct 26**	**Nov 26-Oct 27**	**Nov 27-Oct 28**	**Reference**
	Distribution Revenue Requirement Calculation:								
	Return on Rate Base Annual Revenue Requirement:								
15	Rate Base	$ 152,698,568	$ 279,798,342	$ 429,393,259	$ 579,072,934	$ 700,242,713	$ 827,018,320	$ 893,954,448	Attachment CAR-2
16	Pre-Tax WACC	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	IPL Attachment NHC-5 p. 3
17	Allowed Return on TDSIC Utility Plant	$ 10,200,264	$ 18,690,529	$ 28,683,470	$ 38,682,072	$ 46,776,213	$ 55,244,824	$ 59,716,157	Line 15 x Line 16
18	Revenue Conversion	1.23886	1.23886	1.23886	1.23886	1.23886	1.23886	1.23886	IPL Attachment NHC-6
19	Total Return on Rate Base Annual Revenue Requirement	$ 12,636,699	$ 23,154,949	$ 35,534,803	$ 47,921,672	$ 57,949,179	$ 68,440,602	$ 73,979,958	Line 17 x Line 18
	Incremental Expenses Annual Revenue Requirement:								
20	Property Tax Expense - Annualized	$ 1,406,618	$ 4,486,267	$ 7,811,942	$ 11,542,401	$ 14,833,269	$ 17,457,302	$ 17,457,302	Attachment CAR-3
21	Depreciation Expense - Annualized	$ 2,468,877	$ 6,709,853	$ 11,327,281	$ 16,454,700	$ 21,225,220	$ 24,781,988	$ 27,623,552	Attachment CAR-2
22	Depreciation Expense on Retirements - Credit	$ (330,227)	$ (904,382)	$ (1,430,612)	$ (1,964,954)	$ (2,471,394)	$ (2,888,395)	$ (3,188,687)	Attachment CAR-4
23	Amortization Expense - Plan Development Costs	$ 647,080	$ 647,080	$ -	$ -	$ -	$ -	$ -	IPL Attachment NHC-6
24	Total Incremental Expenses before Revenue Conversion	$ 4,192,349	$ 10,938,818	$ 17,708,611	$ 26,032,148	$ 33,587,094	$ 39,350,895	$ 41,892,167	Line 20 + Line 21 + Line 22+ Line 23
25	Revenue Conversion	1.01995	1.01995	1.01995	1.01995	1.01995	1.01995	1.01995	IPL Attachment NHC-6
26	Total Incremental Expenses Annual Revenue Requirement	$ 4,275,986	$ 11,157,048	$ 18,061,898	$ 26,551,489	$ 34,257,157	$ 40,135,945	$ 42,727,916	Line 24 x Line 25
27	**Total Annual Revenue Requirement**	$ 16,912,685	$ 34,311,997	$ 53,596,701	$ 74,473,161	$ 92,206,336	$ 108,576,548	$ 116,707,874	Line 19 + Line 26
28	**Revenue Requirement Recoverable in TDSIC Rider (80%)**	**$ 13,530,148**	**$ 27,449,597**	**$ 42,877,361**	**$ 59,578,529**	**$ 73,765,069**	**$ 86,861,238**	**$ 93,366,299**	Line 27 x 80%

Line		(B)	(C)	(D)	(E)	(F)	(G)	(G)	(H)
	TDSIC	**TDSIC 3**	**TDSIC 5**	**TDSIC 7**	**TDSIC 9**	**TDSIC 11**	**TDSIC 13**	**TDSIC 14**	
	Rate Base Cutoff	**3/31/21**	**3/31/22**	**3/31/23**	**3/31/24**	**3/31/25**	**3/31/26**	**3/31/27**	
	Rate Period	**Nov 21-Oct 22**	**Nov 22-Oct 23**	**Nov 23-Oct 24**	**Nov 24-Oct 25**	**Nov 25-Oct 26**	**Nov 26-Oct 27**	**Nov 27-Oct 28**	**Reference**
	Total TDSIC Revenue Requirement Calculation:								
	Return on Rate Base Annual Revenue Requirement:								
29	Rate Base	$ 184,658,051	$ 340,706,097	$ 523,512,304	$ 706,455,653	$ 856,826,136	$ 998,978,485	$ 1,092,369,771	Attachment CAR-2
30	Pre-Tax WACC	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	IPL Attachment NHC-5 p. 3
31	Allowed Return on TDSIC Utility Plant	$ 12,335,158	$ 22,759,167	$ 34,970,622	$ 47,191,238	$ 57,235,986	$ 66,731,763	$ 72,970,301	Line 29 x Line 30
32	Revenue Conversion	1.23886	1.23886	1.23886	1.23886	1.23886	1.23886	1.23886	IPL Attachment NHC-6
33	Total Return on Rate Base Annual Revenue Requirement	$ 15,281,534	$ 28,195,422	$ 43,323,705	$ 58,463,337	$ 70,907,373	$ 82,671,312	$ 90,399,987	Line 31 x Line 32
	Incremental Expenses Annual Revenue Requirement:								
34	Property Tax Expense - Annualized	$ 1,664,538	$ 5,393,415	$ 9,465,194	$ 14,004,351	$ 18,048,334	$ 21,265,437	$ 21,265,437	Attachment CAR-3
35	Depreciation Expense - Annualized	$ 2,714,535	$ 7,497,789	$ 12,768,441	$ 18,632,327	$ 24,130,008	$ 28,333,641	$ 31,810,124	Attachment CAR-2
36	Depreciation Expense on Retirements - Credit	$ (358,922)	$ (1,004,605)	$ (1,591,018)	$ (2,148,875)	$ (2,672,830)	$ (3,110,351)	$ (3,430,277)	Attachment CAR-4
37	Amortization Expense - Plan Development Costs	$ 784,339	$ 784,339	$ -	$ -	$ -	$ -	$ -	IPL Attachment NHC-6
38	Total Incremental Expenses before Revenue Conversion	$ 4,804,490	$ 12,670,939	$ 20,642,616	$ 30,487,802	$ 39,505,512	$ 46,488,727	$ 49,645,284	Line 6 + Line 7 + Line 8 + Line 9
39	Revenue Conversion	1.01995	1.01995	1.01995	1.01995	1.01995	1.01995	1.01995	IPL Attachment NHC-6
40	Total Incremental Expenses Annual Revenue Requirement	$ 4,900,340	$ 12,923,724	$ 21,054,436	$ 31,096,034	$ 40,293,646	$ 47,416,177	$ 50,635,708	Line 38 x Line 39
41	**Total Annual Revenue Requirement**	$ 20,181,874	$ 41,119,146	$ 64,378,141	$ 89,559,371	$ 111,201,020	$ 130,087,489	$ 141,035,695	Line 33 + Line 40
42	**Revenue Requirement Recoverable in TDSIC Rider (80%)**	**$ 16,145,499**	**$ 32,895,317**	**$ 51,502,513**	**$ 71,647,496**	**$ 88,960,816**	**$ 104,069,991**	**$ 112,828,556**	Line 41 x 80%

INDIANAPOLIS POWER & LIGHT COMPANY
TRANSMISSION DISTRIBUTION STORAGE SYSTEM IMPROVEMENT CHARGE (TDSIC)
TDSIC Plan Estimated Retail Rates

		(B)	(C)	(D)	(E)	(F)	(G)	(G)	(H)
	TDSIC	TDSIC 3	TDSIC 5	TDSIC 7	TDSIC 9	TDSIC 11	TDSIC 13	TDSIC 14	
	Rate Base Cutoff	3/31/21	3/31/22	3/31/23	3/31/24	3/31/25	3/31/26	3/31/27	
Line	Rate Period	Nov 21-Oct 22	Nov 22-Oct 23	Nov 23-Oct 24	Nov 24-Oct 25	Nov 25-Oct 26	Nov 26-Oct 27	Nov 27-Oct 28	Reference
1	**Total Revenue Requirement Rider**	$ 16,145,499	$ 32,895,317	$ 51,502,513	$ 71,647,496	$ 88,960,816	$ 104,069,991	$ 112,828,556	P. 1 Line 41
2	**Rider Revenue Requirement - Transmission**	$ 2,615,351	$ 5,445,720	$ 8,625,152	$ 12,068,968	$ 15,195,747	$ 17,208,753	$ 19,462,256	P. 1 Line 14
3	**Rider Revenue Requirement - Distribution**	$ 13,530,148	$ 27,449,597	$ 42,877,361	$ 59,578,529	$ 73,765,069	$ 86,861,238	$ 93,366,299	P. 1 Line 28
	Allocation Factor - Transmission								
4	Residential	40.50%	40.50%	40.50%	40.50%	40.50%	40.50%	40.50%	CN 45029 Settlement Agreement Att E
5	Small C&I	15.21%	15.21%	15.21%	15.21%	15.21%	15.21%	15.21%	CN 45029 Settlement Agreement Att E
6	Large C&I - Secondary	25.85%	25.85%	25.85%	25.85%	25.85%	25.85%	25.85%	CN 45029 Settlement Agreement Att E
7	Large C&I - Primary	18.04%	18.04%	18.04%	18.04%	18.04%	18.04%	18.04%	CN 45029 Settlement Agreement Att E
8	Lighting	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	CN 45029 Settlement Agreement Att E
	Allocation Factor - Distribution								
10	Residential	57.06%	57.06%	57.06%	57.06%	57.06%	57.06%	57.06%	CN 45029 Settlement Agreement Att E
11	Small C&I	15.84%	15.84%	15.84%	15.84%	15.84%	15.84%	15.84%	CN 45029 Settlement Agreement Att E
12	Large C&I - Secondary	17.95%	17.95%	17.95%	17.95%	17.95%	17.95%	17.95%	CN 45029 Settlement Agreement Att E
13	Large C&I - Primary	8.28%	8.28%	8.28%	8.28%	8.28%	8.28%	8.28%	CN 45029 Settlement Agreement Att E
14	Lighting	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	CN 45029 Settlement Agreement Att E
	Transmission - Revenue Requirement								
15	Residential	$ 1,059,000	$ 2,206,000	$ 3,494,000	$ 4,888,000	$ 6,155,000	$ 6,970,000	$ 7,883,000	Line 2 x Line 4
16	Small C&I	$ 398,000	$ 828,000	$ 1,312,000	$ 1,836,000	$ 2,312,000	$ 2,618,000	$ 2,961,000	Line 2 x Line 5
17	Large C&I - Secondary	$ 676,000	$ 1,408,000	$ 2,230,000	$ 3,120,000	$ 3,928,000	$ 4,448,000	$ 5,031,000	Line 2 x Line 6
18	Large C&I - Primary	$ 472,000	$ 982,000	$ 1,556,000	$ 2,177,000	$ 2,741,000	$ 3,104,000	$ 3,510,000	Line 2 x Line 7
19	Lighting	$ 10,000	$ 22,000	$ 34,000	$ 48,000	$ 61,000	$ 69,000	$ 78,000	Line 2 x Line 8
20	**Total**	$ 2,615,000	$ 5,446,000	$ 8,626,000	$ 12,069,000	$ 15,197,000	$ 17,209,000	$ 19,463,000	Sum Lines 15-19
	Distribution - Revenue Requirement								
21	Residential	$ 7,721,000	$ 15,664,000	$ 24,468,000	$ 33,998,000	$ 42,093,000	$ 49,567,000	$ 53,279,000	Line 3 x Line 10
22	Small C&I	$ 2,143,000	$ 4,348,000	$ 6,792,000	$ 9,437,000	$ 11,685,000	$ 13,759,000	$ 14,789,000	Line 3 x Line 11
23	Large C&I - Secondary	$ 2,429,000	$ 4,929,000	$ 7,699,000	$ 10,697,000	$ 13,244,000	$ 15,596,000	$ 16,764,000	Line 3 x Line 12
24	Large C&I - Primary	$ 1,121,000	$ 2,273,000	$ 3,551,000	$ 4,935,000	$ 6,110,000	$ 7,194,000	$ 7,733,000	Line 3 x Line 13
25	Lighting	$ 116,000	$ 236,000	$ 368,000	$ 511,000	$ 633,000	$ 746,000	$ 802,000	Line 3 x Line 14
26	**Total**	$ 13,530,000	$ 27,450,000	$ 42,878,000	$ 59,578,000	$ 73,765,000	$ 86,862,000	$ 93,367,000	Sum Lines 21-25
	Total Revenue Requirement								
27	Residential	$ 8,780,000	$ 17,870,000	$ 27,962,000	$ 38,886,000	$ 48,248,000	$ 56,537,000	$ 61,162,000	Line 15 + Line 21
28	Small C&I	$ 2,541,000	$ 5,176,000	$ 8,104,000	$ 11,273,000	$ 13,997,000	$ 16,377,000	$ 17,750,000	Line 16 + Line 22
29	Large C&I - Secondary	$ 3,105,000	$ 6,337,000	$ 9,929,000	$ 13,817,000	$ 17,172,000	$ 20,044,000	$ 21,795,000	Line 17 + Line 23
30	Large C&I - Primary	$ 1,593,000	$ 3,255,000	$ 5,107,000	$ 7,112,000	$ 8,851,000	$ 10,298,000	$ 11,243,000	Line 18 + Line 24
31	Lighting	$ 126,000	$ 258,000	$ 402,000	$ 559,000	$ 694,000	$ 815,000	$ 880,000	Line 19 + Line 25
32	**Total**	$ 16,145,000	$ 32,896,000	$ 51,504,000	$ 71,647,000	$ 88,962,000	$ 104,071,000	$ 112,830,000	Sum Lines 27-31
	TDSIC	TDSIC 3	TDSIC 5	TDSIC 7	TDSIC 9	TDSIC 11	TDSIC 13	TDSIC 14	
	Rate Base Cutoff	3/31/21	3/31/22	3/31/23	3/31/24	3/31/25	3/31/26	3/31/27	
Line	Rate Period	Nov 21-Oct 22	Nov 22-Oct 23	Nov 23-Oct 24	Nov 24-Oct 25	Nov 25-Oct 26	Nov 26-Oct 27	Nov 27-Oct 28	Reference
	Estimated Forecasted Firm Load Volume (MWh)								
33	Residential	5,155,525	5,195,340	5,239,032	5,294,228	5,361,309	5,434,537	5,516,703	IPL Load Forecast
34	Small C&I	1,789,164	1,793,896	1,793,078	1,794,594	1,793,637	1,793,175	1,794,967	IPL Load Forecast
35	Large C&I - Secondary	3,580,334	3,589,004	3,584,686	3,588,756	3,589,762	3,592,276	3,599,307	IPL Load Forecast
36	Large C&I - Primary	2,792,394	2,799,824	2,789,700	2,771,182	2,747,478	2,728,069	2,716,049	IPL Load Forecast
37	Lighting	93,299	92,376	91,452	90,529	89,606	88,682	87,759	IPL Load Forecast
38	**Total**	13,410,716	13,470,439	13,497,948	13,539,289	13,581,791	13,636,739	13,714,785	IPL Load Forecast
	$ per kWh								
39	**Residential**	$ 0.001703	$ 0.003440	$ 0.005337	$ 0.007345	$ 0.008999	$ 0.010403	$ 0.011087	Line 27/Line 33/1,000
40	**Small C&I**	$ 0.001420	$ 0.002885	$ 0.004520	$ 0.006282	$ 0.007804	$ 0.009133	$ 0.009889	Line 28/Line 34/1,000
41	**Large C&I - Secondary**	$ 0.000867	$ 0.001766	$ 0.002770	$ 0.003850	$ 0.004784	$ 0.005580	$ 0.006055	Line 29/Line 35/1,000
42	**Large C&I - Primary**	$ 0.000570	$ 0.001163	$ 0.001831	$ 0.002566	$ 0.003222	$ 0.003775	$ 0.004139	Line 30/Line 36/1,000
43	**Lighting**	$ 0.001350	$ 0.002793	$ 0.004396	$ 0.006175	$ 0.007745	$ 0.009190	$ 0.010027	Line 31/Line 37/1,000

INDIANAPOLIS POWER & LIGHT COMPANY
TRANSMISSION DISTRIBUTION STORAGE SYSTEM IMPROVEMENT CHARGE (TDSIC)
TDSIC Rate Base and Depreciation Expense Estimate Calculation

Line	TDSIC Plan Transmission Assets CapEx Additions (incl AFUDC): FERC Account	(A) Depr Rate	(B) Calendar Year 1 2020	(C) Calendar Year 2 2021	(D) Calendar Year 3 2022	(E) Calendar Year 4 2023	(F) Calendar Year 5 2024	(G) Calendar Year 6 2025	(H) Calendar Year 7 2026	(I)	(J) Total Plan	(K) Reference
1	352.00	2.40%	$ -	$ -	$ -	$ 2,300,385	$ 2,844,940	$ -	$ 2,632,615		$ 7,777,940	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
2	353.00	2.53%	$ 16,542,692	$ 19,582,382	$ 23,096,878	$ 22,073,157	$ 19,302,399	$ 18,615,703	$ 20,407,195		$ 139,620,406	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
3	354.00	1.37%	$ 1,138,320	$ 1,111,147	$ 1,082,432	$ 850,792	$ -	$ -	$ -		$ 4,182,691	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
4	356.00	1.20%	$ 4,765,917	$ 6,881,909	$ 9,502,181	$ 11,200,958	$ 11,497,320	$ 10,679,473	$ 7,601,921		$ 62,129,679	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
5	362.00	1.61%										
6	364.00	2.06%										
7	365.00	2.35%										
8	366.00	2.62%										
9	367.00	2.55%										
10	368.00	0.65%										
11	370.01	19.35%										
12	Total CapEx Additions		$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176	$ 30,641,731		$ 213,710,716	Sum Lines 1-11

Line	Transmission Assets CapEx Additions (incl AFUDC): FERC Account	Depr Rate	TDSIC 1 Thru 3/31/20	TDSIC 3 4/1/20-3/31/21	TDSIC 5 4/1/21-3/31/22	TDSIC 7 4/1/22-3/31/23	TDSIC 9 4/1/23-3/31/24	TDSIC 11 4/1/24-3/31/25	TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Total Plan	Reference
13	352.00	2.40%	$ -	$ -	$ -	$ -	$ 2,300,385	$ 2,844,940	$ -	$ 2,632,615	$ 7,777,940	TDSIC 1: 3/31/2020 Act Balance, Thereafter: Prior Calendar Yr
14	353.00	2.53%	$ -	$ 16,542,692	$ 19,582,382	$ 23,096,878	$ 22,073,157	$ 19,302,399	$ 18,615,703	$ 20,407,195	$ 139,620,406	TDSIC 1: 3/31/2020 Act Balance, Thereafter: Prior Calendar Yr
15	354.00	1.37%	$ -	$ 1,138,320	$ 1,111,147	$ 1,082,432	$ 850,792	$ -	$ -	$ -	$ 4,182,691	TDSIC 1: 3/31/2020 Act Balance, Thereafter: Prior Calendar Yr
16	356.00	1.20%	$ -	$ 4,765,917	$ 6,881,909	$ 9,502,181	$ 11,200,958	$ 11,497,320	$ 10,679,473	$ 7,601,921	$ 62,129,679	TDSIC 1: 3/31/2020 Act Balance, Thereafter: Prior Calendar Yr
17	362.00	1.61%										
18	364.00	2.06%										
19	365.00	2.35%										
20	366.00	2.62%										
21	367.00	2.55%										
22	368.00	0.65%										
23	370.01	19.35%										
24	Total CapEx Additions Placed in Service		$ -	$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176	$ 30,641,731	$ 213,710,716	Sum Lines 13-24
	CWIP Balance 3/31		$ 7,943,370	$ 9,758,213	$ 11,918,982	$ 12,889,940	$ 11,905,948	$ 10,366,782	$ -	$ -		

Line	Transmission Assets 3/31 Utility Plant Balance: FERC Account	Depr Rate	TDSIC 1 3/31/2020	TDSIC 3 3/31/2021	TDSIC 5 3/31/2022	TDSIC 7 3/31/2023	TDSIC 9 3/31/2024	TDSIC 11 3/31/2025	TDSIC 13 3/31/2026	TDSIC 14 3/31/2027	Reference
25	352.00	2.40%	$ -	$ -	$ -	$ -	$ 2,300,385	$ 5,145,325	$ 5,145,325	$ 7,777,940	Line 13 Accumulated
26	353.00	2.53%	$ -	$ 16,542,692	$ 36,125,074	$ 59,221,952	$ 81,295,109	$ 100,597,508	$ 119,213,211	$ 139,620,406	Line 14 Accumulated
27	354.00	1.37%	$ -	$ 1,138,320	$ 2,249,467	$ 3,331,899	$ 4,182,691	$ 4,182,691	$ 4,182,691	$ 4,182,691	Line 15 Accumulated
28	356.00	1.20%	$ -	$ 4,765,917	$ 11,647,826	$ 21,150,007	$ 32,350,965	$ 43,848,285	$ 54,527,758	$ 62,129,679	Line 16 Accumulated
29	362.00	1.61%									
30	364.00	2.06%									
31	365.00	2.35%									
32	366.00	2.62%									
33	367.00	2.55%									
34	368.00	0.65%									
35	370.01	19.35%									
36	Total 3/31 Utility Plant Balance		$ -	$ 22,446,929	$ 50,022,367	$ 83,703,858	$ 120,129,150	$ 153,773,809	$ 183,068,985	$ 213,710,716	Sum Lines 25-36

Line	Transmission Assets Depreciation Expense: FERC Account	Depr Rate	TDSIC 1 Thru 3/31/20	TDSIC 3 4/1/20-3/31/21	TDSIC 5 4/1/21-3/31/22	TDSIC 7 4/1/22-3/31/23	TDSIC 9 4/1/23-3/31/24	TDSIC 11 4/1/24-3/31/25	TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Reference
37	352.00	2.40%	$ -	$ -	$ -	$ -	$ 27,605	$ 89,349	$ 123,488	$ 155,079	(Line 13 x Column A x 50%) + (Prior Line 25 x Column A)
38	353.00	2.53%	$ -	$ 209,265	$ 666,247	$ 1,206,140	$ 1,777,541	$ 2,300,942	$ 2,780,606	$ 3,274,245	(Line 14 x Column A x 50%) + (Prior Line 26 x Column A)
39	354.00	1.37%	$ -	$ 7,797	$ 23,206	$ 38,232	$ 51,475	$ 57,303	$ 57,303	$ 57,303	(Line 15 x Column A x 50%) + (Prior Line 27 x Column A)
40	356.00	1.20%	$ -	$ 28,596	$ 98,482	$ 196,787	$ 321,006	$ 457,196	$ 590,256	$ 699,945	(Line 16 x Column A x 50%) + (Prior Line 28 x Column A)
41	362.00	1.61%									
42	364.00	2.06%									
43	365.00	2.35%									
44	366.00	2.62%									
45	367.00	2.55%									
46	368.00	0.65%									
47	370.01	19.35%									
48	Total Depr Exp - Annualized		$ -	$ 245,658	$ 787,936	$ 1,441,159	$ 2,177,626	$ 2,904,788	$ 3,551,653	$ 4,186,572	

Line	Transmission Assets 3/31 Accumulated Depreciation: FERC Account	Depr Rate	TDSIC 1 3/31/2020	TDSIC 3 3/31/2021	TDSIC 5 3/31/2022	TDSIC 7 3/31/2023	TDSIC 9 3/31/2024	TDSIC 11 3/31/2025	TDSIC 13 3/31/2026	TDSIC 14 3/31/2027	Reference
49	352.00	2.40%	$ -	$ -	$ -	$ -	$ (27,605)	$ (116,953)	$ (240,441)	$ (395,520)	Line 37 Accumulated
50	353.00	2.53%	$ -	$ (209,265)	$ (875,512)	$ (2,081,652)	$ (3,859,193)	$ (6,160,135)	$ (8,940,740)	$ (12,214,985)	Line 38 Accumulated
51	354.00	1.37%	$ -	$ (7,797)	$ (31,004)	$ (69,236)	$ (120,711)	$ (178,014)	$ (235,317)	$ (292,620)	Line 39 Accumulated
52	356.00	1.20%	$ -	$ (28,596)	$ (127,078)	$ (323,865)	$ (644,871)	$ (1,102,066)	$ (1,692,323)	$ (2,392,267)	Line 40 Accumulated
53	362.00	1.61%									
54	364.00	2.06%									
55	365.00	2.35%									
56	366.00	2.62%									
57	367.00	2.55%									
58	368.00	0.65%									
59	370.01	19.35%									
60	Total 3/31 Accum Depr		$ -	$ (245,658)	$ (1,033,594)	$ (2,474,753)	$ (4,652,380)	$ (7,557,168)	$ (11,108,821)	$ (15,295,392)	
	Transmission Assets										
61	3/31 Rate Base			$ 31,959,484	$ 60,907,755	$ 94,119,045	$ 127,382,719	$ 156,583,423	$ 171,960,164	$ 198,415,324	

Line	TDSIC Plan Distribution Assets CapEx Additions (incl AFUDC): FERC Account		(A) Depr Rate	(B) Calendar Year 1 2020	(C) Calendar Year 2 2021	(D) Calendar Year 3 2022	(E) Calendar Year 4 2023	(F) Calendar Year 5 2024	(G) Calendar Year 6 2025	(H) Calendar Year 7 2026	(I)	(J) Total Plan	(K) Reference
1		352.00	2.40%										
2		353.00	2.53%										
3		354.00	1.37%										
4		356.00	1.20%										
5		362.00	1.61%	$ 7,026,754	$ 25,672,321	$ 38,188,063	$ 49,360,078	$ 24,862,469	$ 45,555,289	$ 32,554,913		$ 223,219,887	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
6		364.00	2.06%	$ 39,069,911	$ 34,048,557	$ 47,918,689	$ 52,531,374	$ 44,678,960	$ 49,169,935	$ 46,385,522		$ 313,802,948	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
7		365.00	2.35%	$ 28,815,380	$ 27,771,432	$ 26,078,201	$ 27,620,140	$ 25,686,598	$ 27,204,806	$ 26,696,855		$ 189,873,412	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
8		366.00	2.62%	$ 2,250,626	$ 2,346,110	$ 2,405,220	$ 2,690,012	$ 1,809,774	$ 2,715,591	$ 2,769,903		$ 16,987,236	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
9		367.00	2.55%	$ 13,966,103	$ 13,407,560	$ 14,443,018	$ 14,226,294	$ 14,093,313	$ 14,938,612	$ 14,497,783		$ 99,572,683	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
10		368.00	0.65%	$ 12,521,414	$ 12,200,598	$ 15,845,026	$ 17,725,277	$ 15,147,875	$ 16,296,875	$ 15,682,084		$ 105,419,149	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
11		370.01	19.35%	$ 10,735,674	$ 10,950,388	$ 11,169,395	$ 11,392,783	$ 11,620,639	$ -	$ -		$ 55,868,879	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
12	Total CapEx Additions			$ 114,385,862	$ 126,396,966	$ 156,047,612	$ 175,545,958	$ 137,899,628	$ 155,881,108	$ 138,587,060		$ 1,004,744,194	

Line	Distribution Assets CapEx Additions (incl AFUDC): FERC Account		Depr Rate	TDSIC 1 Thru 3/31/20	TDSIC 3 4/1/20-3/31/21	TDSIC 5 4/1/21-3/31/22	TDSIC 7 4/1/22-3/31/23	TDSIC 9 4/1/23-3/31/24	TDSIC 11 4/1/24-3/31/25	TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Total Plan	Reference
13		352.00	2.40%										
14		353.00	2.53%										
15		354.00	1.37%										
16		356.00	1.20%										
17		362.00	1.61%	$ -	$ 11,251,524	$ 27,502,588	$ 39,999,824	$ 44,450,455	$ 29,095,162	$ 43,032,278	$ 27,888,056	$ 223,219,887	
18		364.00	2.06%	$ 4,281,117	$ 37,235,492	$ 35,886,510	$ 48,027,574	$ 52,751,284	$ 44,786,565	$ 49,509,809	$ 41,324,597	$ 313,802,948	
19		365.00	2.35%	$ 12,312,934	$ 28,082,071	$ 26,461,278	$ 25,914,617	$ 28,391,801	$ 25,504,493	$ 27,674,067	$ 15,532,151	$ 189,873,412	TDSIC 1: 3/31/2020 Actual Balance,
20		366.00	2.62%	$ 250,490	$ 2,234,596	$ 2,279,093	$ 2,422,942	$ 2,558,378	$ 1,980,163	$ 2,791,032	$ 2,470,542	$ 16,987,236	Thereafter: 75% of Prior Calendar Year + 25% of Current Calendar Year -
21		367.00	2.55%	$ 428,901	$ 13,598,438	$ 13,175,258	$ 14,106,029	$ 14,881,648	$ 13,996,222	$ 15,152,199	$ 14,233,987	$ 99,572,683	Change in CWIP
22		368.00	0.65%	$ 231,365	$ 12,233,709	$ 12,572,860	$ 15,962,723	$ 17,821,051	$ 15,098,668	$ 16,493,422	$ 15,005,351	$ 105,419,149	
23		370.01	19.35%	$ -	$ 10,603,114	$ 10,625,300	$ 10,998,762	$ 12,017,531	$ 8,715,479	$ -	$ 2,908,693	$ 55,868,879	
24	Total CapEx Additions Placed in Service			$ 17,504,807	$ 115,238,944	$ 128,502,887	$ 157,432,471	$ 172,872,149	$ 139,176,753	$ 154,652,808	$ 119,363,376	$ 1,004,744,194	
	CWIP Balance 3/31			$ 20,472,274	$ 22,621,968	$ 27,928,709	$ 31,418,437	$ 24,680,663	$ 27,898,909	$ 24,803,697	$ -		

Line	Distribution Assets 3/31 Utility Plant Balance: FERC Account		Depr Rate	TDSIC 1 3/31/2020	TDSIC 3 3/31/2021	TDSIC 5 3/31/2022	TDSIC 7 3/31/2023	TDSIC 9 3/31/2024	TDSIC 11 3/31/2025	TDSIC 13 3/31/2026	TDSIC 14 3/31/2027	Reference
25		352.00	2.40%									
26		353.00	2.53%									
27		354.00	1.37%									
28		356.00	1.20%									
29		362.00	1.61%	$ -	$ 11,251,524	$ 38,754,112	$ 78,753,936	$ 123,204,391	$ 152,299,553	$ 195,331,831	$ 223,219,887	Line 17 Accumulated
30		364.00	2.06%	$ 4,281,117	$ 41,516,609	$ 77,403,119	$ 125,430,694	$ 178,181,977	$ 222,968,542	$ 272,478,351	$ 313,802,948	Line 18 Accumulated
31		365.00	2.35%	$ 12,312,934	$ 40,395,005	$ 66,856,283	$ 92,770,900	$ 121,162,701	$ 146,667,194	$ 174,341,261	$ 189,873,412	Line 19 Accumulated
32		366.00	2.62%	$ 250,490	$ 2,485,086	$ 4,764,178	$ 7,187,121	$ 9,745,499	$ 11,725,662	$ 14,516,694	$ 16,987,236	Line 20 Accumulated
33		367.00	2.55%	$ 428,901	$ 14,027,340	$ 27,202,598	$ 41,308,626	$ 56,190,274	$ 70,186,497	$ 85,338,696	$ 99,572,683	Line 21 Accumulated
34		368.00	0.65%	$ 231,365	$ 12,465,074	$ 25,037,934	$ 41,000,657	$ 58,821,708	$ 73,920,376	$ 90,413,798	$ 105,419,149	Line 22 Accumulated
35		370.01	19.35%	$ -	$ 10,603,114	$ 21,228,414	$ 32,227,176	$ 44,244,707	$ 52,960,186	$ 52,960,186	$ 55,868,879	Line 23 Accumulated
36	Total 3/31 Utility Plant Balance			$ 17,504,807	$ 132,743,751	$ 261,246,638	$ 418,679,109	$ 591,551,258	$ 730,728,010	$ 885,380,818	$ 1,004,744,194	

Line	Distribution Assets Depreciation Expense: FERC Account		Depr Rate	TDSIC 1 Thru 3/31/20	TDSIC 3 4/1/20-3/31/21	TDSIC 5 4/1/21-3/31/22	TDSIC 7 4/1/22-3/31/23	TDSIC 9 4/1/23-3/31/24	TDSIC 11 4/1/24-3/31/25	TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Reference
37		352.00	2.40%									
38		353.00	2.53%									
39		354.00	1.37%									
40		356.00	1.20%									
41		362.00	1.61%	$ -	$ 90,575	$ 402,545	$ 945,940	$ 1,625,765	$ 2,217,807	$ 2,798,433	$ 3,369,341	(Line 17 x Column A x 50%) + (Prior Line 29 x Column A)
42		364.00	2.06%	$ 44,096	$ 471,717	$ 1,224,873	$ 2,089,188	$ 3,127,211	$ 4,131,850	$ 5,103,103	$ 6,038,697	(Line 18 x Column A x 50%) + (Prior Line 30 x Column A)
43		365.00	2.35%	$ 144,677	$ 619,318	$ 1,260,203	$ 1,875,619	$ 2,513,720	$ 3,147,001	$ 3,771,849	$ 4,279,522	(Line 19 x Column A x 50%) + (Prior Line 31 x Column A)
44		366.00	2.62%	$ 3,281	$ 35,836	$ 94,965	$ 156,562	$ 221,817	$ 281,272	$ 343,775	$ 412,701	(Line 20 x Column A x 50%) + (Prior Line 32 x Column A)
45		367.00	2.55%	$ 5,468	$ 184,317	$ 525,682	$ 873,518	$ 1,243,111	$ 1,611,304	$ 1,982,946	$ 2,357,620	(Line 21 x Column A x 50%) + (Prior Line 33 x Column A)
46		368.00	0.65%	$ 752	$ 41,263	$ 121,885	$ 214,625	$ 324,423	$ 431,412	$ 534,086	$ 636,457	(Line 22 x Column A x 50%) + (Prior Line 34 x Column A)
47		370.01	19.35%	$ -	$ 1,025,851	$ 3,079,700	$ 5,171,828	$ 7,398,655	$ 9,404,573	$ 10,247,796	$ 10,529,212	(Line 23 x Column A x 50%) + (Prior Line 35 x Column A)
48	Total Depr Exp - Annualized			$ 198,274	$ 2,468,877	$ 6,709,853	$ 11,327,281	$ 16,454,700	$ 21,225,220	$ 24,781,988	$ 27,623,552	

Line	Distribution Assets 3/31 Accumulated Depreciation: FERC Account		Depr Rate	TDSIC 1 3/31/2020	TDSIC 3 3/31/2021	TDSIC 5 3/31/2022	TDSIC 7 3/31/2023	TDSIC 9 3/31/2024	TDSIC 11 3/31/2025	TDSIC 13 3/31/2026	TDSIC 14 3/31/2027	Reference
49		352.00	2.40%									
50		353.00	2.53%									
51		354.00	1.37%									
52		356.00	1.20%									
53		362.00	1.61%	$ -	$ (90,575)	$ (493,120)	$ (1,439,060)	$ (3,064,824)	$ (5,282,631)	$ (8,081,064)	$ (11,450,405)	Line 41 Accumulated
54		364.00	2.06%	$ (44,096)	$ (515,812)	$ (1,740,685)	$ (3,829,874)	$ (6,957,084)	$ (11,088,934)	$ (16,192,037)	$ (22,230,735)	Line 42 Accumulated
55		365.00	2.35%	$ (144,677)	$ (763,995)	$ (2,024,198)	$ (3,899,817)	$ (6,413,537)	$ (9,560,538)	$ (13,332,388)	$ (17,611,910)	Line 43 Accumulated
56		366.00	2.62%	$ (3,281)	$ (39,117)	$ (134,083)	$ (290,645)	$ (512,462)	$ (793,734)	$ (1,137,509)	$ (1,550,211)	Line 44 Accumulated
57		367.00	2.55%	$ (5,468)	$ (189,786)	$ (715,467)	$ (1,588,985)	$ (2,832,096)	$ (4,443,400)	$ (6,426,346)	$ (8,783,966)	Line 45 Accumulated
58		368.00	0.65%	$ (752)	$ (42,015)	$ (163,900)	$ (378,526)	$ (702,948)	$ (1,134,360)	$ (1,668,446)	$ (2,304,903)	Line 46 Accumulated
59		370.01	19.35%	$ -	$ (1,025,851)	$ (4,105,552)	$ (9,277,380)	$ (16,676,035)	$ (26,080,608)	$ (36,328,404)	$ (46,857,616)	Line 47 Accumulated
60	Total 3/31 Accum Depr			$ (198,274)	$ (2,667,152)	$ (9,377,005)	$ (20,704,286)	$ (37,158,987)	$ (58,384,206)	$ (83,166,195)	$ (110,789,746)	

Line	Distribution Assets								
61	3/31 Year Rate Base		$ 152,698,568	$ 279,798,342	$ 429,393,259	$ 579,072,934	$ 700,242,713	$ 827,018,320	$ 893,954,448

Line	Total TDSIC Assets CapEx Additions (incl AFUDC): FERC Account	(A) Depr Rate	(B) Calendar Year 1 2020	(C) Calendar Year 2 2021	(D) Calendar Year 3 2022	(E) Calendar Year 4 2023	(F) Calendar Year 5 2024	(G) Calendar Year 6 2025	(H) Calendar Year 7 2026	(I)	(J) Total Plan	(K) Reference
1	352.00	2.40%	$ -	$ -	$ -	$ 2,300,385	$ 2,844,940	$ -	$ 2,632,615		$ 7,777,940	Sum of Same Lines on p. 1 & p. 2
2	353.00	2.53%	$ 16,542,692	$ 19,582,382	$ 23,096,878	$ 22,073,157	$ 19,302,399	$ 18,615,703	$ 20,407,195		$ 139,620,406	Sum of Same Lines on p. 1 & p. 2
3	354.00	1.37%	$ 1,138,320	$ 1,111,147	$ 1,082,432	$ 850,792	$ -	$ -	$ -		$ 4,182,691	Sum of Same Lines on p. 1 & p. 2
4	356.00	1.20%	$ 4,765,917	$ 6,881,909	$ 9,502,181	$ 11,200,958	$ 11,497,320	$ 10,679,473	$ 7,601,921		$ 62,129,679	Sum of Same Lines on p. 1 & p. 2
5	362.00	1.61%	$ 7,026,754	$ 25,672,321	$ 38,188,063	$ 49,360,078	$ 24,862,469	$ 45,555,289	$ 32,554,913		$ 223,219,887	Sum of Same Lines on p. 1 & p. 2
6	364.00	2.06%	$ 39,069,911	$ 34,048,557	$ 47,918,689	$ 52,531,374	$ 44,678,960	$ 49,169,935	$ 46,385,522		$ 313,802,948	Sum of Same Lines on p. 1 & p. 2
7	365.00	2.35%	$ 28,815,380	$ 27,771,432	$ 26,078,201	$ 27,620,140	$ 25,686,598	$ 27,204,806	$ 26,696,855		$ 189,873,412	Sum of Same Lines on p. 1 & p. 2
8	366.00	2.62%	$ 2,250,626	$ 2,346,110	$ 2,405,220	$ 2,690,012	$ 1,809,774	$ 2,715,591	$ 2,769,903		$ 16,987,236	Sum of Same Lines on p. 1 & p. 2
9	367.00	2.55%	$ 13,966,103	$ 13,407,560	$ 14,443,018	$ 14,226,294	$ 14,093,313	$ 14,938,612	$ 14,497,783		$ 99,572,683	Sum of Same Lines on p. 1 & p. 2
10	368.00	0.65%	$ 12,521,414	$ 12,200,598	$ 15,845,026	$ 17,725,277	$ 15,147,875	$ 16,296,875	$ 15,682,084		$ 105,419,149	Sum of Same Lines on p. 1 & p. 2
11	370.01	19.35%	$ 10,735,674	$ 10,950,388	$ 11,169,395	$ 11,392,783	$ 11,620,639	$ -	$ -		$ 55,868,879	Sum of Same Lines on p. 1 & p. 2
12	Total CapEx Additions		$ 136,832,791	$ 153,972,404	$ 189,729,103	$ 211,971,250	$ 171,544,287	$ 185,176,284	$ 169,228,791		$ 1,218,454,910	

Line	Total TDSIC Assets CapEx Additions (incl AFUDC): FERC Account	Depr Rate	Plan Year TDSIC 1 Thru 3/31/20	Plan Year TDSIC 3 4/1/20-3/31/21	Plan Year TDSIC 5 4/1/21-3/31/22	Plan Year TDSIC 7 4/1/22-3/31/23	Plan Year TDSIC 9 4/1/23-3/31/24	Plan Year TDSIC 11 4/1/24-3/31/25	Plan Year TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Total Plan	Reference
13	352.00	2.40%	$ -	$ -	$ -	$ -	$ 2,300,385	$ 2,844,940	$ -	$ 2,632,615	$ 7,777,940	Sum of Same Lines on p. 1 & p. 2
14	353.00	2.53%	$ -	$ 16,542,692	$ 19,582,382	$ 23,096,878	$ 22,073,157	$ 19,302,399	$ 18,615,703	$ 20,407,195	$ 139,620,406	Sum of Same Lines on p. 1 & p. 2
15	354.00	1.37%	$ -	$ 1,138,320	$ 1,111,147	$ 1,082,432	$ 850,792	$ -	$ -	$ -	$ 4,182,691	Sum of Same Lines on p. 1 & p. 2
16	356.00	1.20%	$ -	$ 4,765,917	$ 6,881,909	$ 9,502,181	$ 11,200,958	$ 11,497,320	$ 10,679,473	$ 7,601,921	$ 62,129,679	Sum of Same Lines on p. 1 & p. 2
17	362.00	1.61%	$ -	$ 11,251,524	$ 27,502,588	$ 39,999,824	$ 44,450,455	$ 29,095,162	$ 43,032,278	$ 27,888,056	$ 223,219,887	Sum of Same Lines on p. 1 & p. 2
18	364.00	2.06%	$ 4,281,117	$ 37,235,492	$ 35,886,510	$ 48,027,574	$ 52,751,284	$ 44,786,565	$ 49,509,809	$ 41,324,597	$ 313,802,948	Sum of Same Lines on p. 1 & p. 2
19	365.00	2.35%	$ 12,312,934	$ 28,082,071	$ 26,461,278	$ 25,914,617	$ 28,391,801	$ 25,504,493	$ 27,674,067	$ 15,532,151	$ 189,873,412	Sum of Same Lines on p. 1 & p. 2
20	366.00	2.62%	$ 250,490	$ 2,234,596	$ 2,279,093	$ 2,422,942	$ 2,558,378	$ 1,980,163	$ 2,791,032	$ 2,470,542	$ 16,987,236	Sum of Same Lines on p. 1 & p. 2
21	367.00	2.55%	$ 428,901	$ 13,598,438	$ 13,175,258	$ 14,106,029	$ 14,881,648	$ 13,996,222	$ 15,152,199	$ 14,233,987	$ 99,572,683	Sum of Same Lines on p. 1 & p. 2
22	368.00	0.65%	$ 231,365	$ 12,233,709	$ 12,572,860	$ 15,962,723	$ 17,821,051	$ 15,098,668	$ 16,493,422	$ 15,005,351	$ 105,419,149	Sum of Same Lines on p. 1 & p. 2
23	370.01	19.35%	$ -	$ 10,603,114	$ 10,625,300	$ 10,998,762	$ 12,017,531	$ 8,715,479	$ -	$ 2,908,693	$ 55,868,879	Sum of Same Lines on p. 1 & p. 2
24	Total CapEx Additions Placed in Service		$ 17,504,807	$ 137,685,873	$ 156,078,325	$ 191,113,962	$ 209,297,441	$ 172,821,412	$ 183,947,984	$ 150,005,107	$ 1,218,454,910	
	CWIP Balance 3/31		$ 28,415,644	$ 32,380,181	$ 39,847,691	$ 44,308,377	$ 36,586,612	$ 38,265,691	$ 24,803,697	$ -		

Line	Total TDSIC Assets 3/31 Utility Plant Balance: FERC Account	Depr Rate	TDSIC 1 3/31/2020	TDSIC 3 3/31/2021	TDSIC 5 3/31/2022	TDSIC 7 3/31/2023	TDSIC 9 3/31/2024	TDSIC 11 3/31/2025	TDSIC 13 3/31/2026	TDSIC 14 3/31/2027	Reference
25	352.00	2.40%	$ -	$ -	$ -	$ -	$ 2,300,385	$ 5,145,325	$ 5,145,325	$ 7,777,940	Sum of Same Lines on p. 1 & p. 2
26	353.00	2.53%	$ -	$ 16,542,692	$ 36,125,074	$ 59,221,952	$ 81,295,109	$ 100,597,508	$ 119,213,211	$ 139,620,406	Sum of Same Lines on p. 1 & p. 2
27	354.00	1.37%	$ -	$ 1,138,320	$ 2,249,467	$ 3,331,899	$ 4,182,691	$ 4,182,691	$ 4,182,691	$ 4,182,691	Sum of Same Lines on p. 1 & p. 2
28	356.00	1.20%	$ -	$ 4,765,917	$ 11,647,826	$ 21,150,007	$ 32,350,965	$ 43,848,285	$ 54,527,758	$ 62,129,679	Sum of Same Lines on p. 1 & p. 2
29	362.00	1.61%	$ -	$ 11,251,524	$ 38,754,112	$ 78,753,936	$ 123,204,391	$ 152,299,553	$ 195,331,831	$ 223,219,887	Sum of Same Lines on p. 1 & p. 2
30	364.00	2.06%	$ 4,281,117	$ 41,516,609	$ 77,403,119	$ 125,430,694	$ 178,181,977	$ 222,968,542	$ 272,478,351	$ 313,802,948	Sum of Same Lines on p. 1 & p. 2
31	365.00	2.35%	$ 12,312,934	$ 40,395,005	$ 66,856,283	$ 92,770,900	$ 121,162,701	$ 146,667,194	$ 174,341,261	$ 189,873,412	Sum of Same Lines on p. 1 & p. 2
32	366.00	2.62%	$ 250,490	$ 2,485,086	$ 4,764,178	$ 7,187,121	$ 9,745,499	$ 11,725,662	$ 14,516,694	$ 16,987,236	Sum of Same Lines on p. 1 & p. 2
33	367.00	2.55%	$ 428,901	$ 14,027,340	$ 27,202,598	$ 41,308,626	$ 56,190,274	$ 70,186,497	$ 85,338,696	$ 99,572,683	Sum of Same Lines on p. 1 & p. 2
34	368.00	0.65%	$ 231,365	$ 12,465,074	$ 25,037,934	$ 41,000,657	$ 58,821,708	$ 73,920,376	$ 90,413,798	$ 105,419,149	Sum of Same Lines on p. 1 & p. 2
35	370.01	19.35%	$ -	$ 10,603,114	$ 21,228,414	$ 32,227,176	$ 44,244,707	$ 52,960,186	$ 52,960,186	$ 55,868,879	Sum of Same Lines on p. 1 & p. 2
36	Total End of Year Utility Plant Balance		$ 17,504,807	$ 155,190,680	$ 311,269,005	$ 502,382,967	$ 711,680,408	$ 884,501,819	$ 1,068,449,803	$ 1,218,454,910	

Line	Total TDSIC Assets Depreciation Expense: FERC Account	Depr Rate	TDSIC 1 Thru 3/31/20	TDSIC 3 4/1/20-3/31/21	TDSIC 5 4/1/21-3/31/22	TDSIC 7 4/1/22-3/31/23	TDSIC 9 4/1/23-3/31/24	TDSIC 11 4/1/24-3/31/25	TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Reference
37	352.00	2.40%	$ -	$ -	$ -	$ -	$ 27,605	$ 89,349	$ 123,488	$ 155,079	Sum of Same Lines on p. 1 & p. 2
38	353.00	2.53%	$ -	$ 209,265	$ 666,247	$ 1,206,140	$ 1,777,541	$ 2,300,942	$ 2,780,606	$ 3,274,245	Sum of Same Lines on p. 1 & p. 2
39	354.00	1.37%	$ -	$ 7,797	$ 23,206	$ 38,232	$ 51,475	$ 57,303	$ 57,303	$ 57,303	Sum of Same Lines on p. 1 & p. 2
40	356.00	1.20%	$ -	$ 28,596	$ 98,482	$ 196,787	$ 321,006	$ 457,196	$ 590,256	$ 699,945	Sum of Same Lines on p. 1 & p. 2
41	362.00	1.61%	$ -	$ 90,575	$ 402,545	$ 945,940	$ 1,625,765	$ 2,217,807	$ 2,798,433	$ 3,369,341	Sum of Same Lines on p. 1 & p. 2
42	364.00	2.06%	$ 44,096	$ 471,717	$ 1,224,873	$ 2,089,188	$ 3,127,211	$ 4,131,850	$ 5,103,103	$ 6,038,697	Sum of Same Lines on p. 1 & p. 2
43	365.00	2.35%	$ 144,677	$ 619,318	$ 1,260,203	$ 1,875,619	$ 2,513,720	$ 3,147,001	$ 3,771,849	$ 4,279,522	Sum of Same Lines on p. 1 & p. 2
44	366.00	2.62%	$ 3,281	$ 35,836	$ 94,965	$ 156,562	$ 221,817	$ 281,272	$ 343,775	$ 412,701	Sum of Same Lines on p. 1 & p. 2
45	367.00	2.55%	$ 5,468	$ 184,317	$ 525,682	$ 873,518	$ 1,243,111	$ 1,611,304	$ 1,982,946	$ 2,357,620	Sum of Same Lines on p. 1 & p. 2
46	368.00	0.65%	$ 752	$ 41,263	$ 121,885	$ 214,625	$ 324,423	$ 431,412	$ 534,086	$ 636,457	Sum of Same Lines on p. 1 & p. 2
47	370.01	19.35%	$ -	$ 1,025,851	$ 3,079,700	$ 5,171,828	$ 7,398,655	$ 9,404,573	$ 10,247,796	$ 10,529,212	Sum of Same Lines on p. 1 & p. 2
48	Total Depr Exp - Annualized		$ 198,274	$ 2,714,535	$ 7,497,789	$ 12,768,441	$ 18,632,327	$ 24,130,008	$ 28,333,641	$ 31,810,124	

Line	Total TDSIC Assets 3/31 Accumulated Depreciation: FERC Account	Depr Rate	TDSIC 1 3/31/2020	TDSIC 3 3/31/2021	TDSIC 5 3/31/2022	TDSIC 7 3/31/2023	TDSIC 9 3/31/2024	TDSIC 11 3/31/2025	TDSIC 13 3/31/2026	TDSIC 14 3/31/2027	Reference
49	352.00	2.40%	$ -	$ -	$ -	$ -	$ (27,605)	$ (116,953)	$ (240,441)	$ (395,520)	Sum of Same Lines on p. 1 & p. 2
50	353.00	2.53%	$ -	$ (209,265)	$ (875,512)	$ (2,081,652)	$ (3,859,193)	$ (6,160,135)	$ (8,940,740)	$ (12,214,985)	Sum of Same Lines on p. 1 & p. 2
51	354.00	1.37%	$ -	$ (7,797)	$ (31,004)	$ (69,236)	$ (120,711)	$ (178,014)	$ (235,317)	$ (292,620)	Sum of Same Lines on p. 1 & p. 2
52	356.00	1.20%	$ -	$ (28,596)	$ (127,078)	$ (323,865)	$ (644,871)	$ (1,102,066)	$ (1,692,323)	$ (2,392,267)	Sum of Same Lines on p. 1 & p. 2
53	362.00	1.61%	$ -	$ (90,575)	$ (493,120)	$ (1,439,060)	$ (3,064,824)	$ (5,282,631)	$ (8,081,064)	$ (11,450,405)	Sum of Same Lines on p. 1 & p. 2
54	364.00	2.06%	$ (44,096)	$ (515,812)	$ (1,740,685)	$ (3,829,874)	$ (6,957,084)	$ (11,088,934)	$ (16,192,037)	$ (22,230,735)	Sum of Same Lines on p. 1 & p. 2
55	365.00	2.35%	$ (144,677)	$ (763,995)	$ (2,024,198)	$ (3,899,817)	$ (6,413,537)	$ (9,560,538)	$ (13,332,388)	$ (17,611,910)	Sum of Same Lines on p. 1 & p. 2
56	366.00	2.62%	$ (3,281)	$ (39,117)	$ (134,083)	$ (290,645)	$ (512,462)	$ (793,734)	$ (1,137,509)	$ (1,550,211)	Sum of Same Lines on p. 1 & p. 2
57	367.00	2.55%	$ (5,468)	$ (189,786)	$ (715,467)	$ (1,588,985)	$ (2,832,096)	$ (4,443,400)	$ (6,426,346)	$ (8,783,966)	Sum of Same Lines on p. 1 & p. 2
58	368.00	0.65%	$ (752)	$ (42,015)	$ (163,900)	$ (378,526)	$ (702,948)	$ (1,134,360)	$ (1,668,446)	$ (2,304,903)	Sum of Same Lines on p. 1 & p. 2
59	370.01	19.35%	$ -	$ (1,025,851)	$ (4,105,552)	$ (9,277,380)	$ (16,676,035)	$ (26,080,608)	$ (36,328,404)	$ (46,857,616)	Sum of Same Lines on p. 1 & p. 2
60	Total 3/31 Accum Depr		$ (198,274)	$ (2,912,810)	$ (10,410,599)	$ (23,179,040)	$ (41,811,366)	$ (65,941,375)	$ (94,275,015)	$ (126,085,139)	

Line	Total TDSIC Assets										Reference
61	3/31 Rate Base			$ 184,658,051	$ 340,706,097	$ 523,512,304	$ 706,455,653	$ 856,826,136	$ 998,978,485	$ 1,092,369,771	Sum of Same Lines on p. 1 & p. 2

INDIANAPOLIS POWER & LIGHT COMPANY
TRANSMISSION DISTRIBUTION STORAGE SYSTEM IMPROVEMENT CHARGE (TDSIC)
Property Tax Expense Estimate Calculation

Line	Description	(A)	(B) Year 2 2021	(C) Year 3 2022	(D) Year 4 2023	(E) Year 5 2024	(F) Year 6 2025	(G) Year 7 2026	(H)	(I) Reference
	Assessment Date	12/31/19	12/31/20	12/31/21	12/31/22	12/31/23	12/31/24	12/31/25		
	Transmission Assets									
	Property Tax Calculation - One Year in Arrears:									
1	Accumulated Additions		$ 22,446,929	$ 50,022,367	$ 83,703,858	$ 120,129,150	$ 153,773,809	$ 183,068,985		TDSIC Plan Filing Attachment CAR-3
2	less Accumulated Tax Depreciation		$ 953,591	$ 3,929,938	$ 9,263,661	$ 17,125,014	$ 27,296,330	$ 39,309,822		TDSIC Plan Filing Attachment CAR-3
3	Accumulated Additions Net of Tax Depr		$ 21,493,338	$ 46,092,429	$ 74,440,197	$ 103,004,136	$ 126,477,479	$ 143,759,163		Line 1 - Line 2
4	Current Year Additions		$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176		TDSIC Plan Filing Attachment CAR-3
5	less Tax Depreciation on CY Spend		$ 953,591	$ 1,151,833	$ 1,461,825	$ 1,526,714	$ 1,463,581	$ 1,259,657		TDSIC Plan Filing Attachment CAR-3
6	Current Year Additions Net of Tax Depr		$ 21,493,338	$ 26,423,605	$ 32,219,666	$ 34,898,578	$ 32,181,078	$ 28,035,519		Line 4 - Line 5
7	Credit Amount		60.0%	60.0%	60.0%	60.0%	60.0%	60.0%		
8	60% Credit for Gross Additions		$ 12,896,003	$ 15,854,163	$ 19,331,799	$ 20,939,147	$ 19,308,647	$ 16,821,311		Line 6 x Line 7
9	Net Assessed Value		$ 8,597,335	$ 30,238,267	$ 55,108,397	$ 82,064,990	$ 107,168,832	$ 126,937,851		Line 3 - Line 8
10	Property Tax Rate		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%		Property Tax Rate
11	Property Tax Expense - Annualized		$ 257,920	$ 907,148	$ 1,653,252	$ 2,461,950	$ 3,215,065	$ 3,808,136		Line 9 x Line 10
		TDSIC 1 11/1/20-10/31/21	TDSIC 3 11/1/21-10/31/22	TDSIC 5 11/1/22-10/31/23	TDSIC 7 11/1/23-10/31/24	TDSIC 9 11/1/24-10/31/25	TDSIC 11 11/1/25-10/31/26	TDSIC 13 11/1/26-10/31/27	TDSIC 14 11/1/27-10/31/28	
12		$ -	$ 257,920	$ 907,148	$ 1,653,252	$ 2,461,950	$ 3,215,065	$ 3,808,136	$ 3,808,136	Calendar Year
Line	Description		Year 2 2021	Year 3 2022	Year 4 2023	Year 5 2024	Year 6 2025	Year 7 2026		Reference
	Assessment Date	12/31/19	12/31/20	12/31/21	12/31/22	12/31/23	12/31/24	12/31/25		
	Distribution Assets									
	Property Tax Calculation - One Year in Arrears:									
13	Accumulated Additions		$ 114,385,862	$ 240,782,828	$ 396,830,440	$ 572,376,398	$ 710,276,026	$ 866,157,134		TDSIC Plan Filing Attachment CAR-3
14	less Accumulated Tax Depreciation		$ 5,709,531	$ 22,526,290	$ 50,613,292	$ 90,568,943	$ 140,535,209	$ 197,829,920		TDSIC Plan Filing Attachment CAR-3
15	Accumulated Additions Net of Tax Depr		$ 108,676,331	$ 218,256,539	$ 346,217,149	$ 481,807,456	$ 569,740,817	$ 668,327,214		Line 13 - Line 14
16	Current Year Additions		$ 114,385,862	$ 126,396,966	$ 156,047,612	$ 175,545,958	$ 137,899,628	$ 155,881,108		TDSIC Plan Filing Attachment CAR-3
17	less Tax Depreciation on CY Spend		$ 5,709,531	$ 6,178,592	$ 7,321,232	$ 8,083,486	$ 6,707,523	$ 6,157,963		TDSIC Plan Filing Attachment CAR-3
18	Current Year Additions Net of Tax Depr		$ 108,676,331	$ 120,218,374	$ 148,726,380	$ 167,462,472	$ 131,192,105	$ 149,723,145		Line 16 - Line 17
19	Credit Amount		60.0%	60.0%	60.0%	60.0%	60.0%	60.0%		
20	60% Credit for Gross Additions		$ 65,205,799	$ 72,131,024	$ 89,235,828	$ 100,477,483	$ 78,715,263	$ 89,833,887		Line 18 x Line 19
21	Net Assessed Value		$ 43,470,532	$ 146,125,514	$ 256,981,320	$ 381,329,972	$ 491,025,554	$ 578,493,327		Line 15 - Line 20
22	Property Tax Rate		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%		Property Tax Rate
23	Property Tax Expense - Annualized		$ 1,304,116	$ 4,383,765	$ 7,709,440	$ 11,439,899	$ 14,730,767	$ 17,354,800		Line 21 x Line 22
		TDSIC 1 11/1/20-10/31/21	TDSIC 3 11/1/21-10/31/22	TDSIC 5 11/1/22-10/31/23	TDSIC 7 11/1/23-10/31/24	TDSIC 9 11/1/24-10/31/25	TDSIC 11 11/1/25-10/31/26	TDSIC 13 11/1/26-10/31/27	TDSIC 14 11/1/27-10/31/28	
24		$ 102,502	$ 1,406,618	$ 4,486,267	$ 7,811,942	$ 11,542,401	$ 14,833,269	$ 17,457,302	$ 17,457,302	Calendar Year + TDSIC 1 Amount
Line	Description		Year 2 2021	Year 3 2022	Year 4 2023	Year 5 2024	Year 6 2025	Year 7 2026		Reference
	Total TDSIC Assets									
	Property Tax Calculation - One Year in Arrears:									
25	Accumulated Additions		$ 136,832,791	$ 290,805,195	$ 480,534,298	$ 692,505,548	$ 864,049,835	$ 1,049,226,119		TDSIC Plan Filing Attachment CAR-3
26	less Accumulated Tax Depreciation		$ 6,663,122	$ 26,456,227	$ 59,876,953	$ 107,693,956	$ 167,831,539	$ 237,139,742		TDSIC Plan Filing Attachment CAR-3
27	Accumulated Additions Net of Tax Depr		$ 130,169,669	$ 264,348,968	$ 420,657,345	$ 584,811,592	$ 696,218,296	$ 812,086,377		Line 25 - Line 26
28	Current Year Additions		$ 136,832,791	$ 153,972,404	$ 189,729,103	$ 211,971,250	$ 171,544,287	$ 185,176,284		TDSIC Plan Filing Attachment CAR-3
29	less Tax Depreciation on CY Spend		$ 6,663,122	$ 7,330,426	$ 8,783,057	$ 9,610,200	$ 8,171,104	$ 7,417,620		TDSIC Plan Filing Attachment CAR-3
30	Current Year Additions Net of Tax Depr		$ 130,169,669	$ 146,641,979	$ 180,946,046	$ 202,361,050	$ 163,373,183	$ 177,758,664		Line 28 - Line 29
31	Credit Amount		60.0%	60.0%	60.0%	60.0%	60.0%	60.0%		
32	60% Credit for Gross Additions		$ 78,101,802	$ 87,985,187	$ 108,567,628	$ 121,416,630	$ 98,023,910	$ 106,655,198		Line 30 x Line 31
33	Net Assessed Value		$ 52,067,868	$ 176,363,781	$ 312,089,718	$ 463,394,962	$ 598,194,386	$ 705,431,179		Line 27 - Line 32
34	Property Tax Rate		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%		Property Tax Rate
35	Property Tax Expense - Annualized		$ 1,562,036	$ 5,290,913	$ 9,362,692	$ 13,901,849	$ 17,945,832	$ 21,162,935		Line 33 x Line 34
		TDSIC 1 11/1/20-10/31/21	TDSIC 3 11/1/21-10/31/22	TDSIC 5 11/1/22-10/31/23	TDSIC 7 11/1/23-10/31/24	TDSIC 9 11/1/24-10/31/25	TDSIC 11 11/1/25-10/31/26	TDSIC 13 11/1/26-10/31/27	TDSIC 14 11/1/27-10/31/28	
36		$ 102,502	$ 1,664,538	$ 5,393,415	$ 9,465,194	$ 14,004,351	$ 18,048,334	$ 21,265,437	$ 21,265,437	Line 12 + Line 24

INDIANAPOLIS POWER & LIGHT COMPANY
TRANSMISSION DISTRIBUTION STORAGE SYSTEM IMPROVEMENT CHARGE (TDSIC)
TDSIC Retirements Depreciation Expense Estimate Calculation

Line	TDSIC Plan Projected Retirements FERC Account	(A) Depr Rate	(B) Calendar Year 1 2020	(C) Calendar Year 2 2021	(D) Calendar Year 3 2022	(E) Calendar Year 4 2023	(F) Calendar Year 5 2024	(G) Calendar Year 6 2025	(H) Calendar Year 7 2026	(I)	(J) Total Plan	(K) Reference
1	352.00	2.40%	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	IPL Fixed Assets Accounting Estimate
2	353.00	2.53%	$ 1,231,941	$ 3,954,309	$ 1,644,555	$ 341,603	$ 916,047	$ 620,044	$ 1,048,727		$ 9,757,226	IPL Fixed Assets Accounting Estimate
3	354.00	1.37%	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	IPL Fixed Assets Accounting Estimate
4	356.00	1.20%	$ 51,662	$ 83,569	$ 52,677	$ 60,877	$ 61,263	$ 55,789	$ 38,933		$ 404,770	IPL Fixed Assets Accounting Estimate
5	362.00	1.61%	$ 1,146,021	$ 2,654,604	$ 1,409,638	$ 1,053,622	$ 1,320,470	$ 1,153,473	$ 537,942		$ 9,275,770	IPL Fixed Assets Accounting Estimate
6	364.00	2.06%	$ 7,415,217	$ 5,720,125	$ 7,560,967	$ 7,374,609	$ 7,114,649	$ 6,443,123	$ 5,789,027		$ 47,417,717	IPL Fixed Assets Accounting Estimate
7	365.00	2.35%	$ 1,125,231	$ 863,094	$ 1,305,598	$ 1,418,379	$ 1,168,250	$ 1,258,873	$ 1,134,708		$ 8,274,133	IPL Fixed Assets Accounting Estimate
8	366.00	2.62%	$ 57,632	$ 57,632	$ 57,632	$ 100,856	$ 86,448	$ 100,856	$ 100,856		$ 561,912	IPL Fixed Assets Accounting Estimate
9	367.00	2.55%	$ 6,232,198	$ 6,342,870	$ 6,389,583	$ 6,351,738	$ 6,310,125	$ 6,353,246	$ 6,351,297		$ 44,331,057	IPL Fixed Assets Accounting Estimate
10	368.00	0.65%	$ 1,584,238	$ 1,567,558	$ 2,097,123	$ 2,232,092	$ 1,932,754	$ 2,041,205	$ 1,892,610		$ 13,347,580	IPL Fixed Assets Accounting Estimate
11	370.00	3.90%	$ 3,899,910	$ 3,899,910	$ 3,899,910	$ 3,899,910	$ 3,899,910	$ -	$ -		$ 19,499,550	IPL Fixed Assets Accounting Estimate
12	Total Estimated Projected Retirments		$ 22,744,050	$ 25,143,671	$ 24,417,683	$ 22,833,686	$ 22,809,916	$ 18,026,609	$ 16,894,100		$ 152,869,715	

Line	TDSIC Plan Projected Retirments FERC Account	Depr Rate	TDSIC 1 Thru 3/31/20	TDSIC 3 4/1/20-3/31/21	TDSIC 5 4/1/21-3/31/22	TDSIC 7 4/1/22-3/31/23	TDSIC 9 4/1/23-3/31/24	TDSIC 11 4/1/24-3/31/25	TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Total Plan	Reference
13	352.00	2.40%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
14	353.00	2.53%	$ 13,461	$ 2,207,057	$ 3,376,870	$ 1,318,817	$ 485,214	$ 842,046	$ 727,215	$ 786,545	$ 9,757,226	
15	354.00	1.37%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
16	356.00	1.20%	$ -	$ 72,554	$ 75,846	$ 54,727	$ 60,974	$ 59,895	$ 51,575	$ 29,200	$ 404,770	
17	362.00	1.61%	$ -	$ 1,809,672	$ 2,343,363	$ 1,320,634	$ 1,120,334	$ 1,278,721	$ 999,590	$ 403,457	$ 9,275,770	TDSIC 1: 3/31/2020 Actual Balance,
18	364.00	2.06%	$ 225,925	$ 8,619,323	$ 6,180,336	$ 7,514,378	$ 7,309,619	$ 6,946,768	$ 6,279,599	$ 4,341,770	$ 47,417,717	Thereafter: 75% of Prior Calendar Year + 25% of Current
19	365.00	2.35%	$ 252,191	$ 1,088,813	$ 973,720	$ 1,333,793	$ 1,355,847	$ 1,190,906	$ 1,227,832	$ 851,031	$ 8,274,133	Calendar Year
20	366.00	2.62%	$ 2,184	$ 69,856	$ 57,632	$ 68,438	$ 97,254	$ 90,050	$ 100,856	$ 75,642	$ 561,912	
21	367.00	2.55%	$ 8,877	$ 7,809,039	$ 6,354,548	$ 6,380,122	$ 6,341,335	$ 6,320,905	$ 6,352,759	$ 4,763,473	$ 44,331,057	
22	368.00	0.65%	$ 387,462	$ 1,588,665	$ 1,699,949	$ 2,130,865	$ 2,157,258	$ 1,959,867	$ 2,004,056	$ 1,419,458	$ 13,347,580	
23	370.00	3.90%	$ -	$ 4,874,888	$ 3,899,910	$ 3,899,910	$ 3,899,910	$ 2,924,933	$ -	$ -	$ 19,499,550	
24	Total CapEx Additions Placed In Service		$ 890,101	$ 28,139,866	$ 24,962,174	$ 24,021,684	$ 22,827,744	$ 21,614,089	$ 17,743,482	$ 12,670,575	$ 152,869,715	

Line	Retired Assets 3/31 Cumulative Retired Plant Balance: FERC Account	Depr Rate	TDSIC 1 3/31/2020	TDSIC 3 3/31/2021	TDSIC 5 3/31/2022	TDSIC 7 3/31/2023	TDSIC 9 3/31/2024	TDSIC 11 3/31/2025	TDSIC 13 3/31/2026	TDSIC 14 3/31/2027	Reference
25	352.00	2.40%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Line 13 Accumulated
26	353.00	2.53%	$ 13,461	$ 2,220,518	$ 5,597,389	$ 6,916,205	$ 7,401,419	$ 8,243,466	$ 8,970,681	$ 9,757,226	Line 14 Accumulated
27	354.00	1.37%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Line 15 Accumulated
28	356.00	1.20%	$ -	$ 72,554	$ 148,400	$ 203,127	$ 264,101	$ 323,995	$ 375,570	$ 404,770	Line 16 Accumulated
29	362.00	1.61%	$ -	$ 1,809,672	$ 4,153,035	$ 5,473,669	$ 6,594,003	$ 7,872,724	$ 8,872,314	$ 9,275,770	Line 17 Accumulated
30	364.00	2.06%	$ 225,925	$ 8,845,248	$ 15,025,584	$ 22,539,961	$ 29,849,580	$ 36,796,348	$ 43,075,947	$ 47,417,717	Line 18 Accumulated
31	365.00	2.35%	$ 252,191	$ 1,341,005	$ 2,314,725	$ 3,648,518	$ 5,004,365	$ 6,195,270	$ 7,423,102	$ 8,274,133	Line 19 Accumulated
32	366.00	2.62%	$ 2,184	$ 72,040	$ 129,672	$ 198,110	$ 295,364	$ 385,414	$ 486,270	$ 561,912	Line 20 Accumulated
33	367.00	2.55%	$ 8,877	$ 7,817,916	$ 14,172,464	$ 20,552,586	$ 26,893,920	$ 33,214,826	$ 39,567,584	$ 44,331,057	Line 21 Accumulated
34	368.00	0.65%	$ 387,462	$ 1,976,128	$ 3,676,077	$ 5,806,942	$ 7,964,200	$ 9,924,066	$ 11,928,123	$ 13,347,580	Line 22 Accumulated
35	370.00	3.90%	$ -	$ 4,874,888	$ 8,774,798	$ 12,674,708	$ 16,574,618	$ 19,499,550	$ 19,499,550	$ 19,499,550	Line 23 Accumulated
36	Total 3/31 Utility Plant Balance		$ 890,101	$ 29,029,968	$ 53,992,142	$ 78,013,826	$ 100,841,569	$ 122,455,659	$ 140,199,140	$ 152,869,715	

Line	Retired Assets Depreciation Expense: FERC Account	Depr Rate	TDSIC 1 Thru 3/31/20	TDSIC 3 4/1/20-3/31/21	TDSIC 5 4/1/21-3/31/22	TDSIC 7 4/1/22-3/31/23	TDSIC 9 4/1/23-3/31/24	TDSIC 11 4/1/24-3/31/25	TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Reference
37	352.00	2.40%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	(Line 13 x Col A x 50%) + (Prior Line 25 x Col A)
38	353.00	2.53%		$ 28,260	$ 98,897	$ 158,297	$ 181,118	$ 197,908	$ 217,759	$ 236,908	(Line 14 x Col A x 50%) + (Prior Line 26 x Col A)
39	354.00	1.37%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	(Line 15 x Col A x 50%) + (Prior Line 27 x Col A)
40	356.00	1.20%		$ 435	$ 1,326	$ 2,109	$ 2,803	$ 3,529	$ 4,197	$ 4,682	(Line 16 x Col A x 50%) + (Prior Line 28 x Col A)
41	362.00	1.61%		$ 14,568	$ 48,000	$ 77,495	$ 97,145	$ 116,457	$ 134,798	$ 146,092	(Line 17 x Col A x 50%) + (Prior Line 29 x Col A)
42	364.00	2.06%		$ 93,433	$ 245,870	$ 386,925	$ 539,612	$ 686,453	$ 822,685	$ 932,085	(Line 18 x Col A x 50%) + (Prior Line 30 x Col A)
43	365.00	2.35%		$ 18,720	$ 42,955	$ 70,068	$ 101,671	$ 131,596	$ 160,016	$ 184,443	(Line 19 x Col A x 50%) + (Prior Line 31 x Col A)
44	366.00	2.62%		$ 972	$ 2,642	$ 4,294	$ 6,465	$ 8,918	$ 11,419	$ 13,731	(Line 20 x Col A x 50%) + (Prior Line 32 x Col A)
45	367.00	2.55%		$ 99,792	$ 280,377	$ 442,744	$ 604,943	$ 766,387	$ 927,976	$ 1,069,708	(Line 21 x Col A x 50%) + (Prior Line 33 x Col A)
46	368.00	0.65%		$ 7,682	$ 18,370	$ 30,820	$ 44,756	$ 58,137	$ 71,020	$ 82,146	(Line 22 x Col A x 50%) + (Prior Line 34 x Col A)
47	370.00	3.90%		$ 95,060	$ 266,169	$ 418,265	$ 570,362	$ 703,446	$ 760,482	$ 760,482	(Line 23 x Col A x 50%) + (Prior Line 35 x Col A)
48	Total Depr Exp - Annualized		$ 14,320	$ 358,922	$ 1,004,605	$ 1,591,018	$ 2,148,875	$ 2,672,830	$ 3,110,351	$ 3,430,277	
	Total Depr Exp - Annualized - Transmission		$ -	$ 28,695	$ 100,222	$ 160,406	$ 183,921	$ 201,436	$ 221,956	$ 241,590	Sum of Lines 37 - 40
	Total Depr Exp - Annualized - Distribution		$ 14,320	$ 330,227	$ 904,382	$ 1,430,612	$ 1,964,954	$ 2,471,394	$ 2,888,395	$ 3,188,687	Sum of Lines 41 - 47

REGULATORY MECHANISMS

ELECTRIC GROUP

Type of Adjustment Clause

	Holding Company	Elec. Fuel/ Purch. Pwr	Conserv. Program Expense	Decoupling Full	Decoupling Partial	Renew-ables Expense	Environ-mental Compliance	New Capital Gener-ation Capacity	New Capital Generic Infra-structure	Trans-mission Expense	Other	Future Test Year
1	Algonquin Pwr & Util	√	- -	- -	√	- -	√	- -	√	√	Taxes, franchise fees; Renewables mechanism available	P
2	ALLETE	√	√	- -	- -	√	√	- -	- -	√		C
3	Alliant Energy	√	√	- -	- -	√	√	√	√	√	Taxes, franchise fees	C
4	Ameren Corp.	√	√	- -	√	√	√	- -	√	√	Taxes, franchise fees, bad debts	O,P
5	American Elec Pwr	√	√	- -	√	√	√	√	√	√	Taxes, franchise fees, bad debts, vegetation management costs	C,O,P
6	AVANGRID, Inc.	D	√	√	- -	√	- -	D	- -	- -	Storm costs	C
7	Black Hills Corp.	√	√	- -	√	√	√	√	√	√		O
8	CenterPoint Energy	D	√	- -	- -	- -	- -	D	√	√	Franchise fees	- -
9	CMS Energy Corp.	√	√	- -	- -	√	- -	- -	- -	√		C
10	Consolidated Edison	D	- -	√	- -	√	- -	- -	- -	- -		C
11	Dominion Energy	√	√	- -	- -	√	√	√	- -	√	Taxes, franchise fees	- -
12	DTE Energy Co.	√	√	- -	- -	√	- -	- -	- -	√		C
13	Duke Energy Corp.	√	√	- -	√	√	√	√	√	√	Taxes, franchise fees, bad debts, storm costs	C,O,P
14	Edison International	√	- -	√	- -	- -	- -	- -	- -	- -		C
15	El Paso Electric Co.	√	√	- -	- -	- -	- -	√	- -	- -	Military base discounts	- -
16	Entergy Corp.	√	√	- -	√	- -	√	√	√	√	Taxes, franchise fees, storm costs	O,P
17	Exelon Corp.	D	√	√	√	√	√	D	√	√	Taxes, franchise fees, bad debts, nuclear decomm., societal benefits	O,P
18	IDACORP, Inc.	√	√	√	- -	- -	- -	- -	- -	- -		P
19	NextEra Energy, Inc.	√	√	- -	- -	- -	√	√	- -	- -	Taxes, franchise fees	C
20	NorthWestern Corp.	√	√	- -	- -	- -	- -	- -	- -	- -	Purchased power contracts	- -
21	OGE Energy Corp.	√	√	- -	√	√	√	- -	√	√	Taxes, franchise fees, storm costs, security/safety related costs	- -
22	Otter Tail Corp.	√	√	- -	- -	√	√	- -	- -	√		C
23	PG&E Corp.	√	- -	√	- -	- -	- -	- -	- -	- -		C
24	Pinnacle West Capital	√	√	- -	√	√	√	√	- -	√	Franchise fees	- -
25	Portland General Elec.	√	√	- -	√	√	- -	- -	- -	- -		C
26	PPL Corp.	√	√	- -	√	√	√	- -	√	√	Taxes, franchise fees, universal service program costs	O
27	Pub Sv Enterprise Grp.	D	√	- -	- -	√	√	D	√	- -	Taxes, franchise fees, societal benefits	P
28	Southern Company	√	√	- -	√	- -	√	√	- -	- -	Taxes, franchise fees, storm costs	C,O
29	Vectren Corp.	√	√	- -	√	- -	- -	- -	√	√		- -
30	WEC Energy Group	√	- -	- -	- -	- -	- -	- -	- -	- -	Taxes, franchise fees	C
31	Xcel Energy Inc.	√	√	√	- -	√	√	√	√	√	Taxes, franchise fees, university discounts	C

Sources:

IPL Witness AMM Attachment 3, pages 2-5, contain operating company data that are aggregated into the parent company data on this page.

Notes:

D - Delivery-only utility.

C - Fully-forecasted test years commonly used in the state listed for this operating company.

O - Fully-forecasted test years occasionally used in the state listed for this operating company.

P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.

REGULATORY MECHANISMS

ELECTRIC OPERATING COS.

Holding Company/ Operating Company	Type of Svc	State	Type of Adjustment Clause (a): Elec. Fuel/ Gas/ Purch. Pwr	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renew-ables Expense	Environ-mental Compliance	New Capital: Gener-ation Capacity	New Capital: Generic Infra-structure	Trans-mission Expense	Other	Future Test Year (b)
ALGONQUIN PWR. & UTIL.													
Empire District Electric	Elec.	MO	√	--	--	--	--	√	--	--	√	√	P
Liberty Utilities	Elec.	NH	D	--	--	√	--	--	--	√	--	--	--
ALLETE													
Minnesota Pwr	Elec.	MN	√	√	--	--	√	√	--	--	√	--	C
ALLIANT ENERGY													
Interstate P&L	Elec.	IA	√	√	--	--	√	√	--	--	√	√	--
Wisconsin P&L	Elec.	WI	√	--	--	--	--	--	LIR	LIR	--	√	C
AMEREN													
Ameren Illinois	Elec.	IL	D	√	--	--	√	√	D	--	√	√	O
Union Electric	Elec.	MO	√	√	--	√	--	√	--	√	√	√	P
AMERICAN ELEC PWR													
AEP Texas Central	Elec.	TX	D	√	--	--	--	--	D	√	√	--	--
AEP Texas North	Elec.	TX	D	√	--	--	--	--	D	√	√	--	--
Appalachian Pwr	Elec.	VA	√	√	--	--	√	--	√	--	√	√	--
Indiana Michigan Pwr	Elec.	IN	√	√	--	√	√	√	--	√	√	√	--
Kentucky Pwr	Elec.	KY	√	√	--	√	√	√	√	--	--	√	O
Kingsport Power Co.	Elec.	TN	√	--	--	--	--	--	--	--	--	--	C
Ohio Pwr	Elec.	OH	D	√	--	√	√	--	D	√	√	√	P
Public Svc Co. of OK	Elec.	OK	√	√	--	√	--	√	--	√	√	√	--
Southwestern Elec Pwr	Elec.	AR	√	√	--	√	--	√	√	--	--	√	P
Wheeling Pwr	Elec.	WV	√	√	--	--	√	--	--	√	--	√	--
AVANGRID													
Central Maine Pwr	Elec.	ME	D	--	√	--	--	--	D	--	--	√	C
NY State E&G	Elec.	NY	D	--	√	--	√	--	D	--	--	--	C
Rochester G&E	Elec.	NY	D	--	√	--	√	--	D	--	--	--	C
United Illuminating	Elec.	CT	D	√	√	--	--	--	D	--	√	--	C
BLACK HILLS CORP.													
BH Power	Elec.	SD	√	√	--	√	--	√	--	--	√	√	--
Cheyenne Light	Elec.	WY	√	√	--	√	√	--	--	--	--	√	O
BH Colorado Elec	Elec	CO	√	√	--	--	√	--	√	√	--	√	--

REGULATORY MECHANISMS

ELECTRIC OPERATING COS.

Holding Company/ Operating Company	Type of Svc	State	Type of Adjustment Clause (a): Elec. Fuel/ Gas/ Purch. Pwr	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renew-ables Expense	Environ-mental Compliance	New Capital: Gener-ation Capacity	New Capital: Generic Infra-structure	Trans-mission Expense	Other	Future Test Year (b)
CENTERPOINT ENERGY													
Houston Electric	Elec.	TX	D	√	--	--	--	--	D	√	√	√	--
CMS ENERGY													
Consumers Energy	Elec.	MI	√	√	--	--	√	--	--	--	√	--	C
CONSOLIDATED EDISON													
Con Ed of NY	Elec.	NY	D	--	√	--	√	--	D	--	--	--	C
Orange & Rockland	Elec.	NY	D	--	√	--	√	--	D	--	--	--	C
DOMINION RESOURCES													
Virginia Electric Power	Elec.	VA	√	√	--	--	√	√	√	--	√	√	--
DTE ENERGY													
DTE Electric	Elec.	MI	√	√	--	--	√	--	--	--	√	--	C
DUKE ENERGY													
Duke Energy Carolinas	Elec.	NC	√	√	--	--	√	√	--	--	--	--	--
Duke Energy Florida	Elec.	FL	√	√	--	--	--	√	√	--	--	√	C
Duke Energy Indiana	Elec.	IN	√	√	--	√	√	√	√	√	√	√	--
Duke Energy Kentucky	Elec.	KY	√	√	--	√	√	--	--	--	--	√	O
Duke Energy Ohio	Elec.	OH	D	√	--	√	√	--	--	√	√	√	P
Duke Energy Progress	Elec.	SC	√	--	--	--	--	√	--	--	--	--	--
EDISON INT'L													
Southern California Ed.	Elec.	CA	√	--	√	--	--	--	--	--	--	--	C
EL PASO ELECTRIC													
El Paso Electric	Elec.	TX	√	√	--	--	--	--	--	√	--	√	--
ENTERGY CORP.													
Entergy Arkansas Inc.	Elec.	AR	√	√	--	√	--	--	√	√	√	√	P
Entergy Louisiana LLC	Elec.	LA	√	√	--	√	--	√	√	--	√	√	O
Entergy Mississippi Inc.	Elec.	MS	√	√	--	√	--	√	--	--	√	√	O
Entergy New Orleans Inc.	Elec.	LA	√	√	--	√	--	√	√	--	√	√	O
Entergy Texas Inc.	Elec.	TX	√	√	--	--	--	--	--	√	√	√	--

REGULATORY MECHANISMS

ELECTRIC OPERATING COS.

Holding Company/ Operating Company	Type of Svc	State	Type of Adjustment Clause (a): Elec. Fuel/ Gas/ Purch. Pwr	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renew-ables Expense	Environ-mental Compliance	New Capital: Gener-ation Capacity	New Capital: Generic Infra-structure	Trans-mission Expense	Other	Future Test Year (b)
EXELON CORP.													
Baltimore G&E	Elec.	MD	D	√	√	--	--	--	D	√	--	√	P
Commonwealth Edison	Elec.	IL	D	√	--	--	√	√	D	√	√	√	O
PECO Energy	Elec.	PA	D	√	--	--	--	--	D	√	--	√	O
Atlantic City Electric	Elec.	NJ	D	√	--	--	√	√	D	--	--	√	P
Delmarva P&L	Elec.	MD	D	√	√	--	--	--	D	√	--	--	P
Potomac Electric Pwr	Elec.	DC	D	--	--	√	√	--	D	√	--	√	P
IDACORP													
Idaho Power	Elec.	ID	√	√	√	--	--	--	--	--	--	--	P
NEXTERA ENERGY, INC.													
Florida Power & Light	Elec.	FL	√	√	--	--	--	√	√	--	--	√	C
NORTHWESTERN CORP.													
NorthWestern Corp.	Elec.	MT	√	√	--	--	--	--	--	--	--	√	--
OGE ENERGY													
Oklahoma G&E	Elec.	OK	√	√	--	√	√	√	--	√	√	√	--
OTTER TAIL CORP.													
Otter Tail Power	Elec.	MN	√	√	--	--	√	√	--	--	√	--	C
PG&E CORP.													
Pacific G&E	Elec.	CA	√	--	√	--	--	--	--	--	--	--	C
PINNACLE WEST													
Arizona Public Service	Elec.	AZ	√	√	--	√	√	√	√	--	√	√	--
PORTLAND GEN. ELEC.													
Portland General Electric	Elec.	OR	√	√	--	√	√	--	--	--	--	--	C
PPL CORP.													
Kentucky Utilities	Elec.	KY	√	√	--	√	√	√	--	--	--	√	O
Louisville G&E	Elec.	KY	√	√	--	√	√	√	--	--	--	√	O
PPL Electric Utilities	Elec.	PA	D	√	--	--	--	--	D	√	√	√	O
PUB SV ENTERPRISE GRP													
Pub Service E&G	Elec.	NJ	D	√	--	--	√	√	D	√	--	√	P

REGULATORY MECHANISMS

ELECTRIC OPERATING COS.

Holding Company/ Operating Company	Type of Svc	State	Type of Adjustment Clause (a): Elec. Fuel/ Gas/ Purch. Pwr	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renew-ables Expense	Environ-mental Compliance	New Capital: Gener-ation Capacity	New Capital: Generic Infra-structure	Trans-mission Expense	Other	Future Test Year (b)
SOUTHERN CO.													
Alabama Power	Elec.	AL	√	--	--	--	--	√	√	--	--	√	C
Georgia Power	Elec.	GA	√	--	--	--	--	--	√	--	--	--	C
Gulf Power	Elec.	FL	√	√	--	--	--	√	√	--	--	√	C
Mississippi Power	Elec.	MS	√	√	--	√	--	√	--	--	--	√	O
VECTREN CORP.													
Southern Indiana G&E	Elec.	IN	√	√	--	√	--	--	--	√	√	√	--
WEC ENERGY GROUP													
Wisconsin Electric Pwr	Elec.	WI	√	--	--	--	--	--	--	--	--	√	C
Wisconsin Public Service	Elec.	WI	√	--	--	--	--	--	--	--	--	√	C
XCEL ENERGY													
Northern States Pwr	Elec.	MN	√	√	√	--	√	√	--	--	√	--	C
Northern States Pwr	Elec.	WI	√	--	--	--	--	--	--	--	--	√	C
Public Svc. Co. of Colorado	Elec.	CO	√	√	--	--	√	√	√	√	--	√	--
Southwestern Public Svc.	Elec.	TX	√	√	--	--	--	--	--	√	√	√	--

Sources:

(a) Regulatory Research Associates, Regulatory Focus, *"Adjustment Clauses-A State-by-State Overview,"* Sep. 12, 2017.

(b) Edison Electric Institute, *"Alternative Regulation for Emerging Utility Challenges: 2015 Update,"* Nov. 11, 2015.

Notes:

D - Delivery-only utility.

C - Fully-forecasted test years commonly used in the state listed for this operating company.

O - Fully-forecasted test years occasionally used in the state listed for this operating company.

P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.

LIR - Limited issue reopeners.

FILED
June 18, 2020
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY PURSUANT TO IND. CODE § 8-1-39-9 FOR: (1) APPROVAL OF AN ADJUSTMENT TO ITS ELECTRIC SERVICE RATES THROUGH ITS TRANSMISSION, DISTRIBUTION, AND STORAGE SYSTEM IMPROVEMENT CHARGE ("TDSIC") RATE SCHEDULE, STANDARD CONTRACT RIDER NO. 3; AND (2) AUTHORITY TO DEFER 20% OF THE APPROVED CAPITAL EXPENDITURES AND TDSIC COSTS FOR RECOVERY IN PETITIONER'S NEXT GENERAL RATE CASE.	)	**CAUSE NO. 45264 TDSIC 1**

VERIFIED PETITION AND REQUEST
<u>FOR ADMINISTRATIVE NOTICE</u>

Indianapolis Power & Light Company ("IPL", "Petitioner" or "Company") respectfully petitions the Indiana Utility Regulatory Commission ("Commission") for: (1) approval of an adjustment to its electric service rates through a Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Rate Schedule, Standard Contract Rider No. 3 ("TDSIC Rider"), to effectuate the timely recovery of 80% of capital expenditures and TDSIC costs in connection with Petitioner's eligible transmission, distribution, and storage system improvements; and (2) authority to defer, as a regulatory asset, the remaining 20% of eligible and approved capital expenditures and TDSIC costs, with carrying costs, for recovery in Petitioner's next general rate case. IPL also requests the Commission to take administrative notice as set forth below. In support of this Verified Petition, IPL states as follows:

IPL's Corporate Status and Operations

1. IPL is an Indiana corporation with its principal office and place of business at One Monument Circle, Indianapolis, Indiana 46204. IPL is engaged in rendering electric utility service in the State of Indiana.

2. IPL provides retail electric utility service to more than 500,000 retail customers located principally in and near the City of Indianapolis, Indiana, and in portions of the following Indiana counties: Boone, Hamilton, Hancock, Hendricks, Johnson, Marion, Morgan, Owen, Putnam and Shelby Counties. IPL owns and operates electric generating, transmission and distribution plant, property and equipment and related facilities, which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light and power. IPL has maintained and continues to maintain its properties in a reliable state of operating condition.

Petitioner's "Public Utility" Status

3. IPL is a "public utility" under Ind. Code § 8-1-2-1 and Ind. Code § 8-1-39-4 and an "energy utility" under Ind. Code § 8-1-2.5-2. IPL is subject to the jurisdiction of this Commission in the manner and to the extent provided by the Public Service Commission Act, as amended, and other pertinent laws of the State of Indiana.

Relief Requested

4. The Commission approved IPL's TDSIC Plan by Order dated March 4, 2020 in Cause No. 45264 ("45264 Order"). In accordance with Ind. Code § 8-1-39-10(b), the Commission authorized TDSIC treatment for the improvements described in the IPL TDSIC Plan. The Commission directed IPL to file its TDSIC Plan updates and TDSIC rate updates separately on an

annual basis, staggered six months from each other, as subdockets in this Cause under the Cause No 45264 TDSIC X, with its first tracker filed on or before July 1, 2020. This Petition seeks to establish the "TDSIC rate" and addresses costs incurred under IPL's TDSIC Plan through March 31, 2020. IPL will file a TDSIC Plan update in December.

5. In this TDSIC rate filing, Petitioner respectfully requests approval of TDSIC Rider factors to effectuate the timely recovery of 80% of approved capital expenditures and TDSIC costs. The TDSIC 1 factors, when approved, are planned to go into effect starting with the November 2020 billing cycle and remain in effect until different Rider factors are approved, which is expected to be a period of approximately 12 months because IPL will seek approval of new factors in its TDSIC 3 filing. IPL asks the Commission to specifically approve and authorize recovery of the actual costs that exceed the amount previously approved. IPL also requests authority to defer, as a regulatory asset, the remaining 20% of approved capital expenditures and TDSIC costs, for recovery as part of IPL's next general rate case. IPL requests approval to adjust Petitioner's authorized return for purposes of Ind. Code § 8-1-2-42(d)(3) to reflect the incremental earnings that will result from this TDSIC Rider filing upon Commission approval. The proposed TDSIC Rider is included with IPL Witness Coklow's testimony as Attachment NHC-12.

Applicable Law

6. Petitioner considers Ind. Code §§ 8-1-39-9 and 12 of the Public Service Commission Act, as amended, among others, to be applicable to this Petition.

7. This Petition uses the customer class revenue allocation factors based on firm load approved in IPL's most recent retail base rate case order.

8. This Petition is not filed within nine months after October 31, 2018, the date of the Commission's order in IPL's most recent basic rate order in Cause No. 45029.

9. In accordance with Ind. Code § 8-1-39-9(e), IPL will petition the Commission for review and approval of its electric basic rates and charges before the expiration of its TDSIC Plan.

10. In accordance with Ind. Code § 8-1-39-9(f), IPL has not filed a petition under Ind. Code § 8-1-39-9 within the last six (6) months.

11. In accordance with Ind. Code § 8-1-39-9(g), IPL has, in its case-in-chief, provided specific justification for, and requests specific Commission approval of, actual capital expenditures and TDSIC costs that exceed the amounts approved in the March 4, 2020 Order in Cause No. 45264.

12. In accordance with Ind. Code § 8-1-39-14(a), IPL's proposed TDSIC Rider factors will not result in an average aggregate increase in Petitioner's total retail revenue of more than two percent (2%) in a twelve (12) month period.

Request for Administrative Notice.

13. Pursuant to 170 IAC 1-1.1-21, IPL requests administrative notice to be taken of the 45264 Order and the IPL TDSIC Plan approved by this Order. This order is available on the Commission's electronic docket. IPL will file a copy of the 45264 Order once this request is granted.

14. IPL's TDSIC Plan is Petitioner's Exhibit 2 in the record in Cause No. 45264. A complete copy of the public version Plan is attached hereto as Exhibit A and the unredacted copy is being filed with the Commission under seal in accordance with the docket entry in Cause No. 45264 dated August 7, 2019 authorizing the protection of this confidential information from

public disclosure. This document reflects the comprehensive compilation of the plan and appendices IPL presented in Cause No. 45264. Appendix 8.7 to this exhibit set forth the cost estimates, year by year project detail (sortable list) and plan projects by FERC account. For efficiency, IPL proposes that going forward, IPL's TDSIC Rider filings include Appendix 8.7 only and that the inclusion of this appendix be found to satisfy Ind. Code § 8-1-39-9(a)(2).

Procedural and Other Matters

15. IPL is filing its case-in-chief contemporaneous with its Petition, including direct testimony, attachments and workpapers of the following witnesses:

- Chad A. Rogers – Regulatory Policy
- James (Jim) William Shields Jr. – TDSIC Project Management
- Natalie Herr Coklow – Regulatory Accounting

16. The books and records of Petitioner supporting such data and calculations are kept in accordance with the Uniform System of Accounts for Electric Utilities prescribed by this Commission and are available for inspection and review by the Utility Consumer Counselor and this Commission.

17. Pursuant to 170 IAC 1-1.1-15(b) of the Commission's Rules of Practice and Procedure, IPL requests the Commission promptly conduct a prehearing conference and preliminary hearing to establish a procedural schedule in this Cause in accordance with Ind. Code § 8-1-39-12. In accordance with 170 I.A.C. 1-1.1-15(e), IPL will seek to enter into a stipulation with the Indiana Office of Utility Consumer Counselor regarding a procedural schedule in lieu of a prehearing conference.

18. In accordance Ind. Code § 8-1-39-12, the report of the OUCC (and intervenors, if any), is due not more than sixty (60) days after the filing of this Petition (Monday, August 17, 2020). The Commission order on this petition is due not more than one hundred twenty (120) days after the filing of this Petition (Friday, October 16, 2020). As noted above, IPL proposes to place the TDSIC Rider factors into effect with the November 2020 billing cycle which commences October 29, 2020.

Petitioner's Authorized Representatives

19. The name and address of Petitioner's duly authorized representative to whom all correspondence and communication concerning this Petition should be sent, is as follows:

Teresa Morton Nyhart (No. 14044-49)
Jeffrey M. Peabody (No. 28000-53)
Barnes & Thornburg LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Nyhart Telephone: (317) 231-7716
Peabody Telephone: (317) 231-6465
Facsimile: (317) 231-7433
Nyhart Email: tnyhart@btlaw.com
Peabody Email: jpeabody@btlaw.com

WHEREFORE, Petitioner respectfully requests that the Indiana Utility Regulatory Commission promptly publish notice, make such investigation and hold hearings as are necessary or advisable and thereafter, make and enter an order in this Cause approving this Petition and:

(1) approving the capital expenditures and TDSIC costs, including specifically the actual costs that exceed the previously approved estimates;

(2) approving timely recovery through IPL's TDSIC Rider of 80% of the approved capital expenditures and TDSIC costs;

(3) authorizing IPL to defer, as a regulatory asset, the remaining 20% of capital expenditures and TDSIC costs for recovery in IPL's next general rate case;

(4) approving IPL's TDSIC Rider and proposed factors;

(5) approving IPL's request of an adjustment to its authorized net operating income to reflect the approved earnings for purposes of Ind. Code § 8-1-2-42(d)(3); and

(6) granting to IPL such additional and further relief as may be deemed necessary or appropriate.

INDIANAPOLIS POWER & LIGHT COMPANY

Justin G. Sufan
Director, Regulatory & RTO Policy

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Jeffrey M. Peabody (No. 28000-53)
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Nyhart Email: tnyhart@btlaw.com
Peabody Email: jpeabody@btlaw.com

ATTORNEYS FOR PETITIONER INDIANAPOLIS POWER & LIGHT COMPANY

VERIFICATION

I affirm under penalties of perjury that the representations contained in the foregoing are true and correct to the best of my knowledge, information and belief.

Dated this 18th day of June, 2020.

Justin G. Sufan

CERTIFICATE OF SERVICE

The undersigned hereby certifies that on June 18, 2020, two copies of the foregoing Verified Petition and attachment were served by hand delivery and/or electronic mail upon the Office of Utility Consumer Counselor, PNC Center, 115 W. Washington Street, Suite 1500 South, Indianapolis, Indiana 46204; infomgt@oucc.in.gov.

Jeffrey M. Peabody

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ATTORNEYS FOR PETITIONER
INDIANAPOLIS POWER & LIGHT COMPANY

DMS 17525772v1

FILED
JULY 24, 2019
INDIANA UTILITY
REGULATORY COMMISSION

Indianapolis Power & Light Company Transmission Distribution Storage System Improvement Charge (TDSIC) Plan

ipl®
an AES company

July 2019

Table of Contents

1 Introduction

1.1 Statutory Framework: Indiana Code Chapter 8-1-39

In 2013, the Indiana General Assembly passed Indiana Senate Enrolled Act 560 to address the issue of aging transmission and distribution infrastructure. This enactment was codified at Ind. Code § 8-1-39 (Transmission, Distribution, and Storage System Improvement Charges and Deferrals ("TDSIC") (referred to herein as the "TDSIC Statute"). The statute was amended in 2019.[1] The TDSIC Statute incentivizes the expeditious investment in and modernization of Indiana's energy delivery system infrastructure.

The TDSIC Statute contemplates two distinct types of proceedings.

First, Section 10 of the TDSIC Statute permits a public utility to petition the Indiana Utility Regulatory Commission ("IURC" or "Commission") for approval of the public utility's multi-year plan for eligible transmission, distribution, and storage improvements. Ind. Code § 8-1-39-10(a). This is referred to as the "TDSIC Plan" or "Plan." While the original statute provided for seven-year plans, the recent amendment provides for plans that are five to seven years.

As used in the statute, "eligible transmission, distribution, and storage system improvements" means new or replacement electric or gas transmission, distribution, or storage utility projects that: (1) a public utility undertakes for purposes of safety, reliability, system modernization, or economic development; (2) were not included in the public utility's rate base in its most recent general rate case; and (3) either were (A) described in the public utility's TDSIC Plan and approved by the Commission under section 10 of the statute and authorized for TDSIC treatment; (B) described in the public utility's update to the public utility's TDSIC Plan under section 9 of the TDSIC Statute and authorized for TDSIC treatment by the Commission; or (C) approved as a targeted economic development project under section 11 of the TDSIC Statute.

The 2019 amendment to the TDSIC Statute clarifies that the term "eligible transmission, distribution, and storage system improvements" includes: (1) projects that do not include specific locations or an exact number of inspections, repairs, or replacements, including inspection based projects such as pole or pipe inspection projects, and pole or pipe replacement projects; and (2) projects involving advanced technology investments to support the modernization of a transmission, distribution, or storage system, such as advanced metering infrastructure, information technology systems, or distributed energy resource management systems.

[1] See 2019 Indiana General Assembly, House Enrolled Act No. 1470.

The TDSIC Statute provides that after notice and hearing, and not more than 210 days after the petition is filed, the IURC shall issue an order that includes the following:

(1) A finding of the best estimate of the cost of the eligible improvements included in the plan;

(2) A determination whether public convenience and necessity require or will require the eligible improvements included in the plan; and

(3) A determination whether the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan.[2]

If the Commission determines that the public utility's TDSIC plan is reasonable, the Commission shall approve the plan and authorize TDSIC treatment (*i.e.,* the cost recovery provided in the statute) for the eligible transmission, distribution, and storage improvements included in the plan.[3] The 2019 amendments also expressly provide for the early termination of an existing TDSIC plan and for requests for approval of a new plan.[4]

The second type of proceeding is governed by Section 9 of the TDSIC Statute.[5] Section 9 allows the public utility to petition the Commission for periodic automatic adjustments of the utility's rates to timely recover eighty percent (80%) of approved TDSIC Plan capital expenditures and TDSIC costs.[6] The remaining twenty percent (20%) of the approved capital expenditures and TDSIC costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, is deferred for recovery as part of the utility's next general rate case, which the TDSIC Statute requires the utility to file before expiration of the plan.[7] Section 9 also requires the utility to update its TDSIC plan at least annually.[8] Finally, should actual TDSIC Plan capital expenditures and TDSIC costs exceed the Commission-approved estimates, the utility must provide specific justification and the Commission must specifically approve such costs before they may be recovered through customer rates.[9]

Consistent with the TDSIC Statute, IPL has developed a seven (7) year TDSIC Plan that is a comprehensive package of specific projects to improve and modernize the Company's energy delivery system, including the reliability thereof; safeguard public and employee safety; and support economic development.

[2] Ind. Code § 8-1-39-10(b).
[3] *Id.*
[4] See HEA 1470, Section 4 (adding subsection (d) to section 10 of the TDSIC Statute.
[5] Ind. Code § 8-1-39-9.
[6] "TDSIC costs" captures the following costs during and after construction: depreciation expenses; operations and maintenance expenses; extensions and replacements to the extent not provided for through depreciation, in the manner provided for in IC 8-1-1.5-3-8; property taxes; pretax returns. Ind. Code § 8-1-39-7.
[7] Ind. Code § 8-1-39-9(c), (e).
[8] See HEA 1470, Section 3 (amending section 9(b) of the TDSIC Statute).
[9] Ind. Code § 8-1-39-9(g). See HEA 1470, Section 3 (renaming subsection (f) to subsection (g)).

1.2 Executive Summary

Indianapolis Power & Light Company ("IPL") provides retail electric service to approximately 500,000 customers in Indianapolis and surrounding communities. IPL owns and operates an extensive system of transmission and distribution (T&D) substations, circuits and related assets, equipment and monitoring and control systems.

IPL's T&D assets are aging, growing obsolete, and require modernization. Many assets are beyond their expected service lives and will face increasing likelihood of failures if not replaced. When these assets fail, IPL makes emergency repairs and customers experience outages; safety hazards also arise. The continued integrity, reliability and resiliency of the T&D infrastructure is a driving force behind IPL's TDSIC Plan. The deployment of new infrastructure, including distribution automation capabilities, will drive operational and network efficiencies, improve reliability, better regulate voltage, and improve outage management functions. The infrastructure improvements will also accommodate new demands from IPL customers who are deploying more sophisticated distributed energy resources and seeking additional levels of service.

IPL's TDSIC Plan proposes seven years of defined investment, totaling $1.2 billion, to replace, rebuild, upgrade, redesign and modernize a wide range of IPL's aging T&D system assets in two thematic areas: *Age and Condition*, and *Deliverability*.

The *Age and Condition* (83.3% of the estimated Plan cost) category addresses the many risks posed by aging assets. The category includes the replacement and rebuilding of substations and overhead circuits, the rehabilitation and repair of underground residential circuits, and rebuilding portions of the central business district. The *Deliverability* (16.7% of the estimated Plan cost) category deploys new technologies for advanced distribution management, adds new substation equipment to meet growth-driven capacity requirements, and creates system and operating efficiencies through automation, control functions and other advanced infrastructure.

Both categories support IPL's ability to maintain and operate the grid in a safe, reliable and efficient manner. Many of the modernizing improvements are focused on giving IPL's operators and engineers more information and control over the grid for purposes of delivering a better, more efficient energy experience. Other Projects target improvement in overall levels of reliability and integrity. A hardened and resilient grid can better withstand the impact of weather and is easier to restore when outages inevitably occur.

IPL's TDSIC Plan aligns with the TDSIC Statute as the Projects are undertaken for the purpose of safety, reliability, system modernization, and support of economic development. The estimated cost of the improvements included in the IPL TDSIC Plan costs are justified by incremental benefits attributable to the Plan. More specifically, the seven Projects that lend themselves to monetization, when viewed as part of a total portfolio, will provide a net benefit (i.e.; total escalated nominal benefits less the total escalated nominal cost of the Plan) of $939 million to

IPL's customers over a 20-year period. There are also a host of qualitative benefits, introduced in Section 3 (TDSIC Benefits) and expanded upon in the Section 6 (TDSIC Project Narratives) that combined with these quantifiable benefits, clearly meets the intent of the TDSIC Statute. Furthermore, without these improvements IPL's T&D system will face increasing levels of risk, and an erosion in overall grid integrity and reliability, which will be difficult to correct.

1.3 IPL's Transmission & Distribution System Overview

IPL's service area measures approximately 528 square miles.[10] IPL, headquartered in Indianapolis, is subject to the regulatory authority of the IURC and the Federal Energy Regulatory Commission ("FERC"). Additionally, IPL participates in the electricity markets managed by the Midcontinent Independent System Operator ("MISO").

IPL serves its customers through an interconnected grid of T&D circuits and substations as a vertically integrated investor-owned utility. This grid is comprised of a diverse set of company owned and operated assets, which are aging and, in some cases, nearing obsolescence.

The IPL transmission system consists of approximately 458 circuit miles of lines at 345,000 volts ("345 kV"), 408 circuit miles of line at 138,000 volts ("138 kV") and associated substations. There is a 345 kV ring around Marion County with multiple lines that interconnect into the ring at four different locations. Inside of the 345 kV ring is a 138-kV ring/grid. These two rings are connected through 345 kV to 138 kV auto transformers at six locations. This allows power to flow from the 345 kV transmission system to the 138 kV system. IPL has generation connected to the 345 kV system at the Petersburg ("Pete") Generating Station and generation connected to the 138 kV system at Harding Street Station ("HSS"), Eagle Valley ("EV") Station, and the Georgetown Generating Station.

The IPL transmission system operates as part of a larger integrated network system, commonly referred to as the Eastern Interconnection. The IPL transmission system is directly connected to the transmission systems of Indiana Michigan Power Company ("AEP"), Vectren Corporation ("Vectren"), Hoosier Energy Rural Electric Cooperative, Inc. ("HE"), and the electric system jointly owned by Duke Energy Indiana ("Duke"), Indiana Municipal Power Agency and Wabash Valley Power Association, Inc.

Through the interconnections with these other utilities, power can flow into and out of the IPL transmission system. The IPL transmission system is connected at both the 345 kV and 138 kV level with the other utilities. At the Petersburg Generation Station there are 345 kV level interconnections with Duke and AEP and 138 kV level interconnections with Duke, Vectren, and

[10] See Appendix 8.1 of IPL's TDSIC Plan for map of IPL's service area.

HE. In the Indianapolis area, IPL's transmission system has two 345 kV level interconnections with Duke and AEP and 138 kV level interconnections with Duke.

The distribution system consists of 4,961 circuit miles of underground primary and secondary cables and 6,110 circuit miles of overhead primary and secondary wire. Underground street lighting facilities include 773 circuit miles of underground cable. Also included in the system are 138 substations. Depending on the voltage levels at the substation, some substations may be considered both a bulk power substation and a distribution substation. There are 73 bulk power substations and 117 distribution substations; 52 substations are considered both bulk power and distribution substations. IPL uses a Secondary Network System to serve the City of Indianapolis Central Business District, sometimes also referred to as the "Mile Square." A unique feature of the Secondary Network System is the loss of a single component, such as a primary feeder or a network transformer, typically will not result in any customer losing power.

2 IPL's TDSIC Plan

2.1 The Modernizing Opportunity

IPL has several core opportunities related to its T&D assets and systems.

- First, IPL's T&D aging infrastructure requires modernization. Many of these assets are beyond their expected service lives and will face increasing likelihood of failures if not replaced. When these assets fail, which can lead to power outages, IPL must make emergency repairs; safety hazards can also arise during these outages depending on their nature.
- Second, grid assets require modernization to accommodate new demands from IPL customers who are deploying more sophisticated distributed energy resources and seeking additional levels of service.
- Third, with the deployment of new grid technologies, IPL's capability to operate and maintain the grid in a reliable, cost-effective, safe and efficient manner will be enhanced.

IPL must address these modernization opportunities to continue to operate and maintain a safe and reliable grid. Absent action, the reliability and integrity of IPL's T&D infrastructure may decline, safety levels will erode, and customer satisfaction with IPL's service will suffer. Customers will experience more persistent and more frequent power outages.

2.2 The Solution: IPL's TDSIC Plan

To address these modernization opportunities, -- and mitigate the reliability and integrity risks attendant to them -- IPL is proposing a seven-year, $1.2 billion TDSIC Plan to rebuild, upgrade, replace and modernize a wide range of IPL's aging transmission and distribution system assets.

The seven-year TDSIC Plan is guided by the TDSIC Statute. IPL's TDSIC Plan is summarized in Table 2.1 below.

Table 2.1 – IPL's TDSIC Plan Projected Annual Capital Costs (in millions)

Project Type	2020	2021	2022	2023	2024	2025	2026	7-Year Total
Age & Condition Projects								
Circuit Rebuilds	$ 27.2	$ 25.3	$ 45.8	$ 52.8	$ 47.8	$ 49.9	$ 49.9	$ 298.7
Substation Assets Replacement	$ 16.7	$ 27.0	$ 39.9	$ 39.2	$ 34.5	$ 44.3	$ 46.5	$ 248.1
XLPE Cable Replacement	$ 12.2	$ 11.8	$ 12.5	$ 12.4	$ 12.3	$ 12.8	$ 12.3	$ 86.2
4 kV Conversion	$ 19.7	$ 13.8	$ 15.4	$ 15.5	$ 7.6	$ 12.4	$ 7.5	$ 92.0
Tap Reliability Improvement Projects	$ 10.9	$ 10.4	$ 10.6	$ 10.8	$ 11.0	$ 11.3	$ 11.5	$ 76.5
Meter Replacement	$ 10.7	$ 11.0	$ 11.2	$ 11.4	$ 11.6	$ -	$ -	$ 55.9
CBD Secondary Network Upgrades	$ 4.6	$ 5.9	$ 5.3	$ 5.9	$ 5.0	$ 5.9	$ 6.4	$ 39.0
Static Wire Performance Improvement	$ 4.8	$ 6.9	$ 9.5	$ 11.2	$ 11.5	$ 10.7	$ 7.6	$ 62.1
Remote End - Breaker Relay/Upgrades	$ 3.0	$ 2.0	$ 5.6	$ 1.6	$ 6.2	$ 3.1	$ 6.4	$ 28.0
Pole Replacements	$ 3.3	$ 3.3	$ 3.4	$ 3.5	$ 3.5	$ 3.6	$ 3.7	$ 24.2
Steel Tower Life Extension	$ 1.1	$ 1.1	$ 1.1	$ 0.9	$ -	$ -	$ -	$ 4.2
Age & Condition Projects Total	$ 114.2	$ 118.6	$ 160.3	$ 165.1	$ 151.0	$ 153.9	$ 151.8	$ 1,015.0
Deliverability Projects								
Distribution Automation	$ 18.8	$ 19.2	$ 13.6	$ 13.9	$ 14.2	$ 14.5	$ 14.8	$ 109.0
Substation Design Upgrades	$ 3.8	$ 16.2	$ 15.8	$ 32.9	$ 6.3	$ 16.8	$ 2.6	$ 94.5
Deliverability Projects Total	$ 22.6	$ 35.4	$ 29.5	$ 46.8	$ 20.5	$ 31.3	$ 17.4	$ 203.5
Total Capital Costs	**$ 136.8**	**$ 154.0**	**$ 189.7**	**$ 212.0**	**$ 171.5**	**$ 185.2**	**$ 169.2**	**$ 1,218.5**
Amount of Transmission	$ 22.4	$ 27.6	$ 33.7	$ 36.4	$ 33.6	$ 29.3	$ 30.6	$ 213.7
Amount of Distribution	$ 114.4	$ 126.4	$ 156.0	$ 175.5	$ 137.9	$ 155.9	$ 138.6	$ 1,004.7
Total Capital Costs	**$ 136.8**	**$ 154.0**	**$ 189.7**	**$ 212.0**	**$ 171.5**	**$ 185.2**	**$ 169.2**	**$ 1,218.5**

To assist in describing the Plan, IPL organized its TDSIC proposal within two thematic areas: *Age and Condition*, and *Deliverability*. *Age and Condition* covers the IPL TDSIC Plan Projects that address the many risks posed by aging assets. Amongst other items, these project categories are devoted to the replacement and rebuilding of substations and overhead circuits, the rehabilitation and repair of underground residential circuits, and to rebuilding portions of the central business district. *Age and Condition* covers approximately 83.3% of the Plan's estimated cost.

The *Deliverability* category forms the remaining Projects and comprises 16.7% of the Plan's estimated cost. This Project group brings new technologies to:

- deploy Distribution Automation control system,
- add new substation equipment to meet growth-driven capacity requirements, and
- create system and operating efficiencies through automation, control functions and other advanced infrastructure.

Projects in both plan categories -- *Age and Condition* and *Deliverability* -- support IPL's ability to maintain and operate the grid in a safe, reliable and efficient manner. Many of the modernizing improvements are focused on giving IPL's operators and engineers more information and control over the grid for purposes of delivering a better, more efficient energy experience. Other projects target improvement in overall levels of reliability and integrity. A hardened and resilient grid is one that can better withstand the impact of weather and is easier to restore when outages inevitably occur.

2.3 Asset Management

IPL has a well-established asset management framework, which was recently the subject of a stakeholder collaborative discussion conducted in accordance with the Commission order in Cause No. 44576. In assembling this TDSIC Plan, the asset management principles already in place were applied and relevant data, information and tools were used to develop investment projects. For example, IPL's compilation of asset condition data allows the 'effective age' of the assets to be estimated. The asset management work done to date provided a solid foundation to build from in the development of the TDSIC Plan.

2.4 TDSIC Plan Development

To develop the proposed TDSIC Plan, IPL conducted an iterative process to prioritize system needs and determine how to best address aging infrastructure while also building a modern grid that is ready and able to meet the demands of the future. IPL relied on subject matter experts who operate and maintain the IPL electric system.

IPL also engaged a third-party consultant, Burns & McDonnell Engineering Company, Inc. ("BMcD") to assess asset risk and prioritize investment. To provide further rigor to the analysis, IPL engaged Black & Veatch ("B&V") Corporation to review the Risk Model, validate the cost estimates, and otherwise assist in the development of the TDSIC Plan.

IPL considered feasibility in developing the scope and schedule of the proposed improvements. Feasibility has many underlying aspects, and includes considerations such as: (a) protecting public and worker safety, (b) recruiting and providing sufficient skilled labor, (c) contracting in such a way to provide for the on-time availability of needed equipment on reasonable commercial terms, (d) attending to back office capabilities (for such requirements as design work) in order to meet the demands of managing plan implementation, (e) securing necessary local permits, and (f) designing a schedule and pace for the work that minimizes customer power disruptions.

Section 6 provides further detail on each TDSIC Plan Project and associated benefits.

3 TDSIC Plan Benefits

3.1 Overview

The TDSIC Statute requires that the Commission order include a determination whether the estimated costs of the TDSIC Plan improvements are justified by incremental benefits attributable to the Plan. Consistent with this criterion, IPL has crafted a well-balanced and feasible Plan that reduces safety-related risks, improves reliability, advances system modernization, and supports economic development. Among several qualitative benefits, some of which can be quantified, there is a full array of anticipated benefits:

- Reduction of the average effective age of major assets and associated asset risk, decreasing the number and impact of faults occurring on the system.

- Improved safety by replacing aging and obsolete assets. IPL will be able to counter the effects of aging infrastructure by replacement, which in turn will maintain safety.

- Reduction of equipment failure caused outages, enabling IPL to sustain the system's reliability and integrity on a go-forward basis.

- Greater system resiliency, placing IPL in a better position to withstand system events with fewer impacts. Fewer customers will experience power outages and the time required to make repairs and restore service will be reduced.

- Modernization with the addition of new assets that meet modern design and engineering standards. The associated increase in modern diagnostic capabilities will improve the overall monitoring, outage response, and control functions, and lay the foundation for effective predictive maintenance of IPL's most critical assets.

- Modernization also provides a foundation for IPL to offer new energy services and integrate them with the utility grid.

- Self-healing (automatic restoration) and corresponding improved service restoration due to the installation of new distribution automation capabilities.

- Improved efficiencies of the distribution system that will result in better voltage regulation, higher degrees of power quality, and a reduction of energy consumption by IPL customers. In addition to supporting the growing demand for distributed resources, these efficiencies will translate into energy consumption savings.

- Enhanced customer experience through improved outage management and communication capabilities that will lead to a reduction in outage frequency and duration.

- Improved customer service through the acceleration of IPL's advanced smart metering initiative. This lays the foundation for customers to receive better and more meaningful information about their energy usage, enabling more informed choices, and they will benefit from quicker resolution of any billing inquiries and experience greater convenience in establishing or discontinuing service.

- Economic development in the communities to which IPL provides electric service.

In further reviewing this list of benefits (expanded upon in Section 6, "TDSIC Project Narratives", for each individual project), one can group the Plan benefits into one of the following seven categories:

1.) **Customer Experience** - a qualitative measure, defined in terms of information quality and availability, choices, and interconnection options.
2.) **Reliability and Resiliency** - the capability to meet the electric demands of customers while providing uninterrupted electric service, including momentary interruptions; and in the case of major outages and disturbances, withstand and quickly recover service.
3.) **Safety** – reducing the risk of harm to people and property posed by the potential physical hazards associated with IPL owned, operated and maintained T&D assets.
4.) **Operational Efficiency** - activities and investments that reduce or lessen upward pressure on IPL operating costs, improve worker productivity, lower the difficulty and/or complexity of IPL employee tasks, reduce future capital expenditures, and/or directly lower customer energy costs.
5.) **Risk Reduction** – consistent with the key elements of the ISO 31000 standard, activities and investments that will reduce the likelihood and/or consequence of an asset failure, thus improving reliability, reducing hazards, and reducing unplanned replacement of critical assets.

6.) **Power Quality** – reducing the number and magnitude of disturbances such as high or low voltage, voltage spikes and transients, flickers and voltage sags, surges and short-time over voltages, as well as harmonics and noise.

7.) **Modernization** – replacing and adding assets with modern equipment/material or adding new technology onto the system for improved performance, functionality and operational efficiency.

Table 3.1 below provides an overall view of the Plan's benefits. Viewed in this manner it is seen that the benefits of the Plan are spread across the full array of the benefit categories.

Table 3.1 – Mapping of Projects to Benefit Categories

	Project	Customer Experience	Reliability and Resiliency	Safety	Operational Efficiency	Risk Reduction	Power Quality	Modernization
	Age and Condition							
1	Circuit Rebuilds	X	X	X		X	X	
2	Substation Assets Replacement	X	X	X	X	X	X	X
3	XLPE Cable Replacement	X	X	X	X	X	X	X
4	4 kV Conversion		X	X	X	X	X	X
5	Tap Reliability Improvement Projects	X	X	X	X	X	X	
6	Meter Replacement	X		X	X		X	X
7	CBD Secondary Network Upgrades	X	X	X	X	X	X	X
8	Static Wire Performance Improvement	X	X	X	X	X	X	X
9	Remote End - Breakers Relay/Upgrades	X	X	X	X	X	X	X
10	Pole Replacements		X	X	X	X		
11	Steel Tower Life Extension		X	X	X	X		
	Deliverability							
12	Distribution Automation	X	X	X	X	X	X	X
13	Substation Design Upgrades	X	X	X	X	X	X	X

The following discussion expands further on the value of the Plan, by monetizing those aspects that lend themselves to such an approach yet adopts a conservative posture to avoid overstating these quantitative benefits. Though quantifying savings is important, IPL holds firm to the notion that the Plan provides benefits, both quantitative and qualitative, that far exceed these calculations.

IPL's monetization approach of the calculated benefits is discussed below, and the more qualitative or time-based (*e.g.,* AMI) benefits are further expounded upon in Section 6 of this Plan.

3.2 Monetization of the Benefits

3.2.1 Monetization Approach Overview

In developing a directionally accurate view of the monetized benefits of the Plan, IPL established the following criteria to drive its approach:

- Incorporate conservatism in projecting actual savings:
  - Adopted the averages of ranges for unitized costing (particularly relating to productivity improvements attributable to proactive versus reactive work, benefit capture planning horizon of 20 years, and costs attributable to a customer-experienced outage), and
  - Focused on the consequence areas in the Risk Model that can be more readily quantified (i.e., reactive vs proactive replacement and customer reliability).
- Apply the Risk Modeling framework and approaches used in developing the Plan:
  - Focused the monetization analysis on the five Projects for which the Risk Model calculated risk scores (i.e., Circuit Rebuilds, Substation Assets Replacement, XLPE Cable Replacement, 4 kV Conversion, and Remote End-Breaker/Relay Upgrades).
  - Applied a cost factor to account for the savings resulting from less reactive maintenance.
  - Applied the DOE Interruption Cost Estimate ("ICE") Calculator[11], used across the industry to estimate the interruption costs and/or benefits associated with reliability improvements to monetize risk costs. In keeping with our conservative approach, large C&I customers, though extremely significant in terms of impact on these risk costs, were not factored in this portion of the monetization effort.
- Where appropriate, maintain consistency in applying assumptions to the analytics used throughout the monetization analysis:
  - Deployed the DOE ICE Calculator to monetize projected customer savings relating to the Tap Reliability Improvement Projects and the self-healing aspect of Distribution Automation Project. IPL applied the same approaches and factors as those used for the five Projects for which the Risk Model calculated risk scores, except that for Distribution Automation where the full customer mix (i.e., residential, small C&I and large C&I), was considered.
  - Maintained a conservative posture in projecting savings attributable to the reduction in energy consumption related to the Distribution Automation Project.

[11] The DOE funded Interruption Cost Estimate ("DOE ICE Calculator") is an electric reliability planning tool developed by Freeman, Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The DOE ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy.

  - Established a 20-year planning horizon for the capture of benefits.
  - Used escalation and discount rates identical to those used in the IPL TDSIC Plan (2.0 percent and 6.6 percent respectively).
- Approach monetization from a portfolio perspective to avoid the double-counting of benefits attributable to the inherent inter-relationships among the 13 Projects. In so doing, IPL monetized the benefits for seven of the thirteen TDSIC Projects.

3.2.2 Self-Healing/Reliability Monetization

IPL monetized the self-healing aspect of the Distribution Automation and the Tap Reliability Improvement Projects, deploying the DOE ICE calculator:

- Distribution Automation

  The first benefit monetized under Distribution Automation Project was that associated with the Fault Location, Isolation, and Service Restoration (FLISR) functionality. This functionality is estimated to eliminate, on average, 23,000 customer interruptions per year, and reduce the duration of approximately 167,000 interruptions per year to less than 5 minutes. Using the DOE ICE Calculator, IPL calculated that its customers will realize about $21 million of value per year when the Project is completed, translating to an escalated nominal increased value of $428.8 million over the 20-year period. Key factors were considered in arriving at this figure:

  - In determining the requirement for 1,200 reclosers, IPL conducted a detailed reliability optimization analysis, defining the amount of sectionalizing that will yield the highest benefit to cost ratio in reliability. This analysis resulted in 400 customer sectionalizing sections for the FLISR portion of Distribution Automation.

  - In applying the DOE ICE Calculator to determine the financial benefits from the customer perspective, IPL accounted for the full customer experience (e.g., included Major Event Days and to properly account for momentary interruptions).

  - Applied IPL's customer mix (residential, small commercial and industrial and large commercial and industrial) and Indiana factors in calculating the savings (refer to Table 3.2).

Table 3.2 – Avoided Customer Interruptions Cost Factors by Customer Type

Customer Type	Unplanned Outage	Momentary Outage
Residential	$7.08	$4.81
Small C&I	$1,135.28	$493.81
Large C&I	$6,623.14	$3,364.44

- The actual realization of any savings was delayed until the beginning of the fourth year of the Plan, reflecting the anticipated installation of the Advanced Control System.

- Tap Reliability Improvement Projects

The primary purpose of this Project is to reduce the number of sustained outages on under-performing overhead fused taps. As a starting point, IPL reviewed historical outage information over a 3-year period and identified 306 taps as likely candidates for this Project. From that list, 20 were selected for the first year of the Project, understanding that a rolling 3-year history will be used to select future taps for reliability improvement. Based on the overhead and underground solutions chosen to improving performance on the 20 chosen fused taps, IPL predicts an overall year one reliability improvement of 75 percent (reflecting a split largely weighted towards underground taps where nearly a 100 percent improvement can be expected; less so for overhead in the range of 50 percent). As the Projects progresses to year seven, IPL assumes a steady decrease in the improvement opportunity, after which the projected "savings" will level off after year seven and stay constant through year 20.

For the purpose of monetization, IPL calculated Repair and Line Clearance savings as well as those related to Customer Reliability.

- Repair and Line Clearance: A per outage cost of $3,000 was calculated by determining the total amount of unplanned outage repair incurred in 2018 and dividing that number by the total number of unplanned outages. Line clearance savings were calculated based on current price per mile estimates for the portions that are converted to underground. Applying this factor resulted in total projected escalated nominal savings of $49.8 million over the 20-year period.

- Customer Reliability: This project eliminates sustained outages. IPL applied the DOE ICE Calculator, applying the same sustained outage factors as those used for the Distribution Automation Project. The resulting escalated nominal value over the 20-year period totaled $207.0 million.

3.2.3 Conservation Voltage Reduction Monetization

The second benefit monetized under the Distribution Automation Project were the benefits associated with Conservation Voltage Reduction. The monetization of these benefits focuses on the enablement of voltage control which is estimated to reduce customer energy consumption by one percent, saving 112,000 MWh per year. In first arriving at the 112,000 MWh saved per year, IPL adopted a conservative approach:

- Through actual testing, IPL calculated that a one percent decrease in voltage will result in a 0.65 percent reduction in consumption (referred to as the Conservation Voltage Reduction factor). Anticipating a reduction in this factor over time, IPL reduced it to 0.50 percent to calculate energy savings.
- Once deployed, the Distribution Automation Control System will decrease distribution system voltage by 2 percent on the 13.2 kV circuits where it is applied.
- Applying the Conservation Voltage Reduction Factor to the 2 percent reduction in voltage, IPL arrived at the one percent reduction in energy consumption or 112,000 MWh reduction annually.

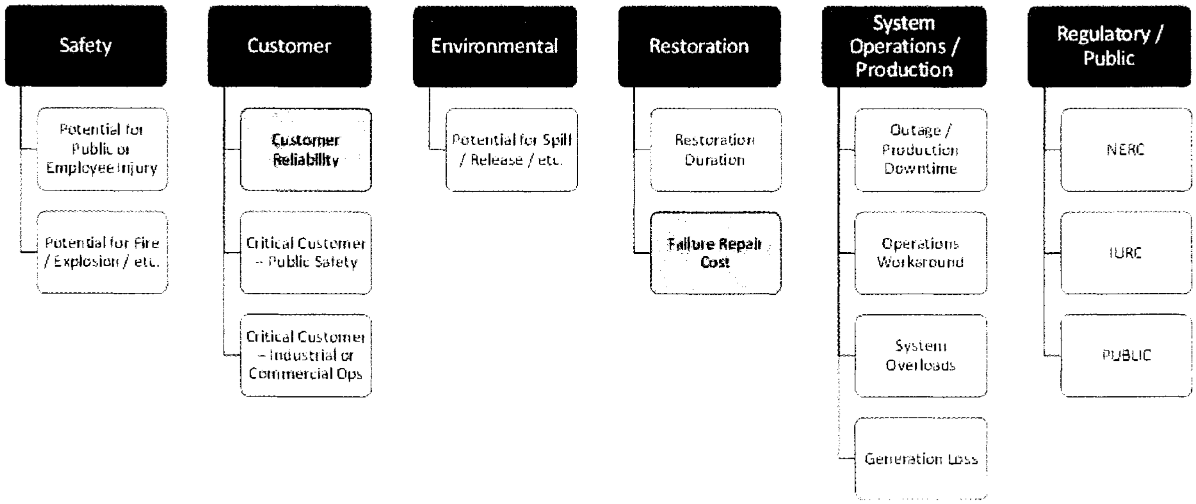
Further, the actual realization of any savings was delayed until the beginning of the fourth year of the Plan, accounting for the anticipated installation of the Advanced Control System and the integration of new and existing IT systems associated with the deployment of the Advanced Control System.

The projected escalated nominal savings of this aspect of the Distribution Automation Project over the 20-year period is $67.7 million.

3.2.4 Risk Reduction Monetization

Risk reduction monetization focused on the savings associated with reactive replacement of aged assets versus the proactive replacement of aged assets and the reliability improvements associated avoiding outages associated with assets that fail. The monetization of risk reduction only considered the five Projects for which the Risk Model calculated risk scores. And, as Figure 3.1 illustrates, the actual risk monetization was performed for a subset of the Consequence of Failure criteria.

Figure 3.1 – Consequence of Failure Criteria



NOTE: Shading reflects focus of the effort to monetize risk showing that only 2 of the 6 domains that define the Consequence of Failure (CoF) Criteria in the Risk Model were included in the monetized analysis. Further, of the 15 categories that define these domains, only two (less than 15 percent) were actually monetized.

- Reduction of Reactive Work: Focused on the difference between planned and reactive work, leveraging potential savings relating to reduced:
  - Overtime,
  - Premiums to make last minute purchase of equipment and materials,
  - Mobilization and rework related to making temporary fixes and returning to effect permanent repairs / replacements, and
  - Schedule disruption in reassigning crews, previously deployed on other work, on emergent activities.

  Applying a 40 percent factor to account for these premium costs (industry norms range between 30 and 50 percent with isolated examples of factors considerably higher), provides a projected escalated nominal benefit over the 20-year period of $532 million.

- Residential and Small C&I Reliability: Incorporated the DOE ICE Calculator, assuring alignment with the above stated factors used in monetizing the reliability portion of the Distribution Automation and Tap Reliability Improvement Projects; omitting the Large C&I customers and assuming full deployment of the Advanced Control System at the onset of the Plan. The resulting calculation provides a projected escalated nominal value over the 20-year period of $872 million. [12]

[12] See also Appendix 8.11 Risk Reduction Benefit Monetization Report.

3.3 Summary

The benefits and projected outcomes of the Plan considerably exceed its cost. Viewed as a portfolio of key capital investments:

- There are several qualitative benefits that do not lend themselves to monetization, but clearly bring value to our customers (*e.g.,* improved customer experience, power quality and modernization),
- There are additional benefits (*e.g.,* safety and environmental) that are hard to quantify and monetize (i.e., IPL opts to not place a specific dollar value on health and safety). In these instances, the quantification of benefits by the Plan is conservative by not assigning to them a dollar value, and
- There are areas where monetization analyses can be performed, while maintaining a conservative view towards projected savings / financial benefits to our customers. These are summarized in Table 3.3 below.

Table 3.3 – Summary of Monetized Benefits (20-Year Period)

Project	Category	Nominal Benefit ($M)
Distribution Automation	Self-Healing / Reliability	$429
	Conservative Voltage Reduction	$68
Tap Reliability Improvement Program	Repair / Line Clearance	$50
	Customer Reliability	$207
Asset Replacement Projects[1]	Reduction of Reactive Work	$532
	Customer and Small C&I Reliability	$872
	Total Monetized Benefit	**$2,158**
	TDSIC Plan Investment	($1,219)
	Net Monetized Benefit	**$939**

NOTE 1: The Asset Replacement Projects refer to an aggregation of the monetized benefits attributable to the Circuit Rebuilds, Substation Assets Replacement, XLPE Cable Replacement, 4 kV Conversion, and Remote End-Breaker/Relay Upgrades projects.

IPL notes that some specific projects presented in the Plan, viewed individually, will not produce monetized benefits equal to or greater than the proposed investment level (specifically, Substation Assets Replacement and Remote End – Breaker/Relay Upgrades Projects). This is reasonable due to the inherent redundancy built into substations for reliability purposes. Substation assets identified for replacement in the Plan are intended to maintain or enhance this existing inherent redundancy and the associated reliability levels they have historically produced. Thus, viewed as a total portfolio, the combined value (*i.e.,* benefit to our customers) of the Plan clearly meets the intent of the TDSIC Statute as it pertains to incremental benefits attributable to the Plan.

4 Best Estimates of Project Costs

4.1 Guidance Criteria: The AACE Cost Classification System

AACE International is an association that focuses on furthering approaches to total cost management and cost engineering. As a recognized leader in cost estimating, AACE has provided guidelines that are widely used in the utility industry to standardize approaches to project cost estimating. The Cost Estimate Classification System recommended by AACE International provides guidelines for applying the principles of cost estimating across the phases and stages of project cost estimates. This recognized cost classification system has been applied to other regulatory filings in Indiana.

AACE's Cost Estimate Classification System, presented in Table 4.1 below, maps the phases and stages of project cost estimating together with a generic maturity and quality matrix that can be applied across a wide variety of industries. This matrix describes a range of five estimate classes, with Class 1 estimates being the most detailed with the narrowest range of accuracy of -10% to +15% and at the furthest, Class 5 estimates which have less detail and an expected accuracy ranging from -50% to +100%.

Table 4.1 – AACE Cost Estimate Classification Matrix*

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

*Note: The above table has been re-produced in-part using data from "AACE International Recommended Practice No.18R-97: COST ESTIMATE CLASSIFICATION SYSTEM - AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES, Rev. March 1, 2016".

4.2 AACE - Class 2, Class 3 and Class 4 Distinctions

AACE defines the characteristics of each estimating class. The following is a summary of Class 2, Class 3 and Class 4 AACE Estimate Classification.

Class 2 estimates involve a high degree of deterministic estimating methods. Class 2 estimates are prepared in detail, and often involve numerous unit cost line items. Engineering is typically 30% to 75% complete. Class 2 estimates are used to prepare baseline schedules and budgets against which all actual costs and resources will be monitored for variations to the budget and form a part of the change management program.

Class 3 estimates involve a lesser degree of deterministic estimating methods than Class 2 estimates. Class 3 estimates form the basis for budget authorization and funding levels. Engineering is typically 10%-40% complete. Class 3 estimates rely on unit cost line items. This allows for factoring to obtain costs estimates.

Class 4 estimates are parametric in nature and are developed based on limited information. Parametric estimates rely on previous cost of similar projects or recent cost estimates. Class 4 estimates are used for preliminary budget approval. Engineering is typically 1%-15% complete.

4.3 Contingency, Indirect Costs and Inflation

Estimate accuracy range is an indication of the degree to which the final cost outcome for a given project will vary from the estimated cost. Accuracy is traditionally expressed as a +/- percentage range around the point estimate after application of contingency.

Contingency is applied to projects depending upon the technical complexity and the availability of appropriate cost reference information. The degree of project definition should also be considered in determining the appropriate contingency. As the degree of project definition increases, the expected accuracy of the estimate tends to improve, and the level of contingency required is reduced. For most projects in the IPL TDSIC Plan a 10% contingency was applied. For the Central Business District ("CBD") Secondary Network Upgrades Project, a 20% contingency was applied due to complexity of excavating in the downtown area. Likewise, the Distribution Automation control system component of the Distribution Automation Project also received a 20% contingency due to the complexity of deploying an Advanced Control System. The Meter Replacement Project received a 1% contingency due to the low complexity of the work, purchasing and replacing meters.

Both Allowance for Funds Used During Construction ("AFUDC") and Indirect Capital costs were applied to IPL's cost estimates. Both are variable costs that projects incur during construction. AFUDC charges were calculated using the current cost of capital and an estimation of project duration. Indirect Capital costs were estimated as a percentage of the project cost.

Lastly, project costs were escalated at the Consumer Price Index rate of 2% per year to account for inflation.

4.4 IPL's Cost Estimate Development Methodology

IPL developed cost estimates for projects included in the proposed 7-year TDSIC Plan. As shown in Table 4.2 below, AACE Class 2 estimates were developed for nine of the Projects for Year 1 and Year 2 of the Plan. Four of the Projects have Class 3 estimates for Year 1 and Year 2. For Tap Reliability Improvement Projects (TRIP's) Class 2 estimates were developed for the first year. Class 4 estimates were used for TRIP Project years 2 through 6 based on the method of defining the scope of these projects. Further explanation of TRIP's projects can be found in the TRIP project narrative in Section 6.5. For the remaining years of the Plan (Years 3-7), AACE Class 4 estimates were used due to limited scope definition and potential cost fluctuations.

Table 4.2 – Project Cost Estimate Classification by Year

	Plan Year						
Project	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Age & Condition							
Circuit Rebuilds	Class 2	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4
Substation Assets Replacement	Class 2	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4
XLPE Cable Replacement	Class 3	Class 3	Class 4	Class 4	Class 4	Class 4	Class 4
4 kV Conversion	Class 2	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4
Tap Reliability Improvement Projects	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4	Class 4
Meter Replacement	Class 2	Class 2	Class 4	Class 4	Class 4		
CBD Secondary Network Upgrades	Class 2	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4
Static Wire Performance Improvement	Class 2	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4
Remote End - Breaker Relay/Upgrades	Class 2	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4
Pole Replacements	Class 3	Class 3	Class 4	Class 4	Class 4	Class 4	Class 4
Steel Tower Life Extension	Class 3	Class 3	Class 4	Class 4			
Deliverability							
Distribution Automation	Class 3	Class 3	Class 4	Class 4	Class 4	Class 4	Class 4
Substation Design Upgrades	Class 2	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4

4.4.1 Class 2 Estimate Development

IPL employed the help of several engineering firms to complete the detailed engineering for Year 1 and Year 2 Projects. IPL created project scope statements for each project and worked closely with the engineering firms through the design process to ensure the design matched the scope. Class 2 estimates were developed by completing individual project detailed engineering. The total project costs were estimated by the engineering firm assigned to the project. IPL worked with B&V to create a uniform method of developing and presenting the Class 2 estimates. IPL subject matter experts in each discipline worked with the various engineering firms to ensure conformity to the uniform method of developing Class 2 estimates. There is no retirement or maintenance cost included in the Class 2 estimates.

For the CBD Secondary Network Upgrades, Static Wire Performance Improvement, Substation Assets Replacement, Remote Ends – Breaker/Relay Upgrades and Substation Design Upgrades Projects a construction labor bid event was held to determine the labor costs component of the project estimate for Plan Years 1 and 2. For overhead distribution projects and portions of the CBD Secondary Network Upgrades Project, existing contractor unit prices were used. IPL is currently under contract with several vendors that have fixed labor pricing for units of work. IPL leveraged the unit pricing contracts to determine the labor costs for these projects. See Appendix 8.8 for an example of a confidential Class 2 estimate.

4.4.2 Class 3 Estimate Development

Class 3 estimates were developed for XLPE Cable Replacement, Pole Replacements, Steel Tower Life Extension and Distribution Automation Projects using unitized costs. Class 3 estimates were utilized because these project types are low complexity and high-volume projects. The scope of the work is known at a broad level and variation in the scope of work does not drive significant changes in project costs. There is no retirement or maintenance cost included in the Class 3 estimates. For example, the Pole Replacements Project cost estimate was developed based on a wood pole inspection failure rate of 2% for a total of 330 inspection failures annually. The pole replacement cost is based on unitized labor and material rates. IPL estimated the number of pole types (of the 330 average annual failures) that would fail inspection. The estimated individual pole replacement types were then multiplied by the corresponding unit replacement cost. This in turn determined the annual cost of the Pole Replacement Project. Annual variation in the reject rate through the 7- Year Plan is expected. This variation may cause annual variances; however, the Pole Replacement Project cost should normalize around estimated cost of the Project. As poles fail inspection through the life of the TDSIC Plan, detailed engineering will be completed. The cost of these Projects will be updated during the TDSIC annual update as necessary or appropriate. See Appendix 8.9 for an example of a confidential Class 3 estimate.

4.4.3 Class 4 Estimate Development

Class 4 estimates were developed by using unitized costs as well. The unitized costs are parametric or typical costs for similar scopes of work. Class 4 estimates were used uniformly on project costs for Plan Years 3-7. Estimating cost of projects in the later years of the Plan with Class 4 estimates is appropriate due to the uncertainty of future costs and limited scope defined. IPL incorporated the results of the labor costs from the bid events for Class 2 estimates into the Class 4 estimates where applicable. The results of the Class 2 estimates combined with internal subject matter expert judgement on unitizing costs were also incorporated into the Class 4 estimates. There is no retirement or maintenance cost included in the Class 4 estimates. For example, to create a unitized cost to rebuild 1-mile of 3-phase, 13.2 kV distribution line, all the components of a "typical" 1-mile segment of line were identified and itemized. The labor component of the cost was determined by contracted unit pricing and the material cost was derived from IPL's material management system. From this a unitized cost per mile was developed for a "typical" 1-mile section of overhead 13.2 kV distribution. This 1-mile unitized cost was applied to each mile identified in the Risk Model for replacement for years 3 through 7. The cost of these Projects will be updated during the TDSIC annual update as necessary or appropriate. See Appendix 8.10 for an example of a confidential Class 4 estimate.

5 Independent Review of Project Cost Estimates

5.1 Black and Veatch's Independent Review of Project Cost Estimates

IPL engaged B&V to conduct a review of its proposed TDSIC Plan capital cost estimates and estimating process, based on B&V's knowledge and experience with similar capital cost estimates. The review tested estimates for reasonableness based on B&V's experience and the information and backup data received from IPL for its cost estimates.

The specific goals of the independent cost review were:

- To validate that the IPL cost estimating process is in accordance with AACE guidelines; and
- To identify any recommendations for improvement.

B&V's review included IPL's cost estimating process for all projects and an independent estimate verification for a representative sample set of Class 2 project cost estimates from IPL's TDSIC Plan. As part of the review, B&V supported IPL with the development of a uniform method and template for cost estimating to meet AACE Class 2, 3 and 4 guidelines for all project cost estimates. Class 3 and 4 estimate templates completed by IPL subject matter experts were reviewed by a B&V AACE certified estimator for reasonableness. B&V developed independent project estimates for a 5% sample of Class 2 project estimates to verify reasonableness of estimation and completeness of project details.

Black & Veatch's review shows that the IPL cost estimates and cost estimating process are reasonable and consistent with AACE guideline classification. The level of detail IPL used to estimate T&D project cost estimates in its TDSIC Plan is consistent with common practice within the industry. The B&V Cost Estimate Review and Validation Report is included with the IPL TDSIC Plan as Appendix 8.6.

6 TDSIC Project Narratives

6.1 Circuit Rebuilds

Table 6.1.1 – Circuit Rebuilds Project Overview

Project Attribute	Description
TDSIC Activity	IPL will rebuild approximately 406 miles of 3-phase, 13.2 kV overhead distribution lines, on 198 different circuits.
Project Costs[13]	$298.7 million -- capital expenditure.

6.1.1 Background

IPL owns, operates, and maintains transmission and distribution lines located throughout its service territory. The system is essential infrastructure for the safe and reliable delivery of electricity to IPL's customers. The circuit assets evaluated as part of the Circuit Rebuilds Project include wood poles, towers, overhead transmission conductor, overhead distribution conductors and underground cable. Table 6.1.2 provides a summary of the T&D circuit asset base evaluated as part of the Circuit Rebuilds Project.

Table 6.1.2 – Circuit Rebuilds Project T&D Asset Base Summary

Asset Type	Units	Total
Transmission	circuit miles	685
Sub-Transmission and Primary Distribution Overhead (OH)	circuit miles	3,580
Sub-Transmission and Primary Distribution Underground (UG) – Jacketed ONLY	circuit miles	3,278
Total	circuit miles	7,542

Nearly 10 years ago, IPL developed a robust asset management framework and started collecting asset health and consequence information for the more critical assets base (i.e., power transformers and breakers). This effort has proven valuable in managing risk and deploying capital efficiently. As a next step, IPL contracted with BMcD to develop a Risk Model that included

[13] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year detail.

circuit assets. The Risk Model normalized risk across substations and circuits while also providing a methodology to efficiently allocate capital across the T&D system to maximize risk reduction.[14] The Risk Model identified high risk assets and then prioritized replacement based on risk reduced per dollar invested.

IPL used the Risk Model to evaluate the circuit assets at the overhead span level and the underground segment level. An overhead span asset includes a pole and a span of wire connected at the pole up to but not including the next adjacent pole. An underground segment asset includes underground cable between two termination points on the underground system. IPL evaluated circuits at the overhead span and underground segment level using the Risk Model to identify only the portion of each circuit with the highest risk. The high-risk spans and segments were then aggregated at the circuit level and then prioritized for replacement based on overall risk level per mile. Table 6.1.3 shows the results of the Risk Model for the circuit assets in 2026, if no TDSIC investment plan is implemented. Table 6.1.4 shows the results if the IPL TDSIC Risk-Based Scenario is implemented. The counts in each box represent the number of circuit miles in each risk category. This was calculated using the weighted average likelihood of failure and consequence of failure per mile, normalized by circuit length.

Table 6.1.3 – Circuit Heat Map 'Do Nothing' Scenario

		2026 'Do Nothing' Risk Profile Circuit Miles Count (excludes 4kV and Unjacketed Projects)					Total
Likelihood of Failure	Very High - 5	0	0	0	0	[illegible]	0
	High - 4	0	0	0	0	1,337	1,337
	Moderate - 3	[illegible]	0	0	25	3,264	3,289
	Low - 2	[illegible]	1	0	407	2,105	2,512
	Remote - 1	[illegible]	[illegible]	24	0	256	404
	Total	0	125	24	432	6,961	**7,542**
		Very Low	Low	Moderate	High	Very High	
		Consequence of Failure per Mile					

1,337 miles, or 18%, in High-Risk Region.

Table 6.1.4 compared to Table 6.1.3 shows the risk reduction provided by the Risk-Based Scenario. With a targeted approach of 406 miles of replacement on 198 circuits, a comparison of the two tables shows a reduction of 1,215 circuit miles out of the high-risk reduction region. Table 6.1.4 does indicate future investment will be needed with nearly 2,500 miles in the LoF 3 category.

[14] See Appendix 8.3 of IPL's TDSIC Plan for discussion of the Risk Model developed by BMcD and of details regarding the various investments.

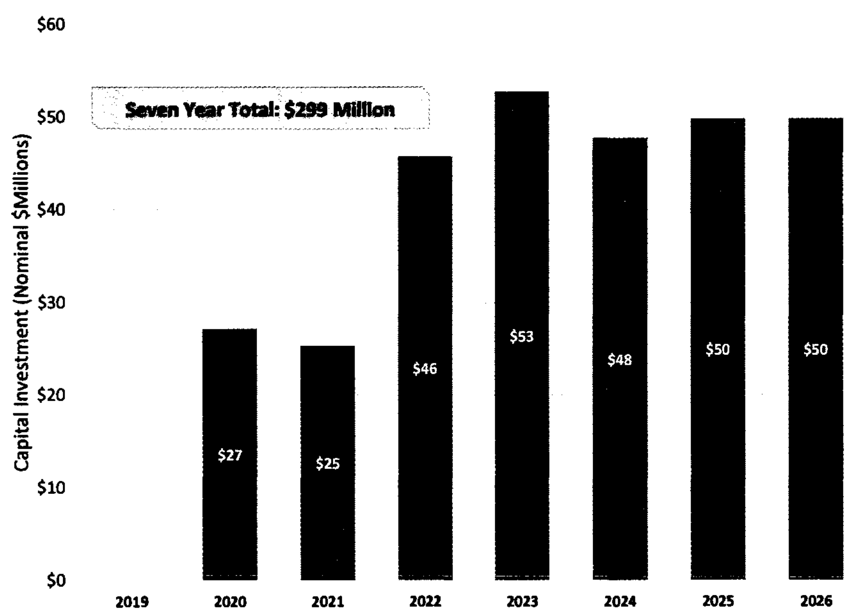
Table 6.1.4 – Circuit Heat Map Post IPL TDSIC Plan

Likelihood of Failure	Investment Plan Risk Profile Circuit Miles Count (excludes 4kV and Unjacketed Projects)					Total
Very High - 5	0	0	0	0	[illegible]	0
High - 4	0	0	0	0	122	122
Moderate - 3	[illegible]	0	0	25	2,494	2,520
Low - 2	[illegible]	1	0	407	3,894	4,301
Remote - 1	[illegible]	[illegible]	24	0	451	599
Total	0	125	24	432	6,961	**7,542**
	Very Low	Low	Moderate	High	Very High	
	Consequence of Failure per Mile					

122 miles, or 2%, in High-Risk Region.

Figure 6.1.1 shows the annual capital investment corresponding to the risk reduction shown from Table 6.1.3 to Table 6.1.4.

Figure 6.1.1 – Circuit Rebuilds Improvement Capital Investment Profile



6.1.2 TDSIC Purposes

The Circuit Rebuilds Project will provide resilience and hardening to the electric distribution system along with modernizing the system to enable distributed energy resources easier access to the grid. This project will also maintain the integrity and safety of the electric distribution system.

6.1.3 Description of Physical Improvements

IPL will rebuild approximately 406 miles of overhead 3-phase 13.2 kV circuit on 198 circuits. These circuits will be rebuilt using a standard 477 ACSR conductor which provides 13% more ampacity and 66% more strength than the existing 397 AAC conductor. Where existing circuits are in difficult access areas the Circuit Rebuilds design will attempt to relocate the circuit to accessible ROWs. During the execution phase, engineering teams will determine if any of the existing assets meet the current design standard. If they do, those assets will not be replaced as part of the Circuit Rebuilds Project.

6.1.4 Benefits of Circuit Rebuilds Project

The Circuit Rebuilds Project will provide the following benefits:

Safety

By replacing aged and deteriorated circuit assets IPL will be better positioned to maintain and operate a safe electrical system. By systematically and proactively replacing these assets IPL avoids the consequences associated with these asset failures. This in turn makes the IPL electric system safer for the public and IPL employees.

Improved System Hardening

Rebuilding high risk overhead spans will make the electric system stronger. Existing overhead spans will be replaced with stronger and taller poles and will have larger and stronger conductors. This means fewer broken poles and wires during weather events. This in turn improves reliability.

Improved System Resiliency

While outages will still occur during weather events, with fewer broken poles and wires the electric system becomes more resilient. Restoring power is quicker with fewer broken poles and wires. This in turn decreases the duration of interruptions of service, improving system reliability.

Enables Distributed Energy Resources

By rebuilding with larger current carrying capacity conductors, the IPL electric distribution system will be able to onboard more distributed energy resources with reduced impact to the electric system. As more distributed energy resources are added to the electric system, larger current carry capacity will be needed for bi-directional load flow on the distribution system.

Reduces System Risk

The Circuit Rebuilds Project lowers overall system risk on the IPL electric system by lowering the likelihood of assets failing and the associated consequence of the failures.

6.1.5 Summary

The Circuit Rebuilds Project will enhance system reliability, help maintain system safety along with enabling the modernization of the energy delivery system. The combination of these impacts reduces the overall system risk of the electric system.

6.2 Substation Assets Replacement

Table 6.2.1 – Substation Assets Replacement Project Overview

Project Attribute	Description
TDSIC Activity	IPL will replace high risk assets at 70 of IPL's transmission and distribution system substations. The work includes the replacement 11 power transformers, 560 breakers, and 60 batteries, for a total of 631 major substation assets.
Project Costs[15]	$248.1 million -- capital expenditure.

6.2.1 Background

IPL owns and maintains a large fleet of T&D substations located throughout its service territory. The substations are essential infrastructure for the safe and reliable delivery of electricity to IPL's customers.

To manage these and other assets, over the last decade IPL has been developing an asset management framework and program. As part of this framework and program, IPL developed asset health scores to assess the condition of power transformers and breakers. Additionally, IPL created consequence scores for these assets. IPL deployed data collection technologies and built the IT infrastructure to collect, store, and assess this asset health and consequence information. IPL has leveraged the asset health data to target conditioned based maintenance. With this asset management practice in place, IPL has been able to extend the expected average service lives of the substation asset.

As a next step, IPL contracted with BMcD to further develop a Risk Model that included 217 power transformers, 1,359 breakers, and 114 batteries for a total substation asset count of 1,690. [16]

Relevant to this Project, the Risk Model identified high risk assets and then prioritized replacement based on risk reduced per dollar invested. As explained below, the Substation Assets Replacement Project replaces the substation transformers, breakers and batteries identified as High Risk of failure in the BMcD modeling.

Table 6.2.2 shows the results in 2026 of the Risk Model for the substation assets if no TDSIC investment plan is implemented. Table 6.2.3 shows the results of the Risk Model if the IPL TDSIC

[15] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

[16] See Appendix 8.3 of IPL's TDSIC Plan for discussion of the Risk Model developed by BMcD and of details regarding the various investments.

Risked-Based Scenario is implemented. The counts in each box represent the number of assets with the associated likelihood and consequence of failure. Table 6.2.2 shows, 19 percent of the substation asset base is in the high-risk region (outlined in red) where assets have a high and very high likelihood of failure with a high and very high consequence of failure.

Table 6.2.2 – Substation Heat Map in 'Do Nothing' Scenario[17]

		2026 'Do Nothing' Risk Profile: Asset Count (excludes 4kV conversion and remote end breaker assets)					Total
Likelihood of Failure	Very High - 5	0	1	2	8	[illegible]	134
	High - 4	0	0	1	57	102	160
	Moderate - 3	[illegible]	6	3	203	267	479
	Low - 2	[illegible]	7	1	119	108	236
	Remote - 1	[illegible]	[illegible]	8	232	244	487
	Total	1	17	15	619	844	1,496
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
		Consequence of Failure					

290 assets, or 19%, in High-Risk Region.

Table 6.2.3 – Substation Heat Map in IPL TDSIC Scenario[18]

		2026 Investment Plan Risk Profile: Asset Count (excludes 4kV conversion and remote end breaker assets)					Total
Likelihood of Failure	Very High - 5	0	1	0	0	[illegible]	1
	High - 4	0	0	1	0	0	1
	Moderate - 3	[illegible]	6	3	90	87	186
	Low - 2	[illegible]	7	2	116	146	271
	Remote - 1	[illegible]	[illegible]	9	416	608	1,037
	Total	1	17	15	622	841	1,496
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
		Consequence of Failure					

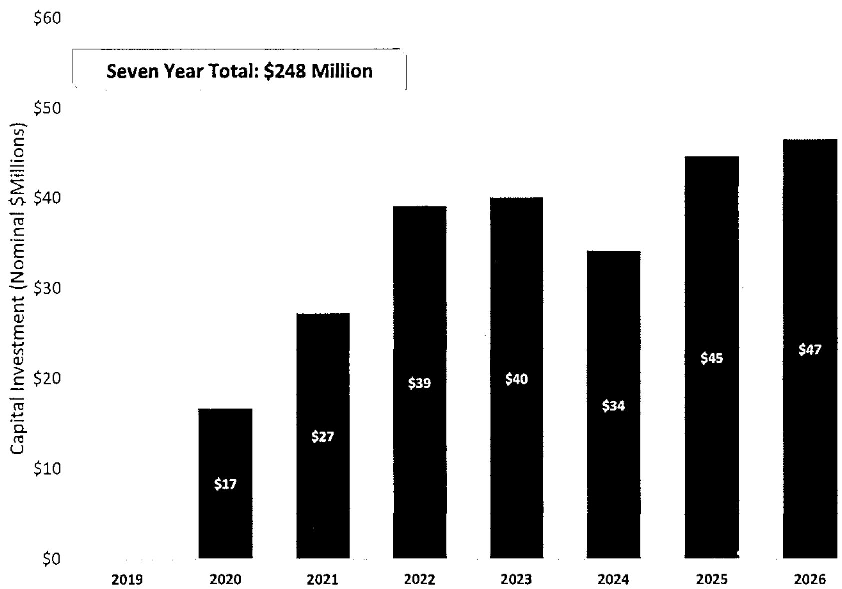
0 assets, or 0%, in High-Risk Region.

Table 6.2.3 shows the risk reduction provided by the IPL TDSIC Scenario. Table 6.2.3 shows no assets in the high-risk region and only 2 low consequence assets with a high or very high likelihood of failure. Additionally, the table indicates continuous future investments will be needed. For example, over time assets in the moderate LoF category will move into the high-risk

[17] This is a modification of Figure 1-2 from the Burns & McDonnell Report to exclude the 4 kV conversion and remote end breaker assets.
[18] This is a modification of Figure 5-8 from the Burns & McDonnell Report to exclude the 4 kV conversion and remote end breaker assets.

region. IPL's strategy to manage the risk of the 188 assets is continuous monitoring of asset health data and preventive maintenance. Figure 6.2.1 shows annual capital investment corresponding to the risk reduction show from Table 6.2.2 to Table 6.2.3.

Figure 6.2.1 – Substation Assets Replacement Capital Investment Profile[19]



6.2.2 TDSIC Purposes

This Substation Assets Replacement Project meets TDSIC purposes in two ways. The key purpose is to address aging substation infrastructure by targeting capital on high risk substation assets. By proactively replacing high risk assets IPL will improve safety and system performance. By replacing the identified high-risk assets with new modern equipment, IPL will move to a more enabled and modern electric system.

6.2.3 Description of Physical Improvements

The Substation Assets Replacement Project includes replacement of 11 power transformers, 560 breakers, and 60 batteries at 70 different substations. Of these replacements, 477 of the 560 breakers are metalclad medium voltage switchgear type and the remainder being open air breakers. The replacements will be performed over a seven-year period. See Appendix 8.7 for year by year project detail.

[19] Adaptation of Figure 5-7 of the Risk Model Report to exclude circuits, remote end breaker and relays, and 4 kV conversion.

6.2.4 Benefits

This Substation Assets Replacement Project will provide various benefits as described below:

Reduce Substation System Risk

The substation assets identified for replacement by the Risk Model will improve overall system performance and reduce risk by making substations more safe, reliable and efficient while modernizing the grid.

Replaced Assets Will Be Modernized

Breakers - Breakers will be replaced with newer technology. The new breakers will have higher fault current interrupting and increased load current carrying capabilities with microprocessor relaying. Breakers that are part of metal clad switchgear replacement will be equipped with remote racking. The new microprocessor-controlled relays provide advanced protective schemes capabilities, system event forensic information and advanced monitoring and control of the breaker.

Power Transformers - New power transformers will be equipped with continuous Gas Analysis monitoring. This monitoring provides higher resolution on the health of the power transformer allowing IPL to take corrective action sooner, avoiding potentially damaging the transformer.

Station Battery – New station batteries will have increased capacity for operating digital relays. They will be equipped with improved protections schemes and have continuous, hydrogen monitoring.

Reduced Maintenance Cycles – The new modern substation equipment has longer durations between maintenance cycles relative to the existing equipment.

6.2.5 Summary

The Substation Assets Replacement Project replaces the highest risk substation assets in IPL's energy delivery system. By replacing and modernizing IPL's assets in this category, IPL will enhance its ability to operate and maintain the Bulk Electric System and the distribution system more safely and reliably. These substation improvements play a major role in reducing IPL's total system risk.

6.3 XLPE Cable Replacement

Table 6.3.1 – XLPE Cable Replacement Project Overview

Project Attribute	Description
TDSIC Activity	IPL will replace or extend the life of approximately 3.6 million feet (686 miles) of existing Cross-Linked Polyethylene (XLPE) type cable that serves predominately residential distribution service areas. Existing XLPE type cable will be tested to determine whether it is capable of being injected with a healing fluid to extend its life 25 years. If the cable is not able to be injected it will be replaced with a longer life Ethylene Propylene Rubber (EPR) type cable.
Project Costs[20]	$86.2 million -- capital expenditure.

6.3.1 Background

The XLPE type cable is predominately buried within utility easements, underneath streets, alleys, sidewalks, and backyards. The cable has an exposed neutral conductor wound overtop a protective semi-conducting shield that covers the electrical insulating material. Since its initial installation, the XLPE cable has been prone to premature failure due to insulation break down from water exposure. As such, this cable has a poor performance record on the IPL distribution system. XLPE cable failures cause customer power outages and costly emergency repairs.

High failure rates of XLPE type cable is a utility industry issue not unique to IPL. Utility best practices for addressing the high failure rates of XLPE type cables can be described as a two-tiered approach. First, the cable is assessed to determine if it can be injected with a healing fluid that enables the XLPE insulation to regain its strength. If the cable can be injected, the healing fluid extends the life of the cable 25 years at a much lower cost than replacing the cable.[21] Second, if after the assessment the cable is determined not to be a candidate for injection, the cable is replaced.

IPL has been using this two-tiered approach to address XLPE failure rates since 2011. From this experience XLPE has seen a cable injection rate of 40%, meaning that after the assessment, 40% of the cable is capable of being injected, avoiding the higher cost replacement alternative. This acceptance rate is used to calculate the overall cost of the XLPE Cable Replacement Project.

[20] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.
[21] For further information on injection of cable to extend its life see http://www.novinium.com.

Figure 6.3.1 - High Failure Rate XLPE URD cable

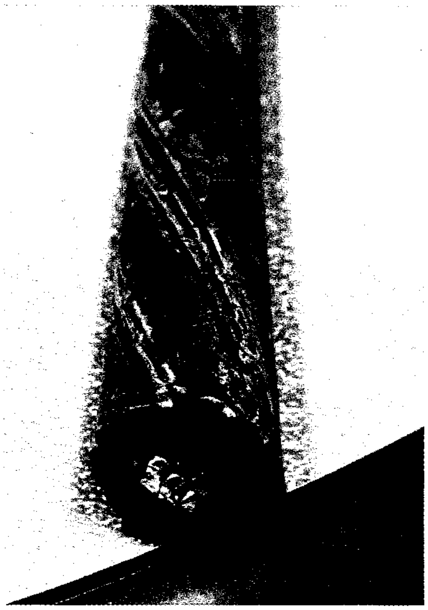
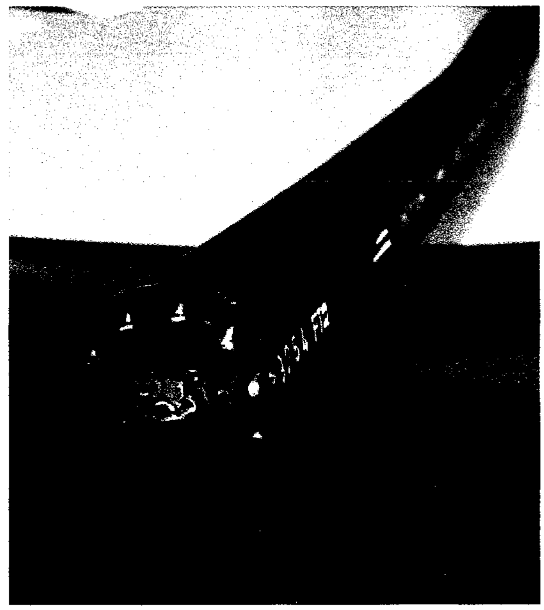


Figure 6.3.2 - New EPR cable with 45-50-year life



6.3.2 TDSIC Purposes

The XLPE Cable Replacement Project meets TDSIC purposes by improving reliability to customers served from the cable targeted for injection or replacement. The replacement cable is a modern cable design using EPR insulation that has a life expectancy of 45-50-years. The EPR replacement cable will provide long term reliability during this period. Fewer cable failures also means less time spent locating and isolating faulted sections of cable, reducing operational costs. Fewer faults result in improved safety because there will be fewer excavations associated with faulted cable repairs, often in difficult field conditions.

6.3.3 Description of Physical Improvements

IPL has knowledge of the specific locations of the high failure rates on existing XLPE cable from its outage management system. In the first years of the plan, high priority areas with elevated failure rates will be targeted. Along with the high priority targeted approach, IPL will address cable injection/replacement from a system wide review of the remaining service territory to avoid future failures from occurring.

For cable replacement, IPL will use horizontal directional boring methods along with hydro-vac trucks for pot holing. Open excavations will be kept to a minimum. These methods are recognized by Common Ground Alliance (CGA) as best practices in the utility industry.

6.3.4 Benefits

The following benefits are associated with this XLPE Cable Replacement Project:

Reliability Improvement

By replacing or injecting 3.6 million feet of XLPE cable, IPL will experience fewer permanent fault conditions. This will improve customer reliability by lowering the number of outages experienced.

Less Unplanned Work

Reducing cable faults reduces the need to dispatch qualified electrical workers and equipment to restore power.

Safety

Because there will be fewer field repairs, IPL employee and public safety risk is improved.

Risk Reduction

Replacement of the XLPE cable with new EPR cable lowers the risk on the distribution system and is part of the overall risk reduction score calculated by the Risk Model.[22]

6.3.5 Summary

IPL's XLPE Cable Replacement Project identifies deteriorated XLPE cable on the electric distribution system and replaces or injects it. This Project will improve service reliability for customers served directly from the circuits with XLPE cable.

[22] See IPL's TDSIC Plan Appendix 8.3 for Risk Model Report.

6.4 4 kV Conversion

Table 6.4.1 – 4 kV Conversion Project Overview

Project Attribute	Description
TDSIC Activity	IPL proposes to convert its remaining 4 kV general distribution circuits[23] and associated infrastructure to 13.2 kV. The current 4 kV system serves approximately 14,420 residential and small commercial customers in the north and northeast side of the Indianapolis downtown.
Project Costs[24]	$92.0 million – capital expenditure.

6.4.1 Background

Approximately 14,420 (3%) of IPL's residential and small commercial customers are served by IPL's increasingly obsolete 4 kV distribution system. The 4 kV system was installed during the 1940s and 50s. At the time, it was a reliable and cost-effective distribution primary voltage standard. Portions of the service area served by the 4 kV system are experiencing a revitalization of residential and commercial properties. Over the last three decades, IPL has converted most of the 4 kV system, upgrading it to the current standard 13.2 kV primary voltage. When the 4 kV load is converted to 13.2 kV it is tied into a larger distribution network with many different paths for service restoration. The remaining 4 kV system is isolated from the broader 13.2 kV system. The isolation of the 4 kV system combined with condition of the substation and distribution equipment puts the load served from the 4 kV system at an increased risk of sustained outages.

6.4.2 TDSIC Purposes

The initiative aligns well with TDSIC purposes of safety, reliability and system modernization. IPL will address these criteria by eliminating an increasingly obsolete portion of its distribution system that is challenging to maintain. Many spare parts for the 4 kV substation equipment are no longer available. Converting the existing 4 kV circuits to 13.2 kV operation modernizes the electric distribution system to standard equipment used throughout the IPL system. Also, converting the 4 kV system to 13.2 kV operation will provide the needed capacity required for the neighborhood revitalization and contribute to local and regional economic development.

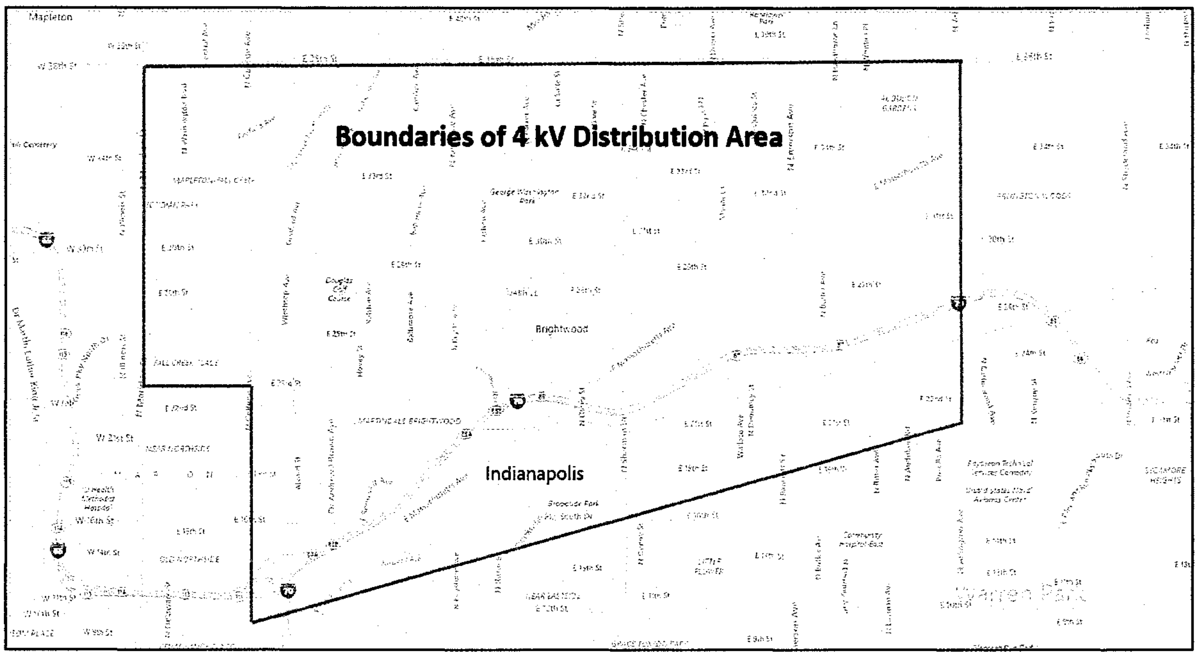
[23] The industrial customers receiving service at 4 kV are isolated from the general distribution 4 kV system and are not included in the TDSIC 4 kV Conversion Project.

[24] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

6.4.3 Description of Physical Improvements

IPL proposes to convert its remaining 4 kV distribution circuits, which serve the north and northeast side of the Indianapolis downtown. The approximate boundaries of the impacted area are I-65/I-70 loop on the south, Boulevard Pl. on the west, 38th St. on the north and Arlington Ave. on the east. This area measures at approximately 15 square miles and is depicted in Figure 6.4.1 below.

Figure 6.4.1 – 4 kV Conversion Project Area (~ 15 square miles, 14,420 customers)



The project work involves the following:

- IPL will rebuild 45 4 kV distribution circuits -- representing 393.5 conductor miles. These circuits will be built to today's 13.2 kV standards.
- Sixteen 34.5/4 kV substations will be retired.
- IPL will construct a new 138/13.2 kV substation to provide the needed circuit capacity for the proposed 4 kV conversion and to provide capacity for future growth. The new substation required for the conversion of the 4 kV load to the 13.2 kV system is considered under the Deliverability – Substation Design Upgrades portion of the plan.

6.4.4 Benefits

Conversion of the 4 kV system has the following benefits for the IPL system and IPL customers.

Replacing Obsolete and Aged Equipment

The remaining 4 kV system obsolete and is difficult to maintain. Converting the 4 kV system to 13.2 kV operation will bring the system up to current design standards and will allow for a common single voltage distribution network.

More Efficient Distribution Voltage

Converting the 4 kV system to 13.2 kV operation allows more load to be served in the area. The 13.2 kV system can deliver over three times the amount energy as the 4 kV system can with the same facilities in place. Also, line losses at 13.2 kV are nine times less than they are at 4 kV.

Incorporates the 4 kV Isolated Load Into the 13.2 kV System

Converting the 4 kV system to 13.2 kV operation provides access, to the existing customers served from the 4 kV system, to the larger 13.2 kV network that provides enhanced switching capabilities for outage contingencies and more interconnection opportunities in the future.

Retire Sixteen 4 kV Substations

By converting the 4 kV load IPL will be able to retire 16 old 4 kV substations and combine them into one new modern 13.2 kV substation.

6.4.5 Summary

In summary, the 4 kV Conversion Project addresses an important yet persistent pocket of aging infrastructure, which is experiencing increasing reliability and operational concerns as it ages and deteriorates. The conversion to 13.2 kV supports economic development and provides system modernization benefits such as maintenance efficiency, improved safety, performance risk, and line loss reduction.

6.5 Tap Reliability Improvement Projects

Table 6.5.1 – Tap Reliability Improvement Projects Overview

Project Attribute	Description
TDSIC Activity	IPL will improve reliability on distribution overhead fused tap lines that underperform. System improvements on identified tap lines will be achieved through conversion to underground, equipment replacement, reconfiguration and other methods. This Project will substantially improve the reliability for IPL customers served by the identified tap lines.
Project Costs[25]	$76.5 million -- capital expenditure.

6.5.1 Background

Utility primary distribution circuits consist of main line feeders with numerous lateral lines that are tapped from the main line. These tap lines often serve a small portion of customers and have fuses to isolate each tap line from the main feeder. The fuse disconnects the tap from the main line feeder and limits the customers without power to only those on the tap line when faults occur on the tap line. Some overhead tap lines experience a higher number of interruptions due to adverse weather and interference caused by the surrounding environment such as animals, equipment, and trees. Customers on these taps generally experience more power outages than other IPL customers. These overhead taps generally serve older, established residential neighborhoods. Further, years of gradual fence placement, vegetation growth, and other development often make these overhead taps difficult to access. Difficult access increases repair difficulty, potentially extending the duration of interruptions when they occur.

Each tap is unique having a different mix of outage causes, configuration and physical condition. Reliability can be improved by identifying and assessing taps with a higher number of outages and implementing measures to improve the tap line performance.

6.5.2 TDSIC Purposes

Consistent with TDSIC requirements, this is a distribution project to improve reliability and safety. The primary purpose is to reduce the number of sustained outages on poor performing overhead fused taps. The project improves safety by reducing the potential for interference with the 7.6 kV overhead lines. The project also reduces line repair and clearance costs.

[25] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

6.5.3 Description of Physical Improvements

Every 12 months, IPL will select a candidate list of tap lines based on the previous 36 months of historical performance for number of events and impact on customers. IPL will evaluate improvement options and generate a list projects to be worked for the following year. For TDSIC Plan Year 1, twenty improvement projects have been identified based on this criterion at an estimated cost of approximately $10.5 million. For the remaining six plan years, approximately $10 million has been allocated to address tap lines and the specific improvements will be made based on historical performance as noted above. Taps with the worst performance will naturally have the higher priority. Reliability improvement treatment will be applied as appropriate to all lines downstream from the selected tap point.

IPL will use a variety of methods to improve reliability on these tap lines. Some will have replacement of older equipment such as cross arms, self-protected transformers, surge arresters and insulators with new equipment. A few may be reconfigured to reduce exposure. Many overhead taps will be converted to underground.

For those fused taps that are candidates for converting from overhead facilities to underground, IPL will find suitable routes for the cable and find appropriate transformer service locations.

6.5.4 Benefits

IPL's Tap Reliability Improvement Projects targets taps prone to reoccurring outages. Because this Project addresses the underlying outage causes this Project provides reliability benefit for the affected overhead taps.

Safety

Overhead taps that are converted to underground reduce the potential for the overhead facilities to be exposed to environmental factors, such as animals, public, and trees. Also, replacing older equipment reduces the probability of failure.

Reliability

IPL customers on these tap lines will see a significant improvement in reliability. For example, consider the work plan for 2020. The twenty tap lines in the 2020 plan cause 59 outages per year with an average duration of 8.9 hours per event. They account for 331 outage incidents for years 2016, 2017, and 2018. On average, about 75% of the outages caused by these tap lines will be eliminated.

Direct Repair and Maintenance Savings

Overhead tap outages are expensive to repair and contribute significantly to expenses. On average the cost per incident is about $3,000. This generates future direct savings of over $331,000 per year assuming an 75% improvement. The estimated future savings for line clearance is $43,300 per year.

Customer satisfaction

Frequent long-duration outages are a major source of dissatisfaction and complaints. This project will significantly improve the experience of customers that have historically been most impacted by these types of outages.

6.5.5 Summary

In summary, IPL's Tap Reliability Improvement Projects satisfies TDSIC requirements. It improves safety and reliability. It offers substantial reliability value to customers and will reduce upward pressure on operating costs which would otherwise be expected to increase as facility failures increase.

6.6 Meter Replacement

Table 6.6.1 – Meter Replacement Project Overview

Project Attribute	Description
TDSIC Activity	IPL will replace approximately 350,000 residential and small commercial single and three phase electric meters over a five-year period beginning in 2020. The planned deployment rate is approximately 5,833 per month.
Project Costs[26]	$55.9 million -- capital expenditure.

6.6.1 Background

In 1997, IPL began moving toward an Automatic Metering Reading (AMR) system. This represents a first generation of meter automation but today it is a legacy system. IPL implemented the AMR technology by retrofitting its existing electro-mechanical meters with an AMR communication module. The AMR module counts meter dial rotations and then communicates this information to collectors in a one-way communications mode. The AMR communications module was installed with an expected average service life of 20 years. As a practical matter, this means that some meters will fail before 20 years while others will continue operation to or beyond the 20-year mark.

In 2013, IPL began to upgrade the AMR network to accommodate Advanced Metering Infrastructure (AMI) meters. The AMI meter is much different than the AMR meter, as the communications is integral to the meter (versus the AMR retrofit approach), and it comes equipped with a connect/disconnect switch and other advanced metering functions (like voltage measurement). The AMI migration effort began with an update to the communication system to enable it to read both types of meters. This prudent investment laid the foundation for transitioning to the next generation of automated meter technology as the AMR technology reached the end of its useful life.

By 2013, IPL was experiencing an increase in AMR communication module failures. With an updated meter communications network in place, IPL started swapping failing AMR-equipped meters with an AMI meter. IPL's recent practice has been to change the meter when it failed and when the site was visited for another purpose, such as a "last read" trip meter read when a residence was being transferred to a new owner. Because these meter swaps are reactive in nature and the timing or location of their occurrence cannot be predicted, the AMI meters are

[26] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

scattered throughout the IPL service territory. As of December 31, 2018, 144,000 of IPL's original AMR meters are now AMI-equipped.

Since 2013, the average annual AMR-equipped failure rates have doubled from less than 1% in 2013 to over 2% in 2018. The increasing failure rate reflects the AMR modules reaching or exceeding the expected average 20-year service life. To put perspective around meter failures, during the last two weeks of October 2018, IPL detected 360 AMR-equipped meters failed to communicate with the network and thus required a replacement on an expedited basis. An emergent increase in the work load like this presents challenges and inefficiencies.

As the AMR population ages and the number of meters exceeding the 20-year expected service life grows, IPL reasonably expects the AMR failure rate will increase beyond 2018's 2% level. The increasing failure rate poses a risk to the operation of the distribution system and the customer experience. Addressing this increasing risk in a proactive manner is more efficient than addressing it through reactive, unplanned trips. The proactive replacement of the remaining AMR meters as part of the TDSIC Plan mitigates the risk of AMR failures and allows the operational and other benefits of AMI technology to be secured in a timely manner.

6.6.2 TDSIC Purposes

This Meter Replacement Project meets TDSIC purposes in several ways. By proactively completing the migration to advanced metering, IPL will modernize its electricity delivery system and provide operational and other customer benefits while avoiding the negative effects of the increasing AMR-equipped meter failures.

The Meter Replacement Project will improve safety. With AMI meters, IPL is able to more safely connect, disconnect and reconnect customers (without, for example, entering customer back yards). Field trips – and related vehicular travel – will be reduced significantly. Theft and tamper circumstances (involving theft of power, usually in unsafe ways) can be more quickly detected and resolved.

The completion of the AMI migration will improve the IPL distribution system operation and reliability. For example, meter-provided equipment loading diagnostics will allow IPL to proactively detect potential equipment malfunctions, such as transformer overloads. AMI will also improve IPL's outage response capabilities in response to isolated incidents, (also known as "blue sky" "single lights out" conditions) as well as during major storm outage conditions.

6.6.3 Description of Physical Improvements

IPL will procure, test, program and install approximately 350,000 advanced, two-way communicating single phase and three phase meters from a leading meter manufacturer. These meters will be deployed to IPL's residential and small commercial customers using existing processes already in place.

6.6.4 Benefits

IPL made the prudent decision to enable its network to read AMI meters for the purposes of migrating from AMR to AMI, which provides the next generation of automation benefits as described below:

Engineering and Distribution System Operational Benefits

AMI improves the utility with new monitoring and diagnostic tools, which help the IPL distribution engineers manage the grid more effectively. For example, the AMI meters provide the means to monitor the health of electric power distribution network equipment (such as transformers, capacitor banks, electrical connections, voltage conditions, power harmonics).

AMI, for example, can help IPL verify meter wiring configurations, can help predict distribution transformer loading (and potential for overloading and therefore the risk of damage), and can monitor voltage sags and swells with changing circuit conditions. This type of information helps the distribution engineer address circuit problems proactively and leads to improvements to the customer's power quality and reliability.

Finally, deployment of the AMI meters will facilitate the interconnection with customer sited Distributed Energy Resources ("DER") such as electrical vehicles, solar and wind.

Distribution Outages Benefits

AMI meters also provide significant benefits to outage management functions. The meters' 'last gasp' notices (upon loss of power) and restoration signals (when power is restored) provide valuable information to IPL's Outage Management System ("OMS"). This improves IPL's ability to understand the extent of outages and manage the restoration work during major outage events. The signals integrated into the IPL OMS improves service reliability, and greater levels of customer satisfaction.

Avoidance of AMR-related Meter Failure Costs and Risks

As stated above, by proactively replacing the AMR-equipped meters, IPL mitigates the increasing risk of AMR meter failure. Furthermore, as the level of failures grows, the complexities of managing the work also increases, particularly when the emergent work must be addressed within a compressed timeframe. There are cascading impacts as the level of urgent repair work grows and other routine work is deferred to allow the emergent work to be addressed.

Reduced Field Trips for AMR Meter Maintenance

IPL experiences a certain volume of field trips to AMR-equipped meters due to age-related failure and poor performance. The AMI system performs to a higher level of performance across the communications network and as part of the meter itself. Therefore, the number of meter maintenance field trips is expected to decline with fully implemented AMI. This cost will be reduced with AMI because this system is known generally to achieve a higher degree of monthly and daily read reliability and this is IPL's experience to date with its AMI system.

Reduced Field Trips for Disconnect and Reconnect Purposes

The AMI meter is equipped with an internal switch that can be activated and controlled over the communications system. Therefore, IPL's expansion of AMI meters will increase the automation of the distribution system and can reduce field meter service-related trips involving the disconnection and reconnection of meters. These may include trips when a customer is moving into or out of a residence. IPL also makes trips to the customer location to disconnect service for nonpayment and related reconnection of service once payment is made. The AMI automation can improve the efficiency of this process and lead to reductions in operating costs. The automated switch allows the field representative to perform the work more safely and quickly, thus making the trip more efficient. A reduction in the nature and number of site trips is expected to reduce the ongoing cost of this work. While IPL will continue to comply with IURC regulations regarding the disconnection to service, based on current field trip activity levels, IPL estimates that it will be able to re-assign six Metering Division field technicians to other responsibilities once AMI is fully installed.

It should be noted as well that these reductions in field trips reduce Metering Division costs for support equipment, vehicles, fuel, uniforms and other supplies. Also, of relevance is the improvement in safety to the customers and IPL's field workers who are no longer required to enter backyards and other locations to secure a last billing read or physically disconnect the meter.

Customer Care Benefits

AMI provides numerous benefits in the support of many customer care functions. AMI meter data is more granular than what is provided across the AMR meter network. With AMI, meter reads are available at daily, hourly, and sub-hourly levels of detail. This granular consumption information can help IPL's customer care agents assist customers more effectively when they inquire about their electricity use patterns and bills. This in turn should support ongoing customer satisfaction with their service.

The improved and more granular meter data also provides the foundation for customers to have better information about their energy use patterns and energy efficiency efforts. The two-way communications capability of the AMI meter system means that the IPL can automate the service reconnection process and thus allow timely (~ < 1 minute) reconnection of service following notice of bill payment. This can reduce the need for the customer to call the customer care center to inquire as to when service will be restored and thus reduce customer inconvenience (as the customer is provided with a fast fulfillment and restoration of the service upon payment).

Because IPL can remotely 'ping' the AMI meter, customer care representatives can often help a customer determine the power status of the meter. Customers sometimes call IPL inquiring about the loss of power in their homes, and this information can help troubleshoot whether the loss of power is on the customer-side (where the customer is responsible for arranging an electrician to troubleshoot the issue) or utility-side of the meter (where IPL is responsible for resolving the issue). This allows the customer to be informed of the nature of the service issue and avoids the cost of and time associated with an unnecessary field trip if the loss of power is on the customer side of the meter.

The completion of the AMI system will provide the foundation for new customer benefits which facilitate the provision of electricity to new and emerging technologies. The benefits of AMI justify the Meter Replacement Project when considering the full extent of AMI technology and the avoidance of AMR meter failure risks (as the AMR population ages, failure rates increase). Accelerating deployment of AMI in accordance with the Meter Replacement Project allows overall AMI benefits to be achieved sooner than the existing normal replacement plan. Further benefits are quantified in the below table.

Table 6.6.2 – AMI Meter Acceleration Benefits

AMI Meter Deployment Estimated Benefits Achieved Sooner with an Accelerated Plan		
Description	**Benefits**	
Accelerated Reduction in Metering Personnel	$	3,394,417
Savings Associated with Programmatic Replacement (Contractor dedicated to pro-active replacement)	$	11,550,000
Cost Reduction in Visits for Reconnects	$	2,662,200
Net Benefits of Accelerated Plan	**$**	**17,606,617**

6.6.5 Summary

In summary, IPL's Meter Replacement Project mitigates the risk of a reasonably expected increase in urgent meter replacements due to failed or failing AMR meters. The Meter Replacement Project enables the delivery of system operational and engineering benefits as well as customer care benefits made possible through the operation of an advanced metering network.

6.7 CBD Secondary Network Upgrades

Table 6.7.1 – CBD Secondary Network Upgrades Project Overview

Project Attribute	Description
TDSIC Activity	IPL will relocate targeted manhole and duct bank facilities, replace 15 kV feeder cables, 208 V network protectors and network transformers and install vault monitoring technology. IPL also plans to enhance the network System Controls and Data Acquisition ("SCADA") system and expand Distributed Temperature Sensing ("DTS") technology and add Distributed Acoustic Sensing ("DAS") technology to assist in monitoring and responding to potential network events. The combination of upgrades, rebuilds and replacement of equipment will improve safety, reduce the likelihood of network events and enhance operations.
Project Costs[27]	$39.0 million -- capital expenditure.

6.7.1 Background

The IPL underground secondary network is a complex system of transformers, network protectors and control equipment. This complex system is interconnected by primary, secondary and communication cables which are routed through underground duct lines, manholes and vaults. The secondary network is contained within a "Mile Square" area and is geographically located between North, South, East and West Streets in the Central Business District (CBD). There are approximately 625 miles of duct lines, 1,214 manholes and 140 network vaults in the secondary network area.

The environment in which the IPL underground secondary network operates consists of multiple underground utilities, city infrastructure and confined spaces making maintenance and construction difficult. The challenges in operating and maintaining a secondary network are:

1.) known utility conflicts – coordination between IPL facilities with other utility facilities.

2.) unknown utility conflicts - uncertainty of where other utility and obstructions are located.

3.) limited public right-of-way – limited real estate with multiple utilities and other services.

[27] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.8 for cost estimates and year by year project detail.

4.) coordination of work with planned city events – avoiding disruption for high profile events

5.) coordination of work in a vibrant city center – reducing impact on pedestrians, traffic and normal activities.

6.) aged infrastructure and equipment.

6.7.2 TDSIC Purposes

This CBD Secondary Network Upgrades Project meets TDSIC purposes in several ways. By replacing aged assets and relocating targeted assets away from existing heat sources within the secondary network, IPL will improve public and employee safety, reduce the likelihood of system events, and modernize a critical utility system in the heart of the city and thus support economic development.

6.7.3 Description of Physical Improvements

Targeted improvements in the CBD Secondary Network Upgrades Project are:

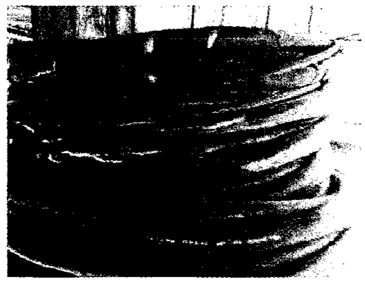
- Relocate and/or rebuild manhole and duct lines
- Replace 15 kV feeder cables
- Replace 208 V network protectors
- Replace network transformers
- Expand DTS technology
- Add DAS technology
- Enhance and expand Network SCADA capabilities

Implementation of proposed improvement plans, and system modernization is expected to better predict asset replacements before failure occurs, therefore reducing frequency of facility failures. The construction will occur over seven years with different components of the plan being spread systematically over the plan years to ensure workability and constructability in the CBD.

Relocate and/or rebuild manhole and duct lines

The Plan includes the relocating and/or rebuilding of (45) manholes and approximately 3,791 feet of duct line. Duct lines and manholes deteriorate over time due to water runoff from buildings and sidewalks. These conditions are not unique to IPL's secondary network system. Replacing duct lines and manholes is challenging. Digging beneath downtown streets may uncover obstacles that are difficult to remove or require an alternate route to be taken. Certain existing infrastructure locations are exposed to risk if left in place (e.g., elevated thermal conditions). Rebuilding or replacing manholes that are small (barrel brick design) will provide more working space for employees who enter them. Manholes targeted for replacement are cramped, have dirt floors with little or no room to work. Newer manhole designs will allow for worker movement and better organization of equipment for ease of access, worker safety and efficiency. Larger manholes also provide space for air circulation to help reduce exposure to combustible gasses. Also, through the strategic replacement and relocation of aged facilities away from underground heat sources there will be less likelihood of cable damage due to the damaging effects of heat. High heat conditions can rapidly deteriorate cable and infrastructure which can lead to a cable failure or breakdown of infrastructure.

Figure 6.7.1 - Two-Year-Old Cable Damaged by External Heat Source



Replace 15 kV cable

The Plan includes the replacement of approximately 48,609 feet of 15 kV primary feeder cable. Replacing poor performing 15 kV cable will reduce primary cable failure. Like many utilities, IPL installed XLPE cable on many of its primary feeders. The material used in the manufacturing of XLPE begins to breakdown prematurely, creating hair-line cracks in the insulation. This effect known as "treeing" allows water and containments into the cable which eventually leads to failure. As this type of cable fails in the IPL secondary network it is replaced with Okonite Okoclear and General Cable PowerNet cables. Proactively replacing the remaining XLPE cable in the secondary network will remove a known poor performing asset from the system. Also, improved public safety will be gained through the installation of low smoke low combustion primary and secondary cable. IPL will replace targeted primary and secondary cables with Okonite Okoclear (primary) and General Cable PowerNet (secondary) to help reduce exposure to combustible gasses.

Replace 208 V network protectors and targeted transformers

IPL will replace twenty-nine 208 V network protectors and thirty-two network transformers. Existing transformers and 208 V network protectors have been in operation for decades and sit in an underground environment. Even with routine maintenance programs some conditions and stresses are not easily detectable. Mechanical equipment operates, wears down over time and becomes less reliable. IPL replaced and upgraded 480 V network protectors to provide a safer work environment for employees. Replacing targeted transformers and 208 V network protectors will upgrade this part of the network system providing improved safety to employees. The new 208 V network protectors will be equipped with an Arc Flash Reduction Maintenance System (ARMS) and a "Stacklight" to indicate the breaker status and ARMS activation. These features will aide in reducing exposure to arc flash potential when working on a network protector.

Modernization of CBD Secondary Network

Modernization of the CBD will include expanding DTS by three fiber routes (approximately 10,000 feet of fiber per route) and adding four routes of DAS technology (approximately 32,000 feet of fiber per route). The innovative technologies helping IPL to modernize the secondary network system are the DTS and DAS systems. These technologies enable IPL to monitor conditions in real-time, pin-point problems and dispatch crews or contact other utilities to evaluate the situation. With fewer secondary network events there will be less overtime expense, fewer cable repairs that become weak points on a circuit and less stress on network equipment from high fault currents. The addition of the DTS routes will cover 100% of the infrastructure which currently cohabitates with heat sources.

DTS

DTS can alarm and locate high heat conditions using fiber optic technology to sense temperature changes (e.g., steam leaks, cable arcing) in duct lines and manholes. Being alerted of these abnormal conditions allows IPL to respond and act to limit or prevent damage to network facilities. Traditional cable fault locating can damage cable as a high DC voltage is applied across the cable to produce a high current and generate a loud "Thump" sound to be detected by field crews. Using DTS and DAS technology (discussed below) can help identify trouble areas and limit the need to thump cable.

DAS

DAS technology also uses fiber optics to listen and pinpoint sound. With the installation of DAS technology, this system will monitor audible disturbances that occur when 15 kV cables fail and locate the audible disturbance on a mapping system. The current method of locating cable failures can often take several hours and can degrade cable depending how long the failure locating process takes. In 2018, a proof of concept installation of the DAS system was successful and determined to have merit.

Enhance CBD Secondary Network System – SCADA System

The IPL plan includes installing (57) VaultGards, (114) water detection devices and (14) RTUs. As part of the vault monitoring technology plan IPL will enhance and expand CBD secondary network SCADA capabilities by adding Remote Terminal Units (RTUs), VaultGards (communication platform) and water level detection. Currently one VaultGard may serve as a communication platform for multiple network vaults making it difficult to trouble-shoot problems and less reliable as the connection between vaults is with twisted copper-pair wires. Adding VaultGards to each vault with fiber optic cable between vaults will reduce connection problems and increase the scan rate across the system allowing data to be transmitted faster. The network SCADA system will also incorporate water level detectors in each vault bay. This vault monitoring technology will provide notification to IPL operators that critical water levels are approaching; an alert system which does not exist today.

6.7.4 Benefits

The CBD Secondary Network Upgrades Project has many benefits for the IPL system and IPL's customers.

Safer and Better Organized Manholes

Considering the network infrastructure, some manholes are very small, barrel brick design, and limit accessibility due to the manhole size. Rebuilding these manholes will not only increase the size but will also allow for the installation of modular splices and racking systems that will improve the efficiency and safety of work being performed in the manhole.

Replacing Aging Infrastructure

Enhancements and upgrades to secondary network material and equipment will reduce the average age of system components within the secondary network system. This will help to make the overall secondary network system more robust and resilient to system conditions and continue to provide uninterrupted data during network events.

Performing at Expected Levels of a Major US City

Continued reliability in the secondary network will build value with businesses and confidence with customers and key stakeholders such as the Indiana Utility Regulatory Commission (IURC), Indianapolis Convention and Visitors Bureau (VisitIndy), City Government and the Capital Improvements Board of Marion County (CIB).

Modernizing Critical City Utility Infrastructure

IPL is applying advanced technologies to the CBD secondary network for increased intelligence of the health of the system, improved operational capabilities and better monitoring and control. The secondary network serves the central business district that drives the economy of Central Indiana. Indianapolis hosts multiple major sporting events and conventions for millions of visitors annually. Modernizing the CBD secondary network system will allow Indianapolis to continue to drive the growth of central Indiana.

6.7.5 Summary

Investing in a plan to modernize, upgrade, rebuild and replace facilities in and supporting the secondary network system will improve safety, reduce network events and enhance operations of the CBD secondary network. This project will allow IPL to better manage, operate and maintain the critical infrastructure that provides electricity to and supports economic development in the City of Indianapolis area.

6.8 Static Wire Performance Improvement

Table 6.8.1 – Static Wire Performance Improvement Project Overview

Project Attribute	Description
TDSIC Activity	This Project will replace approximately 84.3 miles of static wire on IPL's 138 kV transmission system with standard Optical Ground Wire (OPGW).
Project Costs[28]	$62.1 million -- capital expenditure.

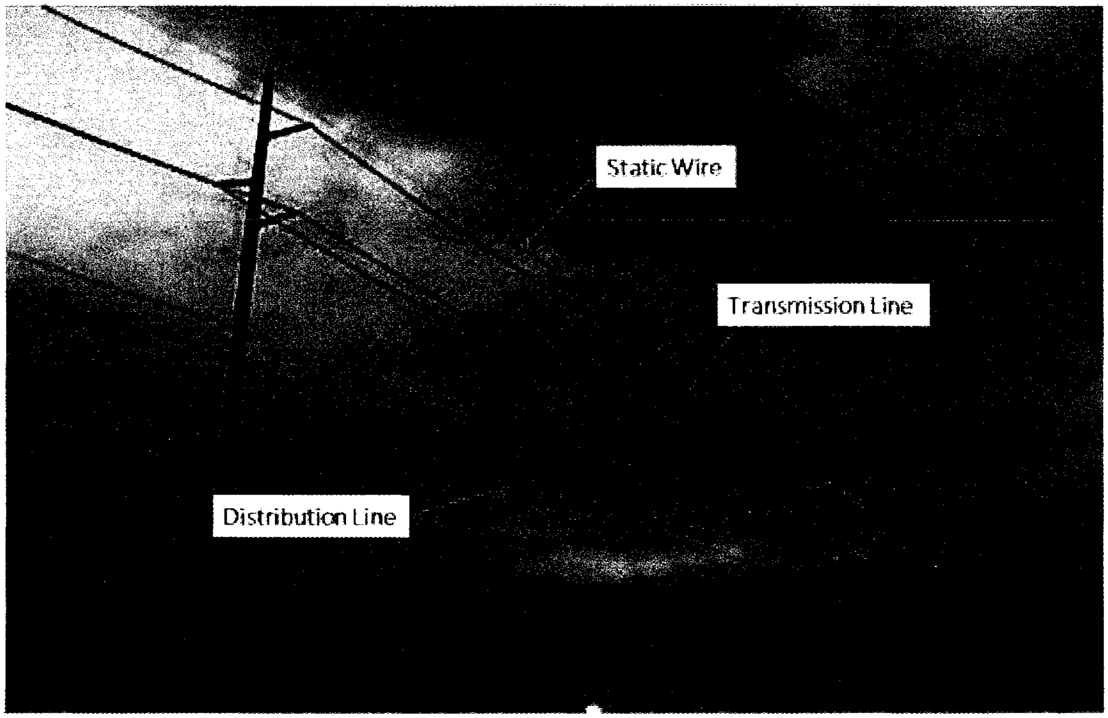
6.8.1 Background

Most overhead transmission lines are designed with a grounded wire at the top of the supporting structures above the phase conductors. This wire, commonly referred to as the "static wire" or "shield wire", is designed to protect the phase conductors from direct lightning strikes by directing the lightning induced current safely to ground. Further, the static wire serves as the return current pathway for fault current during system fault events.

Figure 6.8.1 illustrates the typical single pole transmission line and the location of where the static wire is on the transmission line.

[28] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

Figure 6.8.1 – Static Wire Location



This Project will replace, 68 miles of a specific type of static wire, 3#8 Alumoweld, that was installed on approximately twenty different 138 kV circuits constructed on single-wood poles when they were initially built. This static wire is deteriorated and is performing poorly. When the existing 3#8 Alumoweld static wire fails it falls into the energized transmission and or distribution circuits causing outages. The replacement for this static wire is IPL's current standard OPGW meeting specified outside diameter, strength and fault current capabilities. Since the early 1990s, OPGW has become an economical option for replacing transmission line static wire. The OPGW includes a core of glass optical fibers that provide a telecommunications path between the substations at each end of the transmission line while providing lightning protection for the circuit.

An additional 16.3 miles of existing static wire on the 138-kV system will be replaced with OPGW for improved relay protection. Upgrading the static wire on these lines ensures that the protection equipment on both ends of a transmission line are optimized for efficient, fast, and safe operations. Faults that are cleared faster from transmission lines reducing equipment damage and increases the system reliability and performance seen by our customers. IPL looks at the protection of a transmission line as a system which includes all equipment at both ends of the line.

6.8.2 TDSIC Purposes

This Static Wire Performance Improvement Project meets TDSIC purposes in several ways. This project will improve safety by reducing static wire failures on the IPL system thereby reducing exposing the public to fewer downed wires. The proposed use of OPGW modernizes IPL's electricity delivery system and provides operational and other benefits, such as minimizing the effect of momentary voltage dips (from static wire failures) and improving protective relay and system control and data acquisition (SCADA) communication. The improved relay protection decreases the duration of system faults and this in turn reduces the damaging effect on transmission system components.

6.8.3 Description of Physical Improvements

IPL will design and construct approximately 84.3 miles of static wire replacement on the 138 kV circuits identified below Table 6.8.2.

Table 6.8.2 – Work Plan for Static Wire Performance Improvement Project

Year	Miles	Circuit	Circuit Name
2020	1.73	132-44	Crestview - Northeast
2020	5.27	132-84	Mooresville - Camby
2020	3.75	132-24	MV Tap Switch - Mooresville
2021	3.15	132-35	Pike - Crawfordsville Rd
2021	2.77	132-05	Stout - Glenns Valley
2021	7.79	132-59	Southwest - Sanitation Southport
2021	1.08	132-70	Allison #4 - West
2021	1.21	132-61	Center - Lilly South
2021	1.39	2451-1	Center - Lilly Corp
2022	3.63	132-36	Edison - Brookwood
2022	3.11	132-41	Westlane - Georgetown
2022	4.23	132-28	Prospect - Ford
2023	3.39	132-46	Sunnyside - Geist
2023	1.60	132-51	German Church - Cumberland
2023	7.68	132-43	Guion - Crestview
2024	3.75	132-57	North - River Road
2024	3.05	132-55	Castleton - River Road
2024	5.45	132-52	Cumberland - Ford
2024	0.50	132-50	German Church - Sunnyside
2025	3.05	132-38	Brookwood - Lawrence
2025	2.91	132-49	East - Tobey
2025	2.89	132-68	Tobey - German Church
2025	2.76	132-32	Mill Street - Edison
2026	3.74	132-54	Castleton - Geist
2026	4.36	132-64	Rockville - Allison #4

As reflected in Table 6.8.2, IPL plans to implement this Static Wire Performance Improvement Project evenly over the seven-year TDSIC Plan period based on system protection priorities and will coordinate work on transmission lines with other substation work. IPL will seek to conduct this work in a way that minimizes transmission equipment outage potential.

6.8.4 Benefits

The Static Wire Performance Improvement Project has many benefits for the IPL system and IPL's customers.

Improved Bulk Electric System Performance

Replacing these static wires will improve system-wide performance during fault events by minimizing the number of 138 kV forced outages due to broken shield wire. This will avoid costs associated with emergency repair or replacement of failed static wire.

Safety

Reducing the number of failures has the added benefit of improving employee and public safety. Less static wires that fall in public areas of access minimize the likelihood of inadvertent public contact. Additionally, IPL crews will not have to respond to emergencies to repair downed static wires.

System Resiliency

This Project will add resiliency to the IPL BES by eliminating fault incidents and keeping transmission lines in service during adverse weather conditions.

Enhanced Relay Protection and System Control

Replacing the underperforming static wire with a suitable OPGW conductor provides the ancillary benefit of multiple, additional communication pathways for operating the system and improving relay protection and SCADA system performance. It also provides greater communications redundancy to accommodate various planned or unplanned outages.

Customer Benefits

The completion of this Project will improve the IPL transmission system operation and reliability. Customer operations and equipment, such as motors, can shut down because of voltage dips on the Bulk Electric System ("BES"). This can be a significant cost for large Commercial and Industrial ("C&I") customers. This Project will help reduce the likelihood of customer impacts from faults by removing faults from the system faster.

6.8.5 Summary

IPL's Static Wire Performance Improvement Project will reduce system disturbances providing better customer power quality and will improve the operational performance of IPL's transmission system.

6.9 Remote End – Breaker Relay/Upgrades

Table 6.9.1 – Remote End – Breaker Relay/Upgrades Project Overview

Project Attribute	Description
TDSIC Activity	This Project consists of replacing circuit breakers and/or electromechanical relays on the remote end of transmission lines opposite a circuit breaker identified for replacement by the Risk Model and included in the TDSIC Plan Substation Assets Replacement Project.
Project Costs[29]	$28.0 million -- capital expenditure.

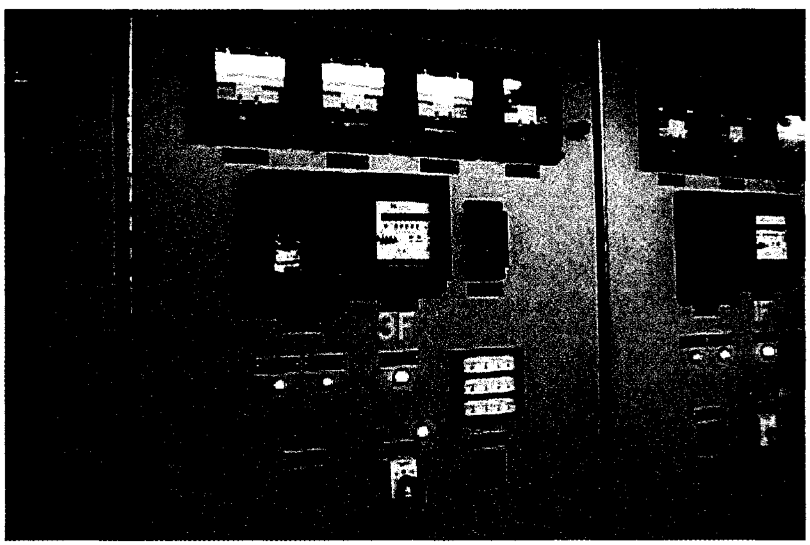
6.9.1 Background

The Remote End - Breaker Relay/Upgrades Project complements the breaker upgrades identified for replacement in the Risk Model and included in the TDSIC Plan Substation Assets Replacement Project. The Risk Model identified high risk transmission and sub-transmission (34.5 kV) line circuit breakers for replacement. The replacement of breakers includes the breaker equipment and, if needed, the protective relays associated with the breaker. Once these upgrades are completed the new breaker has enhanced capabilities above existing breakers that have not been upgraded. Representative pictures of the equipment targeted for replacement are set forth in Figures 6.3.1 and 6.3.2 below.

[29] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

Figure 6.9.1 – Oil Circuit Breaker Targeted for Replacement

Figure 6.9.2 – Electromechanical Relays Targeted for Replacement



To obtain the full benefits of the modernization associated with breaker replacements identified by the Risk Model, the breakers and relays at the remote ends of the transmission line needed to be investigated for deficiencies. IPL reviewed the list of breakers chosen by the Risk Model and evaluated the breakers and relays at the remote ends of those transmission lines. The review found that the breakers chosen for replacement, in some cases, left the remote end with equipment that would not allow the full capabilities of the modern equipment to be utilized. By upgrading both ends of the transmission line with modern breaker and relay technology, we can improve the functionality of the total line protection system.

By ensuring that the protection equipment on both ends of a transmission line are optimized for efficient, fast, and safe operations, IPL can improve the fault clearing capabilities of its transmission equipment. Faults that are cleared faster from transmission lines reduce equipment damage and increase the system reliability and performance seen by our customers. IPL looks at the protection of a transmission line as a system which includes all equipment at both ends of the line. It is IPL's standard practice to upgrade line protection equipment at both ends of a transmission line simultaneously.

6.9.2 TDSIC Purposes

This Remote End – Breaker Relay/Upgrades Project meets TDSIC purposes in several ways. Replacing older circuit breaker technology and electromechanical relays with newer circuit breaker technology and microprocessor relays helps modernize IPL's electricity delivery system and provides operational performance improvements. This enhanced operational performance results in more efficient operations with fewer maintenance cycles. The completion of this Project will improve the operation and reliability of the IPL transmission system.

6.9.3 Description of Physical Improvements

At each substation location listed below a circuit breaker, relay or both circuit breaker and relay will be upgraded.

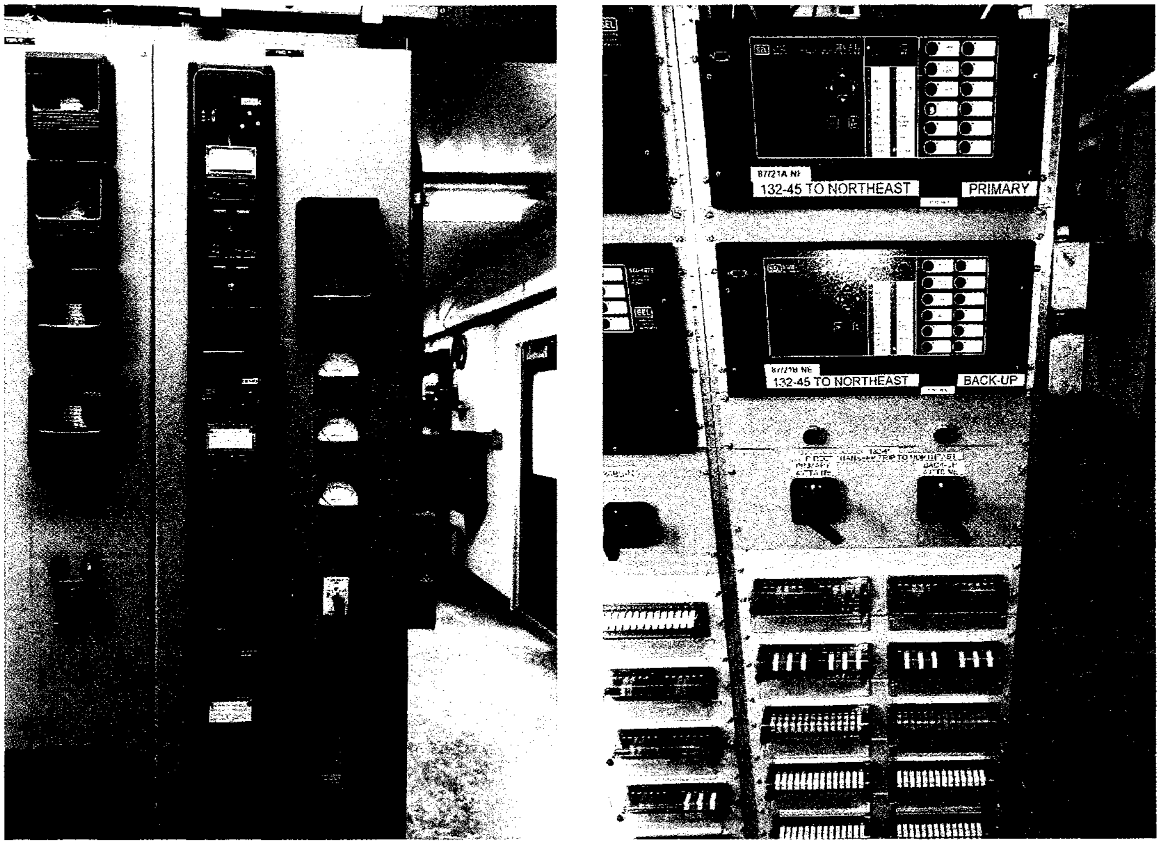
Table 6.9.2 – Locations and Types of Upgrades

Year	TDSIC Project	Type
2020	CASTLETON-132-54 BKR	Relay
2020	CASTLETON-132-55 BKR	Relay
2020	MILL STREET-132-65 LINE BKR.	Relay
2020	SUNNYSIDE-132-46 BKR	Relay
2020	SANITATION BLMT-138 BUSTIE OCB	Breaker
2020	ROCKVILLE-132-64 BKR	Breaker
2020	GLENS VALLEY-BUS TIE BKR	Breaker
2021	LILLY-SOUTH-132-61 BKR	Relay
2021	LILLY CORP-2451-1 BKR	Relay
2021	ENGLISH AVE-2471-1 BREAKER	Relay
2021	STOUT SOUTH YARD	Relay
2021	I.C.E.-BUS TIE BREAKER	Relay
2021	CRESTVIEW-138KV BUS TIE BKR	Breaker & Relay
2021	WEST-132-70W BKR	Relay
2021	WEST-132-63 BKR	Relay

2022	GLENS VALLEY-BUS TIE BKR	Relay
2022	IU CAMPUS N-3331-1 BKR	Relay
2022	LAWRENCE-132-48 BREAKER	Breaker
2022	STOUT N-132-14 WEST OCB	Breaker
2022	STOUT N-132-14 EAST OCB	Breaker & Relay
2022	MILL STREET-132-65 LINE BKR.	Breaker
2022	STOUT N-138-99 EAST OCB	Breaker & Relay
2022	STOUT N-138-99 WEST OCB	Breaker
2023	METHODIST HOSPITAL-3131-1 BKR	Relay
2023	ALLISON #3-451-1 BREAKER	Breaker
2023	SUNNYSIDE-132-46 BKR	Breaker
2024	NORTH-132-71-86 TIE BKR (7)	Relay
2024	CRESTVIEW-138KV BUS TIE BKR	Relay
2024	SANITATION BLMT-138 BUSTIE OCB	Relay
2024	CASTLETON-132-66 BKR	Relay
2024	LAWRENCE-132-45 BREAKER	Relay
2024	ST GT YD-132-02 BKR	Relay
2024	IU CAMPUS N-437-1 BKR	Relay
2024	PERRY K-34.5KV 2839-1 BKR	Relay
2024	IU CAMPUS W-391-1 BKR	Relay
2024	BROOKWOOD-1571-5 BKR	Breaker & Relay
2024	BROOKWOOD-132-36 BKR	Breaker
2024	NORTHWEST-132-04 BKR	Breaker & Relay
2024	NORTHWEST-132-39 BKR	Breaker & Relay
2025	CRAWFORDSVILLE RD.-132-35 BKR	Relay
2025	WILLIAMS ST-132-75 BREAKER	Relay
2025	LILLY CORP-4151-3 BKR	Relay
2025	NAVAL AVIONICS-1771-1	Breaker & Relay
2025	MAYWOOD-132-13 BREAKER	Breaker
2025	MAYWOOD-132-11 BREAKER	Breaker
2026	SOUTHEAST-132-72 BKR	Relay
2026	SOUTHEAST-132-18 BKR	Relay
2026	PROSPECT-1751-1 BREAKER	Breaker
2026	IU CAMPUS N-491-3 BKR	Relay
2026	IU CAMPUS W-431-3 BKR	Relay
2026	EAST-132-07 W BKR	Breaker
2026	WEST-132-70W BKR	Breaker
2026	WEST-132-06 BKR	Breaker & Relay

2026	WEST-132-63 BKR	Breaker
2026	EAST-132-07 E BKR	Breaker & Relay

Figure 6.9.3 – Before (left) and After (right) View of Circuit Breaker and Relay Upgrade



6.9.4 Benefits

The Remote End – Breaker Relay/Upgrades Project provides benefits for the IPL system Bulk Electric System in the following ways:

Improved Fault Clearing Times

The transmission line protective equipment forms a critical protective system. To optimize performance of the system, protection equipment on all ends of a transmission line need to have the same capabilities. With modern breaker and relay protection equipment, faults are removed from the electric system faster than with existing technology. This means that the damaging effects of fault currents flowing through the system are reduced, in turn extending the life of utility assets.

Further System Risk Reduction

While the primary goal of upgrading circuit breakers and relays is to improve the performance of the transmission protective system, when we replace additional equipment we are further reducing risk. By executing these projects in a coordinated manner at both ends of a transmission line simultaneously, IPL can efficiently upgrade each line section, while reducing the number of lines being taken out of service. This has value to our customers since all equipment outages pose a risk of degraded service.

Higher Fault Current Interrupting Capabilities

Additional DER on the IPL system increase available fault currents. Solar, wind, battery storage, and synchronous machines all contribute additional fault current. The breaker and relay upgrades help limit any issue IPL has with accommodating these new sources today and the expected increase in DER in the future.

Customer Benefits

The completion of this Project will improve the IPL transmission system operation and reliability. Customer operations and equipment, such as motors, can shut down because of voltage dips on the Bulk Electric System. This can be a significant cost for large C&I customers. This Project will help reduce the likelihood of customer impacts from faults by removing faults from the system faster.

Reduced Maintenance Cycles

The new modern substation equipment has longer durations between maintenance cycles relative to the existing equipment.

6.9.5 Summary

IPL's Remote End – Breaker Relay/Upgrades Project will reduce system disturbances providing better customer power quality and improving the operational performance of IPL's transmission system along with mitigating or avoiding maintenance cost increases.

6.10 Pole Replacements

Table 6.10.1 – Pole Replacements Project Overview

Project Attribute	Description
TDSIC Activity	IPL will replace approximately 330 wood poles annually based on inspection results of a ground line inspection and treatment program. This equates to 2,310 wood poles being replaced in the IPL TDSIC Plan.
Project Costs[30]	$24.2 million -- capital expenditure.

6.10.1 Background

Wood poles are essential infrastructure and a large asset base, by which electric utilities deliver energy to their customers. Utility best practices for maintaining wood poles include a ground line inspection and treatment program. IPL uses a ground line inspection and treatment program for its wood pole assets. IPL's entire wood pole fleet is inspected on a ten-year cycle. The inspections identify:

1.) ground line pole decay
2.) above ground pole decay
3.) pole top damage
4.) defects that may affect the integrity of the pole

Visual inspection of the pole at the ground line is critical because this is the most likely failure point. Freezing and thawing, the persistent presence of moisture and the ability for insect damage are the main reasons poles deteriorate at the ground line. During the inspection the pole is sounded with a hammer to detect decay. Based on the sound test the pole may be drilled to further evaluate the pole. In some cases, soil is removed to inspect the pole below grade to further inspect the pole for decay. Other common defects are poles splitting, wood pecker holes and unreported damage to the pole.

There are approximately 165,000 wood poles on the IPL system. IPL inspects approximately, 16,500 annually. IPL has a wood pole failure rate of 2.0%. Poles fail inspection in two categories. The first category is a "non-priority reject" inspection failure. These poles fail inspection criteria but do not need immediate attention. Non-Priority Reject poles are scheduled for replacement no later than the year following the failing inspection. The second category is a "Priority Reject" inspection failure. These poles fail inspection criteria with an elevated failure score. Priority poles

[30] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

are targeted for replacement within 30 days of failing inspection. Poles that pass the inspection are treated to prevent decay and further extend the life of the pole 10 years.

6.10.2 TDSIC Purposes

This Pole Replacements Project meets TDSIC purposes in two distinct ways. Replacing deteriorated poles improves public and employee safety in addition to maintaining system reliability.

6.10.3 Description of Physical Improvements

As discussed above, IPL has an inspection process whereby wood poles are inspected and tested above and below ground line and then replaced as necessary. Based on this inspection process, IPL will replace approximately 330 wood poles annually for a total of approximately 2,310 wood poles over the seven-year plan period. This inspection, recommended replacement, and number of replacements will be tracked for each year.[31] The IPL service territory is broken into 10 pole inspection areas.

6.10.4 Benefits

Benefits associated with the Pole Replacements Project are:

Safety

Replacing deteriorated poles improves public and employee safety. Failure of wood poles endangers the public by allowing energized conductors to fall below required clearances. Deteriorated poles also pose a danger to linemen who are required to climb poles to maintain and operate the electric system. Additionally, replacing deteriorated poles during emergency events generally involves adverse weather conditions, higher labor costs and the greatest number of customers without power. In contrast, replacing a deteriorated pole during normal work conditions can be accomplished more efficiently and cost-effectively and generally without taking customers out of service.

Harden the Electric System

Externally, a wood pole may appear to be in good condition but may have deteriorated internally and/or below the ground line to the point where the pole is no longer sufficiently strong enough to withstand horizontal loads produced by wind, or vertical loads caused by ice. Maintaining the integrity of the system's wood poles enables the electric system to better withstand the forces exerted on it by nature. Replacing poles under emergency conditions, such as during a storm event, can be significantly more expensive than during normal operating conditions.

[31] Technical specifications for inspection, groundline treatment and reinforcement of in-place poles, US Asset Management, Technical Specification #USSBU-10002-TD.

Add Resiliency to the Electric System

Maintaining the integrity of the wood poles reduces pole failure. This, in turn, better positions the electric system to bounce back from inclement weather events. Although the presence of failed poles may not necessarily impact the number of customers who lose power during a storm event, failed poles have a large impact on the duration and the cost of the restoration effort.

Risk Reduction

A systematic pole inspection and replacement project whereby deteriorated wood poles are removed and replaced reduces the overall risk of operating and maintaining the electric system.

6.10.5 Summary

The Pole Replacements Project is an accepted industry best practice that will maintain the integrity of the electric system along with safeguarding overall public and employee safety.

6.11 Steel Tower Life Extension

Table 6.11.1 – Steel Tower Life Extension Project Overview

Project Attribute	Description
TDSIC Activity	IPL will excavate and apply an anticorrosion protective coating to approximately 670 direct-buried steel transmission structures over a four-year period beginning in 2020. Many of these existing structures are rapidly approaching the end of their design lives and represent a potentially serious risk if left untreated. The life-extending coating proposed to be applied is a technological advancement in protective coating technology designed to extend the towers' useful life by up to 20 years.
Project Costs[32]	$4.2 million – capital expenditure

6.11.1 Background

IPL has approximately 3,500 steel transmission structures (both poles and lattice towers) carrying various circuits of its 866 miles of 138,000 and 345,000 Volt (138 kV and 345 kV respectively) electric transmission lines. Most of these structures are supported upon reinforced concrete foundations. However, approximately 670 structures are supported upon bare, galvanized steel buried directly in the earth. Most of these 670 structures were installed in 1932 (365 - 138 kV towers) and in the 1950's (204 - 138 kV towers). This Project supports ongoing safety and reliability as these structures age.

There are essentially two courses to address the direct-buried steel transmission structures -- replace the assets or utilize modern technology to extend their lives. There is an increasing risk of structure failure due to corrosion of the direct-buried steel. Corrosion is the result of an electrochemical reaction of a metal within its environment whereby the metal reverts to its original base elements. To date, corrosion of the direct-buried steel has been maintained by protective galvanized coating, but this coating has reached its end of life and needs refurbished.

Replacing the assets is costly and unnecessary. Instead, IPL will utilize modern steel coating technology to extend the life of these assets by approximately 20 years for an estimated cost of $4.2 million. Ideally, this Project may be repeated in 20 years for another 20-year life extension assuming all other aspects of the structures remain viable.

[32] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

6.11.2 TDSIC Purposes

This Steel Tower Life Extension Project meets TDSIC purposes in two key ways. First, the Project proactively addresses potential public safety concerns. When the 1932 vintage structures were initially installed, they were located primarily in very rural areas inside of Marion County. After years of development, things are considerably different today; these structures are located in now tightly-congested, urban environments. Proactively addressing potential structure failures safeguards the public and employees.

Second, the Project will proactively improve the IPL transmission system operation and reliability. While not currently experiencing unplanned outages due to structure failures, without this Project the likelihood of structures failing increases

The Project will provide valuable information on the condition of IPL's direct-buried steel assets that will enable IPL to better manage and control future capital and operational costs. A planned, proactive approach is a much more efficient maintenance approach than reactive emergency repairs.

6.11.3 Description of Physical Improvements

IPL will excavate around each leg of identified, direct-buried steel structures to a depth of up to 24 inches, clean the steel, apply a technically-advanced protective polymer coating, refill the hole with the previously-excavated soil, and restore any property damaged during the process.

Figure 6.11.1 – Before/After Photos of a Typical Direct-Buried Steel Tower Leg

Due to the properties of the proposed coating, this work can only be performed under moderately warm conditions. IPL proposes to treat every direct-buried steel structure starting in Spring 2020 and continuing for four seasons, ending in the Fall of 2023.

Table 6.11.2 – Schedule

YEAR	ACTION
2020	183 Structures Treated
2021	182 Structures Treated
2022	170 Structures Treated
2023	133 Structures Treated
Total	668 Structures Treated

6.11.4 Benefits

IPL's Steel Tower Life Extension Project benefits the IPL system and IPL's customers, including the following:

- IPL will extend the life of assets at a nominal cost compared to asset replacement.
- IPL will mitigate the risk of failure of transmission structures due to below-grade corrosion.
- This Project will mitigate public and employee safety risk.
- IPL will mitigate the risk of unplanned transmission outages due to structure failures.
- IPL will mitigate the risk of unplanned or emergency maintenance.
- IPL will be able to better manage and control capital and O&M costs through valuable data that can be used for more robust asset management.
- By mitigating risk of structure failure and outage, this Project will improve system reliability and mitigate risk and duration of customer outages.

6.11.5 Summary

In summary, the Steel Tower Life Extension Project prudently addresses important infrastructure which may reasonably be expected to experience increasing reliability and operational issues if left to deteriorate. This Steel Tower Life Extension Project provides system and customer benefits such as reduced safety and structure risk.

6.12 Distribution Automation

Table 6.12.1 – Distribution Automation Project Overview

Project Attribute	Description
TDSIC Activity	IPL will install 1,200 new distribution line reclosers and a new central control system to increase system automation; to improve distribution system operation and reliability; to enable voltage management and associated energy conservation; and to facilitate interconnection with distributed energy resources and new loads.
Project Costs[33]	$109.0 million - capital expenditure

6.12.1 Background

IPL currently uses three control systems to help manage distribution operations. The three control systems are the Radio-Controlled Capacitor System (RCCS), the Distribution Supervisory Control & Data Acquisition (DSCADA) and the Outage Management System (OMS). RCCS is a basic power factor control system that maintains power factor at the substation level. DSCADA gathers status data and controls devices. OMS helps manage customer outages. These systems lack integration and all three systems are nearing obsolescence.

As of December 31, 2018, IPL has installed nearly 300 reclosers on distribution poles to improve reliability by isolating trouble on distribution lines to smaller sections. The use of reclosers increases circuit sectionalization, and this reduces the number of customers who experience an outage when a fault occurs. This technology also gives system operators opportunities to remotely control service restoration. IPL's experience with the existing reclosers along with analysis of modern control system capabilities indicate the IPL distribution system and IPL's customers will benefit from 1200 additional reclosers and modern central controls.

Technological limitations in the existing control systems and lack of real time data causes uncertainty about the actual voltage delivered to customers. As a result, IPL (and the industry generally) has traditionally kept substation voltages on the higher end of the allowable range. This practice assures customers located at the end of the distribution lines have adequate voltage. IPL (and the utility industry generally) knows that lower voltages within allowable ranges help customer equipment use less energy. IPL's existing capacitor control system, RCCS, is not designed to deliver integrated Volt/var control (and associated energy savings) to customers.

[33] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

IPL's experience with temporary demand reduction together with industry knowledge confirm that a modern control system can deliver energy savings and distribution system benefits. These benefits will be enabled by voltage sensors associated with the proposed reclosers and the modern distribution control system discussed above. This modernized infrastructure is estimated to reduce customer energy consumption by 1%, saving (about 112,000 MWh per year).

Finally, the electric distribution system is transforming from a traditional radial power flow to a bi-directional power flow grid. More specifically, electric vehicles, solar, wind and battery storage systems connected to the grid are changing how IPL operates and maintains the system.

IPL has significant experience integrating large solar projects into the distribution system. IPL's experience confirms that distributed resources can introduce safety, reliability and power quality concerns on the distribution system. The complexity of these concerns grows with each new site and as more localized distributed resources are added to the system. The proposed modernization of IPL's distribution control system is necessary to facilitate the ongoing interconnection with these types of resources.

6.12.2 TDSIC Purposes

The Distribution Automation Project adds distribution infrastructure and replaces older control systems with modern control systems that will increase automation, improve distribution infrastructure safety, operation and reliability, facilitate outage management and service restoration; enable voltage control and associated energy conservation; and improve interconnection with distributed resources.

Reliability improvements are achieved by strategically placing 1,200 new reclosers on distribution circuits. These reclosers can better detect, locate and isolate problems on the distribution system. Repair crews can be more accurately directed to the source of trouble. Improved location detection and associated faster crew arrival times enhance public and employee safety. A modern control system improves reliability with Fault Location, Isolation, and Service Restoration (FLISR) functionality. The FLISR functionality is estimated to eliminate, on average, 23,000 customer interruptions per year. It is also expected to reduce the duration of approximately 167,000 interruptions per year to less than 5 minutes. The Department of Energy Interruption Cost Estimate ("DOE ICE"), a widely accepted benefits calculator, indicates IPL customers will realize about $21 million of value per year when the project is completed.

Modernizing the control system and leveraging the existing capacitor controls will enable voltage management and associated energy conservation. The voltage sensors associated with the proposed reclosers eliminates the need for independent sensors on the system. The Distribution Automation Project is estimated to will reduce customer energy consumption by 1%, saving about 112,000 MWh per year.

The new central control system replaces three different infrastructures with a single integrated system. All three of the legacy systems have different operator interfaces and different interfaces to essential circuit models. The new system streamlines the interface to models and gives system operators much better situational awareness with integrated displays.

The Distribution Automation Project is undertaken for purposes of safety, reliability and system modernization while providing benefits to IPL customers and facilitating economic development.

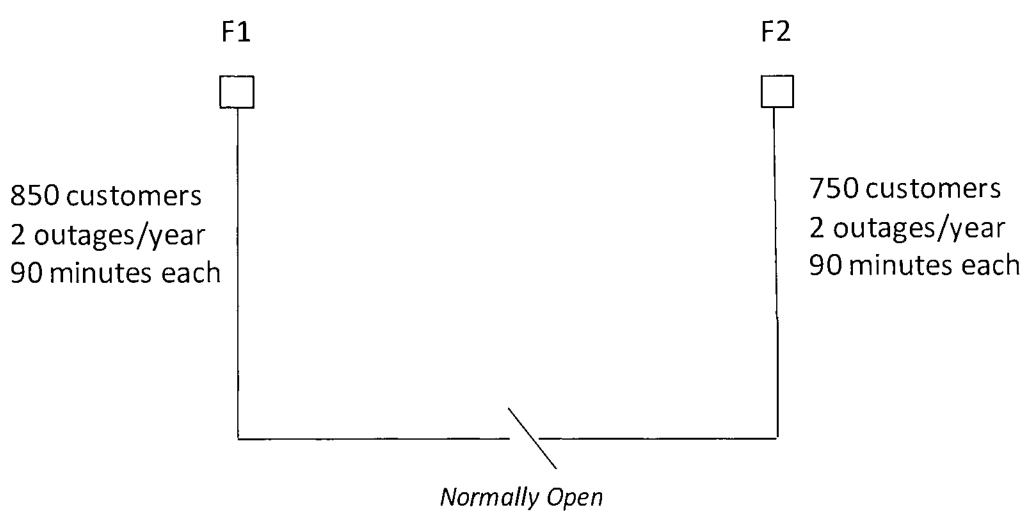
6.12.3 Description of Physical Improvements

IPL will procure, program and install 1,200-line reclosers on distribution poles located throughout the IPL service territory. The reclosers will be deployed equally over the seven-year TDSIC Plan period. The reclosers will be strategically positioned to create sections with about 400 customers in each section. These reclosers will have two-way remote communication. They will have autonomous and remote-control capability. The reclosers will also have accurate voltage and current sensors on each of the three phases to facilitate Volt/var control described below.

Fault Location, Isolation, and Service Restoration (FLISR)

Figures 6.12.1 and 6.12.2 below show a simple, hypothetical example to illustrate customer outage experience before and after installing reclosers with Distribution Automation FLISR. The initiating events in Figures 6.12.1 and 6.12.2 are identical but the customer experience materially improves with FLISR.

Figure 6.12.1 - Customer experience before Distribution Automation



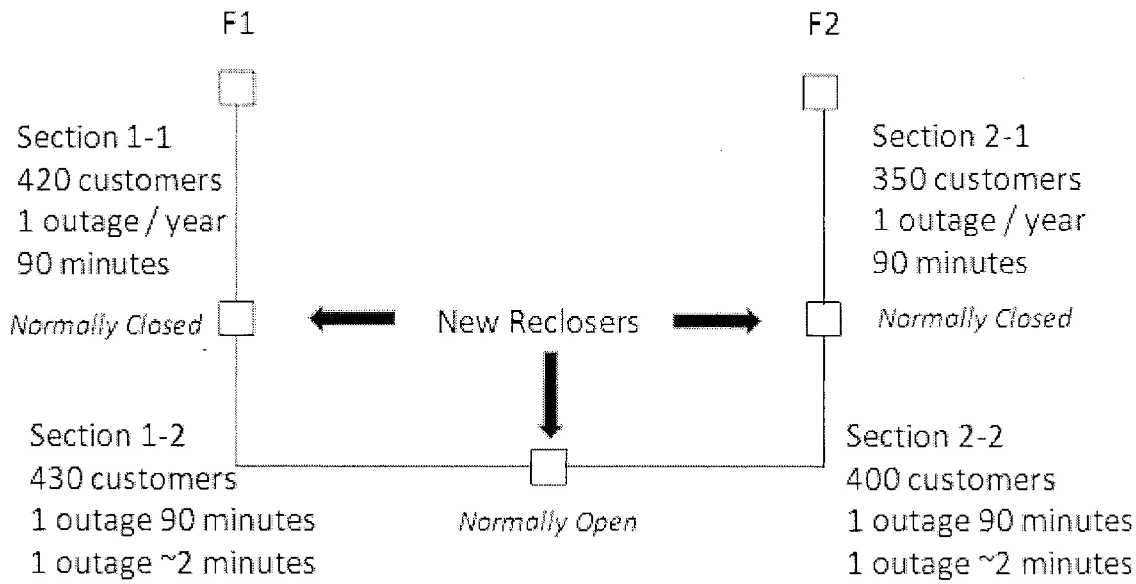
Trouble Anywhere on F1 Section

The 850 customers served from Feeder 1 (F1) will experience a total of 2 ninety-minute outages

Trouble Anywhere on F2 Section

The 750 customers served from Feeder 2 (F2) will experience a total of 2 ninety-minute outages

Figure 6.12.2 - Customer experience after Distribution Automation



Trouble on Sections 1-2 or 2-2

Figure 6.12.2 shows the improvement after reclosers are installed. Customers on Sections 1-1 and 2-1 see one less outage per year because the normally closed reclosers open automatically for any trouble on Sections 1-2 or 2-2. Customers on Sections 1-2 and 2-2 will still experience a sustained outage for trouble in their section. However, repair crews have much better information about the trouble location which helps shorten repair times.

Trouble on Sections 1-1 or 2-1

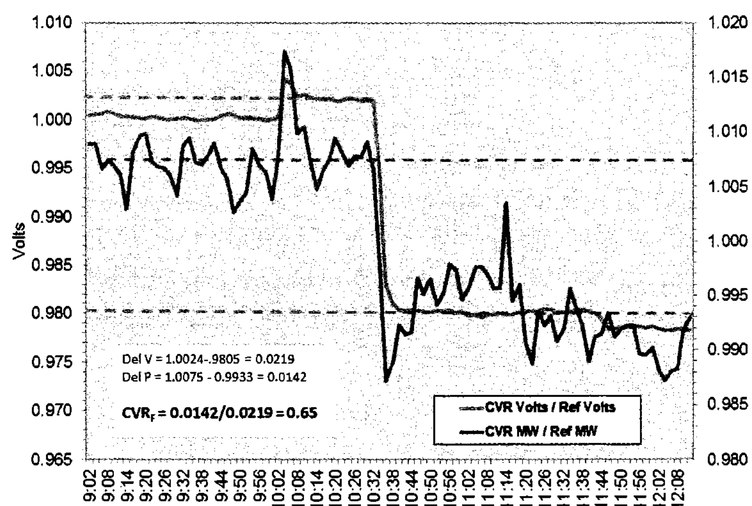
Customers on Sections 1-2 and 2-2 also experience outages for trouble on Sections 1-1 and 2-1 before distribution automation. However, when Distribution Automation performs FLISR, service is automatically restored by alternate supply. After FLISR is deployed customers in sections 1-1 and 2-1 still experience sustained outages while customers in section 1-2 and 2-2 only experience a brief outage for trouble on sections 1-1 or 2-1.

Integrated Volt/var Control (IVVC)

The new central distribution control system will include modern IVVC capability. This will replace the outdated capacitor control system. IVVC will optimize distribution voltages to achieve energy savings for IPL customers. IVVC can provide additional visibility and operational flexibility in responding to system conditions. The IVVC Project will use load and voltage data from the new and existing reclosers, substation equipment and existing capacitors. It will take that data, perform optimization calculations and send control signals to capacitors and substation voltage regulation equipment.

Figure 6.12.3 shows results of a test IPL performed to accurately measure load response to voltage. The test treated about half of the load with a voltage reduction. The other half was left untreated for a baseline. Figure 6.12.3 shows how the treated voltage was lowered 0.0219 per unit (2.19%) compared to the reference baseline. The treated load dropped 0.0142 (1.42%) compared to the reference baseline. This calculates a Conservation Voltage Reduction (CVR) factor equal to 0.65. In general, a 1% voltage reduction will yield 0.65% reduction in energy consumption.

Figure 6.12.3 – Test for conservation voltage reduction



Once the Distribution Automation control system is operational, IPL will lower the average system voltage by 2% on the 13.2 kV distribution feeders. CVR will be applied to all distribution circuits from 90 distribution substation transformers. This represents a historical peak load of 2,000 MW which is roughly 75% of IPL's system peak demand. (CVR is not practical for IPL's transmission and sub-transmission systems.) IPL will make a conservative assumption of CVR factor equal to 0.5 for future loads. This yields a conservative 1% energy savings over the life of the project.

IPL will replace a rudimentary distribution DSCADA with the new central computer control system. This will provide operators with much greater situational awareness and flexibility for complex operations.

IPL will also incorporate a legacy OMS as part of the new master distribution control system. The existing OMS has been adequate but there are no indications that it will be upgraded to include FLISR or IVVC necessary to achieve the needed reliability and conservation benefits.

6.12.4 Benefits

IPL's Distribution Automation Project offers a variety of benefits to the distribution system and IPL customers. The Project improves reliability, enhances safety and provides voltage management and associated energy conservation. Additionally, modern infrastructure facilitates economic development. The Distribution Automation Project also prepares the distribution system for the ongoing development of distributed energy resources and loads. Project benefits are further described below:

Safety

The Distribution Automation Project enhances safety in many ways. Repair crews have more accurate information about the location of trouble. This helps them arrive earlier and make areas safe sooner. Critical infrastructure such as fire stations, traffic lights, sewage lift, health care, and life support see fewer outages and remaining outages are often have a much shorter duration.

Customer Reliability Improvement

The reclosers and Distribution Automation will perform FLISR. This system will eliminate about 23,000 customer interruptions per year and substantially shorten the duration of about 167,000 interruptions.

Customer Energy Savings

Distribution Automation will use the new reclosers along with the new control system and other existing equipment to perform IVVC. The conservative estimated CVR factor described earlier will reduce average energy consumption by 1% per year. This reduces energy consumption and by at least 112,000 MWh per year.

Distributed Resources and New Loads

New distributed resources and loads place additional challenges to the distribution system. IPL has considerable experience with distributed resources as a result of IPL's Renewable Energy Production tariff, which made Indianapolis a leader in solar development. These distributed resources have occasionally caused excess voltage, improper fault isolation, higher short circuit currents, and possible back feed. Residential loads attempting solar net zero energy create reverse peak demands two to three times the original forward demand. This reverse demand could overload supply equipment. The Distribution Automation Project will help make these issues and other issues visible to IPL operations and provide more capability to deal with them.

Improved Distribution Control Capabilities

The Distribution Automation Project overcomes obsolescence concerns of three disparate control systems in service today. The existing distribution DSCADA does not provide adequate operational awareness. The RCCS does not and will not perform IVVC for the necessary energy savings. The outage management system is unlikely to ever incorporate DSCADA, IVVC, and FLISR into a single package. The Distribution Automation Project brings all these functions together. It substantially reduces the cost of building software interfaces between disparate systems. It substantially improves operational awareness and efficiency of the distribution system.

6.12.5 Summary

IPL's Distribution Automation Project increases circuit sectionalization and provides a modern control system to automate and modernize the distribution system while also providing benefits, such as voltage management that are not available through IPL's existing control systems and facilitating interconnection with distributed resources. The Distribution Automation Project enhances safety and reliability. The better reliability and acceptance of new loads enhances future economic development.

6.13 Substation Design Upgrades

Table 6.13.1 –Substation Design Upgrades Project Overview

Project Attribute	Description
TDSIC Activity	IPL will reconfigure and/or add capacity at six existing substations and construct two new substations for additional distribution system capacity. These substation projects will improve load serving capability, operability, and reliability of the electric system.
Project Costs[34]	$94.5 million -- capital expenditure

6.13.1 Background

IPL owns and maintains a large fleet of transmission and distribution substations located throughout its service territory. The substations are essential infrastructure for the safe and reliable delivery of electricity to IPL's customers. In the context of this project, improving deliverability of the IPL electric system has two components. First, reconfiguring or adding system elements enables the electric system to isolate faults (contingent events) without removing as many elements from service. This improves reliability to the electric system. Second, adding capacity, through larger current carrying equipment, enables the electric system to absorb the loss of system elements. This too improves the reliability of the electric system.

As part of the overall TDSIC initiative, IPL has focused attention broadly on the imperative of replacing high risk assets. The role of new functionality, such as Distribution Automation, focuses on ensuring that the IPL electric system is positioned to adequately serve load. The substation projects improve IPL's ability to deliver energy to customers in the following ways:

- Improve load serving capacity to support customer load growth.
- Lower the risk of customer outages during transmission and/or substation maintenance by improving the operability and maintainability of the system.
- Enhance transmission system performance, with respect to North American Electric Reliability Corporation (NERC) requirements, by creating a more reliable substation design to address contingencies.
- Reduce congestion caused by the need for system redispatch on the BES.

[34] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

Table 6.13.2 provides a summary of these objectives mapped to each of the substation projects, noting benefits.

Table 6.13.2 –Substation Design Upgrades Objectives

Project (Substation)	Improve Load Serving Capability	Improve Operability related to NERC Performance Requirements	Bring Substation to Current Design Standards	Reduce Outage Risks and Improve Operational Flexibility
Mooresville	X		X	X
Guion		X		
Rockville		X		
Stout		X		
Center			X	X
Prospect			X	X
New- Sub 2023	X			
New- Sub 2025	X			
Drop-In Control Houses				X

6.13.2 TDSIC Purposes

The Substation Design Upgrades Project meets TDSIC purposes in following ways:

- By modifying substation configurations, through ring bus configuration and other means, IPL will improve the operability and reliability of the IPL transmission and distribution system.
- Certain substation modifications improve operability and reliability by removing operating guides otherwise required to meet NERC transmission system planning performance requirements. These projects improve the BES by increasing system import limits and operational flexibility, lowering congestion caused by the need for system redispatch, and addressing risks posed by contingency events.
- Modifying the topology of substations allows IPL to reduce exposure to outages while performing maintenance on the system. Reduced exposure is accomplished by taking smaller sections of the system out of service to perform routine maintenance on equipment. These improvements will modernize the IPL system and increase its overall reliability.

- The Substation Design Upgrades project will add distribution capacity to the system that can be used to support economic development initiatives in the Indianapolis metropolitan area.

6.13.3 Description of Physical Improvements

Below are descriptions of the Substation Design Upgrades projects:

1.) **Mooresville Substation** -- IPL will replace two power transformers increasing the capacity of the distribution system. IPL will also install two new 138 kV breakers and reconfigure the 138-kV bus to form a ring bus. The project also includes modern relay packages and associated equipment.

2.) **Guion Substation** -- The Guion Substation project removes the risk of potential overloads under certain contingency events. Thermal ratings of equipment are exceeded for certain outage contingencies and IPL relies upon operating guides to reconfigure the system to meet the transmission system planning performance requirements of TPL-001-4. To address this, IPL will add a 345/138 kV transformer and modify the existing substation configuration to include a 345 kV ring bus. This requires three new 345 kV breakers and two new 138 kV breakers.[35]

3.) **Rockville Substation** -- The Rockville Substation project removes the risk of potential overloads under certain contingency events. Thermal ratings of equipment are exceeded for certain outage contingencies and IPL relies upon operating guides to reconfigure the system to meet the transmission system planning performance requirements of TPL-001-4. To mitigate this, IPL will install a new 345 kV breaker at the Rockville Substation to create a ring bus configuration.

4.) **Stout Substation** -- The Stout Substation project removes the risk of potential overloads under certain contingency events. Thermal ratings of equipment are exceeded for certain outage contingencies and IPL relies upon operating guides to reconfigure the system to meet the transmission system planning performance requirements of TPL-001-4. To mitigate this, IPL will install a new 345 kV breaker at the Stout Substation to create a ring bus configuration.

5.) **Center Substation** -- The Center Substation project updates the substation to modern construction and design standards, which will improve worker safety and IPL's operational flexibility. IPL will add a total of three new 138 kV breakers and replace three existing 138 kV breakers. One of the new breakers will be a line breaker and the other two will be transformer breakers. These breakers provide the ability to isolate faults

[35] For the thermal exceedances described in the Guion, Rockville, and Stout substation projects, IPL is in full compliance with NERC TPL-001-4 requirements. The improvements described here offer a superior means of transmission system performance and confer other benefits to both the BES and IPL customers.

(contingent events) without removing as many elements from service. This equipment allows IPL to reconfigure the bus arrangement in the substation. IPL will also replace an existing 34.5 kV capacitor with an enclosed capacitor that includes a pre-insertion resistor.

6.) **Prospect Substation** -- The Prospect Substation project increases IPL's system reliability and operational flexibility. IPL will add one new 138 kV line breaker. The principal goal of this modification is to provide isolation of two transformers from the 138-kV line. The current station arrangement includes common bus among both transformers and the transmission line, which requires distribution circuit outages to isolate the line for faults. The addition of the breaker allows for separate isolation and directly increases customer reliability.

7.) **New Substation 2023** – The Substation Design Upgrades Project includes a new 138/13.2 kV substation in 2023. The new substation is needed to convert the 4 kV system load to the 13.2 kV system. The project will include three 138 kV breakers, two 138/13.2 kV 40 MVA transformers, and all necessary associated switches and relay/protection equipment.

8.) **New Substation 2025** – The Substation Design Upgrades Project includes a new 138/13.2 kV substation in the IPL service area near the old southside. This area, which once served an industrial load, is now being revitalized and IPL needs facilities to serve the mixed-use load from the ongoing economic development of this area. This new substation is planned to be placed in service to meet service needs in 2025. The new distribution substation will also provide additional operational flexibility to serve load from other nearby substations. The project will include three 138 kV breakers, two 138/13.2 kV 40 MVA transformers, and all necessary associated switches and relay/protection equipment.

9.) **Drop-In Control Houses -** At substations where significant upgrades will take place, utilizing a drop-in control house reduces cost and adds efficiency and operational security to a substation upgrade project. A drop-in control house provides the ability for all protection and control equipment to be installed and tested at one time without complicated equipment outages. When yard equipment is replaced, cables are installed between the yard equipment and the new control house. This allows for the equipment to be returned to service faster with less risk of a human error or the need for extensive work in and around energized relay panels. Drop-in control houses will be utilized for three substation projects in IPL TDSIC Plan, Southwest Sub, Northwest Sub and Northeast Sub.

6.13.4 Benefits

There are several tangible benefits associated with the Substation Design Upgrades Project.

Improved Transmission Performance with Respect to NERC Compliance

Several substation improvements improve IPL's transmission system performance. This means that IPL operators will be able to more efficiently operate the transmission system for contingency events. The resulting conditions improve total system reliability and reduces risks. These changes, in turn, improve the BES operational flexibility and reliability, and decrease the dispatch of generators under certain conditions (reducing fuel and other operating costs). In some circumstances system import limits are improved. These changes also lead to reduced congestion, thereby lowering IPL's local zone locational marginal pricing (LMP) to which system participants are exposed.

Improve Distribution System Capacity & Capability

Several deliverability projects will improve IPL's distribution system capacity and capability. IPL will create permanently engineered solutions to serve load needs either through system expansion or substation rehabilitation. These capability improvements include increased load serving capacity and resiliency, economic development benefits throughout the IPL system, and superior mobile equipment implementation strategies. The substation improvements also give IPL the means to perform maintenance without forcing re-dispatch of the system, which mitigates congestion. Therefore, by creating greater operating flexibility, the overall system reliability is improved.

Improved Maintainability and Reduced Customer Outage Risks

By modifying the topology of the substations, IPL increases its operating flexibility. This improves IPL's ability to maintain the substations without creating outage risks for customers. This improves the IPL system reliability and reduces total system risk. Some of these benefits also accrue when bringing older substations up to current designs.

Enables Continued Economic Development

The Substation Design Upgrades Project positions the IPL electric system to enable the continued economic development the City of Indianapolis is experiencing. As the City of Indianapolis attracts new business and industry the Substation Design Upgrades Project will absorb the electric load that comes with them. These projects will allow IPL to continue to provide reliable and efficient delivery of energy to our existing and future customers.

6.13.5 Summary

The Substation Design Upgrades Project is a strong example of how reasonable, prudent engineering planning and design applied to changing system conditions can lead to many benefits, which ultimately accrue benefit to IPL's customers.

Moreover, these benefits are well aligned to TDSIC purposes and will result in a better delivery system for IPL and its customers, one that is safer, more reliable, and more resilient in the face of many potential system contingency events.

7 Plan Implementation

7.1 Implementing IPL's TDSIC Plan

The implementation of IPL's TDSIC Plan will be will be managed by a Project Management Organization (PMO). The PMO is responsible for each TDSIC Project's scope, cost and schedule. The PMO is charged with bringing accountability, visibility and repeatability to TDSIC project execution.

Accountability is accomplished by having the PMO own the implementation of the IPL TDSIC Plan. The PMO will work with internal and external partners to manage each Project using project management principles and tools. The PMO works in collaboration with Operations, Safety, Engineering, Environmental, Supply Chain, Accounting, Accounts Payable, Regulatory and other functional areas to create and execute Project plans. Project Managers will be responsible for Project plans and each Project life cycle step: initiate, plan, execute, monitor/control and close out.

Visibility into project health of the TDSIC Plan can be achieved by a variety of industry standard tools which provide a snapshot in time on the progress of individual projects. The PMO will compare the planned implementation schedules to the actual progress of projects to identify variances of cost, schedule and scope. These variances are tracked and acted upon to drive the actual cost, scope and schedule to the plan.

Repeatability will be accomplished through a PMO sponsored lesson's learned process. At the completion of a project the project team evaluates the variances to the plan and determines what corrective actions can be taken to mitigate future similar project variances. These lessons learned are then socialized with the broader project management team so that visibility into future projects can be obtained.

8 Appendices

8.1 Map of IPL Service Territory

8.2 Map of Indianapolis Central Business District

8.3 Burns & McDonnell Risk Model Report

8.4 Black & Veatch Review of the Burns & McDonnell Risk Model

8.5 IBRC's Economic Impact Assessment Report

8.6 Black & Veatch Cost Estimate Review and Validation Report

8.7 Cost Estimates, Year by Year Project Detail (Sortable List) and Plan Projects by FERC Account

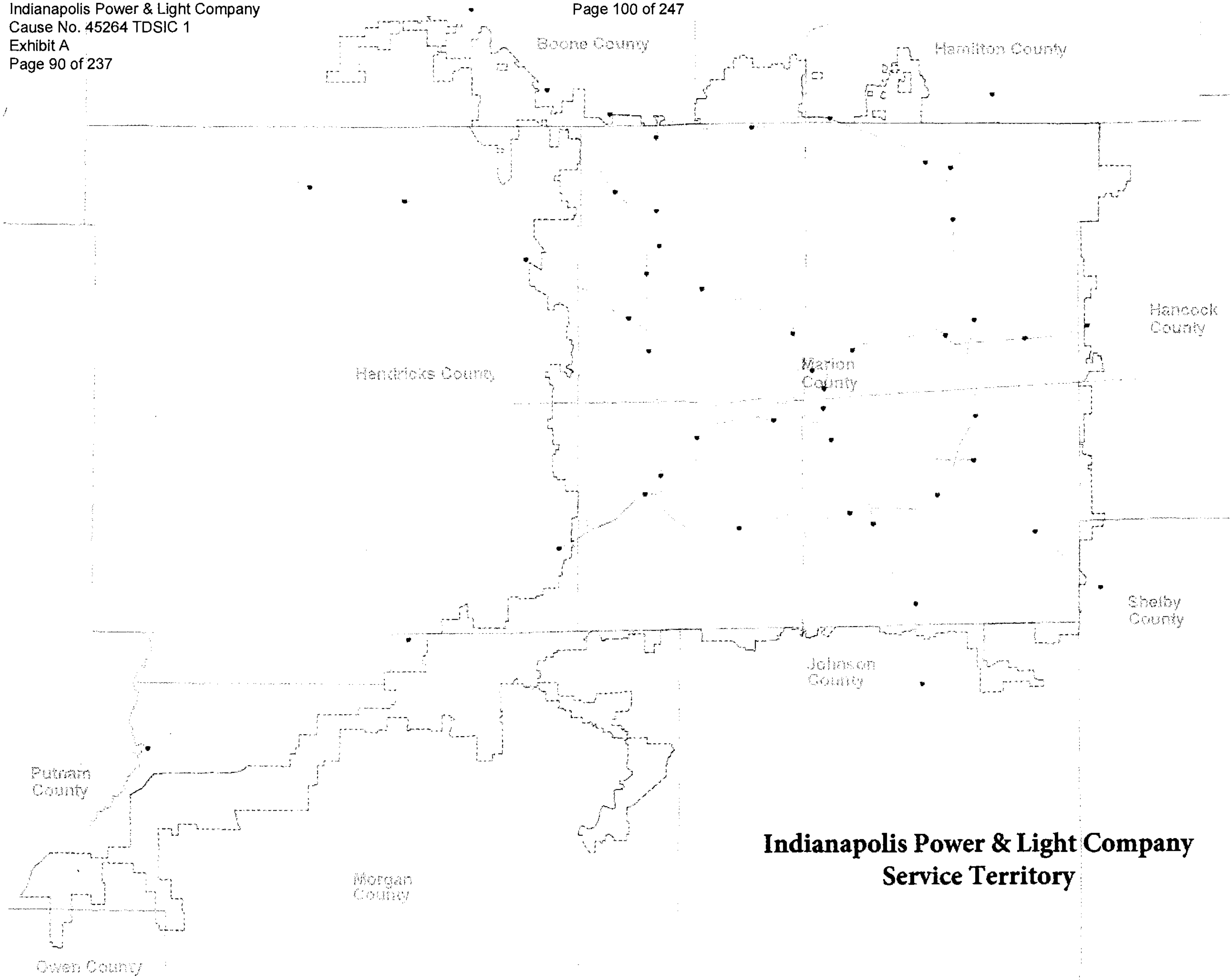
8.8 Class 2 Estimate Example

8.9 Class 3 Estimate Example

8.10 Class 4 Estimate Example

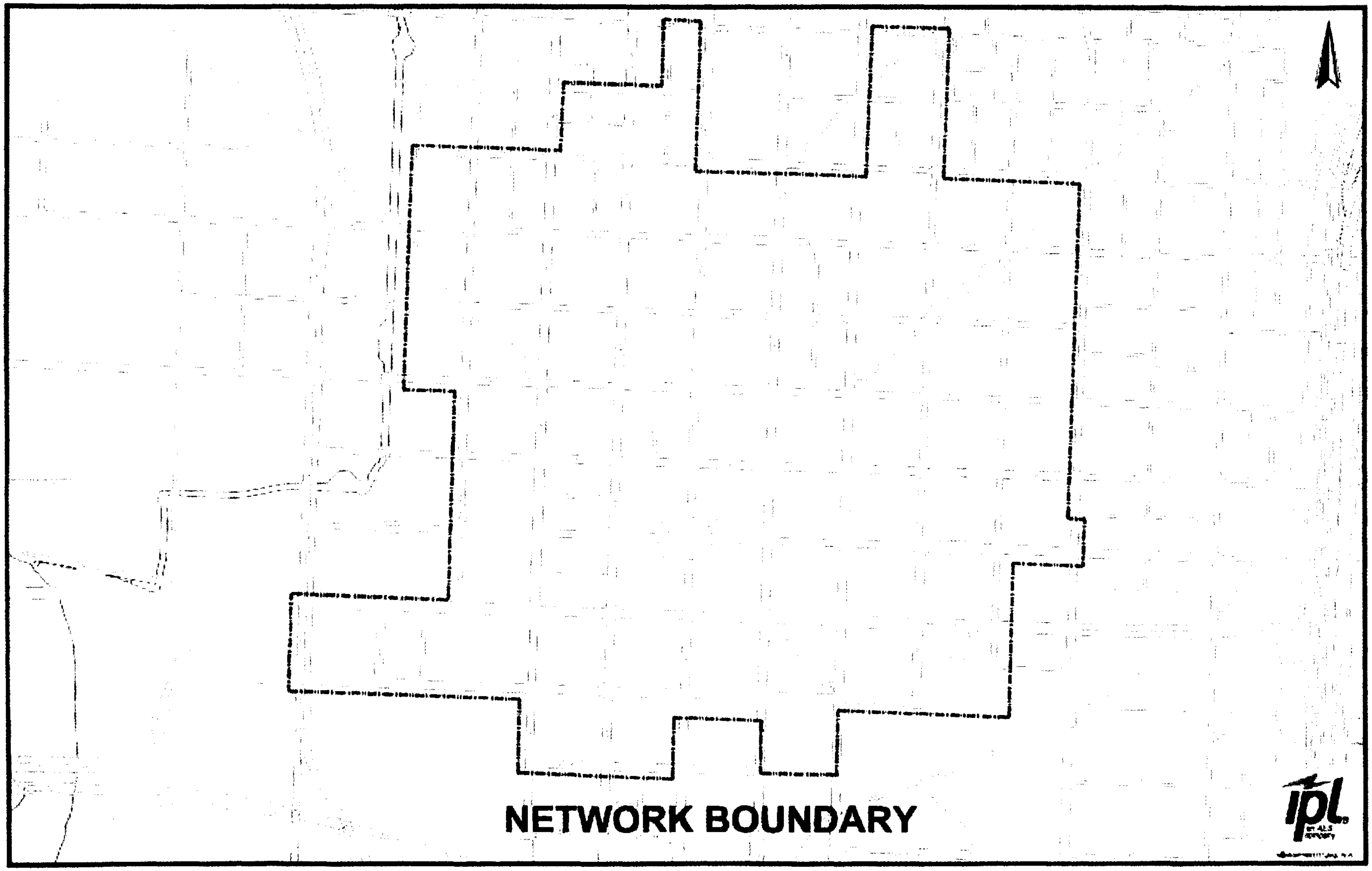
8.11 Risk Reduction Benefit Monetization Report

Appendix 8.1 Map of IPL Service Territory



Indianapolis Power & Light Company Service Territory

Appendix 8.2 Map of Indianapolis Central Business District


NETWORK BOUNDARY

Appendix 8.3 Burns & McDonnell Risk Model Report

Asset Risk & Investment Assessment Report

Indianapolis Power & Light Company

IPL TDSIC Asset Risk & Investment Assessment Report
Project No. 104713

Asset Risk & Investment Assessment Report

prepared for

Indianapolis Power & Light Company
IPL TDSIC Asset Risk & Investment Assessment Report
Indianapolis, Indiana

Project No. 104713

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
AHI	Asset Health Index
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
COF	Consequence of Failure
DGA	Dissolved Gas Analysis
GIS	Geospatial Information System
IPL	Indianapolis Power & Light Company
ISO	International Standards Organization
LOF	Likelihood of Failure
OH	Overhead
T&D	Transmission and Distribution
TDSIC	Transmission, Distribution and Storage System Improvement Charge

1.0 EXECUTIVE SUMMARY

IPL engaged the services of Burns & McDonnell in developing the TDSIC asset risk assessment and investment analysis. In collaboration, IPL and Burns & McDonnell utilized a risk-based planning approach to identify assets for replacement and prioritize investment in the T&D system. While risk-based planning approaches have many purposes, two key purposes for the Asset Risk Model are:

1. Identify high-risk assets and establish a plan to manage the risk.
2. Identify the highest risk reduction per dollar invested for the system.

While risk reduction is a significant benefit and the focus of this report, it is not the only benefit of IPL's TDSIC Plan. Additional benefits are described and quantified elsewhere in IPL's TDSIC Plan[1]. The Asset Risk Model follows best practice and includes the required elements to identify and prioritize assets for replacement. Risk-based prioritization facilitates the identification of the critical assets most likely to fail. Prioritizing and optimizing investments in the system helps ensure the ratepayers get the "biggest bang for the buck."

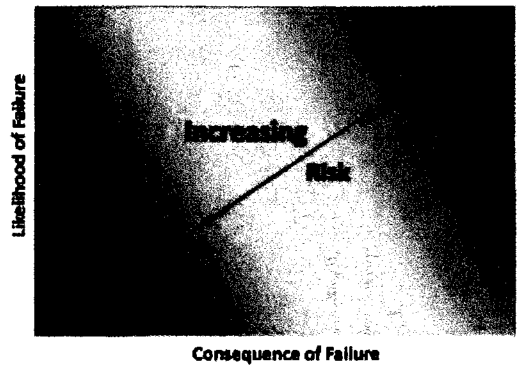
The Asset Risk Model utilizes survivor curves to calculate an assets likelihood of failure. When available, asset condition and health information is used to calculate an asset's 'effective' age. Asset health indices incorporating IPL's recent condition assessment information were calculated for power transformers, breakers, and wood poles, which comprise a significant portion of the asset base in the Asset Risk Model. Additionally, the Asset Risk Model incorporates asset criticality to calculate a consequence of failure score across a range of established criteria. The Asset Risk Model leverages much of the asset management approach reviewed with IPL stakeholders during a recent asset management collaborative effort.2 Using the elements described above, IPL and Burns & McDonnell evaluated three investment scenarios within the Asset Risk Model to inform the development of IPL's TDSIC Plan.

[1] See IPL TDSIC Plan Section 3 for discussion of Plan benefits.
[2] This collaborative was conducted per IURC Order in Cause No. 44576 dated March 16, 2016.

1.1 Risk Based Planning Approach

In alignment with best practice asset management and the International Standards Organization (ISO) definition of risk (ISO 31000), the Asset Risk Model defines risk for an asset as being the product of the likelihood of failure (LOF) and the consequence of failure (COF) or impact caused by the failure. Typically, risk results are visualized using a risk grid/matrix, or heat map. The upper right-hand corner zone demands special consideration and attention. An example risk grid is shown in Figure 1-1. Use of this methodology enables a better understanding of which assets pose the highest risk to the electric system and this in turn assists IPL in optimizing the portfolio of aging asset replacement.

Figure 1-1: Risk Matrix



Similarly, the Asset Risk Model adheres to best practice and ISO standards for risk management. The basic framework for the risk assessment follows the process below:

- Risk identification – the asset register, asset definition, and expected asset failure mode
- Risk assessment – consequence and likelihood frameworks including asset health
- Risk mitigation measure development – asset replacements and project bundling
- Risk mitigation measure implementation – executing the mitigation plan

The Asset Risk Model uses the process and approach outlined above for assessing risk. The adjacent table, Table 1-1, shows the LOF and COF risk grid framework utilized in the Asset Risk Model.

Table 1-1: Risk Framework

Score	LOF	COF
1	Remote	Very Low
2	Low	Low
3	Moderate	Moderate
4	High	High
5	Very High	Very High

1.2 Asset Risk Model Overview

The risk-based planning approach calculates risk at an asset level, creating an Asset Risk Model. The Asset Risk Model is a tool used in the development of IPL's TDSIC projects. The Asset Risk Model identifies high-risk assets using asset condition, survivor curves, and consequence of failure criteria for the T&D system and calculates the risk reduction benefit of replacing those assets. Specifically, the model quantifies the expected risk reduction of higher-risk assets over the 7-year TDSIC planning period from 2020 through 2026. The quantitative risk assessment provided by the Asset Risk Model provides transparency and logic to a replacement planning program.

Table 1-2 provides a summary of the assets and asset counts included in the Asset Risk Model.

Table 1-2: T&D Assets in Risk Model Summary

Asset Type	Units	Total
Breakers	Count	1,359
Power Transformers	Count	217
Batteries	Count	114
Transmission and Sub-Transmission	circuit miles	1,135
Overhead Primary Distribution	circuit miles	3,677
Underground Primary Distribution	circuit miles	3,977

1.3 'Do Nothing' Risk Results

The 'Do Nothing' scenario represents the increase in risk for the assets in the Asset Risk Model if no assets are replaced during the 7-Year planning period. This provides a baseline for comparing investment scenarios and their impact to IPL's system risk. This approach is appropriate because few utilities, including IPL, have a long-term (5 to 10 year) baseline for capital improvements with specific projects. 'Do Nothing' scenarios are routinely used to perform analysis such as that presented in this report.

Figure 1-2 and Figure 1-3 show the asset and circuit counts within the risk grid results of the 'Do Nothing' risk scenario in 2026 for substations and circuits, respectively. Section 4.0 provides additional analysis, results, and context of the 'Do Nothing' Scenario risk results. The following outlines the high-level results of the 'Do Nothing' Scenario.

- Total risk level for the 1,690 substation assets in 2026 is approximately 412,000, and approximately 4,065,000 for the 628 circuits (8,364 miles) for a total system risk score of 4,477,000. Risk levels are calculated by summing the risk for each asset, where risk is the product of the individual LOF and COF of each asset.
- The total portfolio system risk increased approximately 23.1 percent from 2019 to 2026 (see Section 4.4 for details).
- The total risk for the 411 assets (COF x LOF) in the High-Risk Region is approximately212,000, or approximately 51 percent of the total 2026 substation risk. The 147 circuits in the High-Risk Region have a risk of approximately 1,485,000, or approximately 37 percent of the total 2026 circuit risk.

Figure 1-2: 2026 Substation Asset Count Heat Map

Likelihood of Failure	2026 'Do Nothing' Risk Profile Asset Count					Total
Very High - 5	0	2	5	[redacted]	[redacted]	200
High - 4	[redacted]	2	4	104	[redacted]	224
Moderate - 3	[redacted]	[redacted]	7	210	294	528
Low - 2	[redacted]	[redacted]	1	122	109	243
Remote - 1	[redacted]	[redacted]	[redacted]	238	244	495
Total	1	36	25	722	906	[redacted]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure					

411 assets, or 24%, in High-Risk Region.

Figure 1-3: 2026 Circuit Count Heat Map

Likelihood of Failure	2026 'Do Nothing' Risk Profile Circuits Count					Total
Very High - 5	0	0	0	[redacted]	[redacted]	5
High - 4	[redacted]	0	0	0	[redacted]	142
Moderate - 3	[redacted]	[redacted]	3	5	256	264
Low - 2	[redacted]	[redacted]	2	15	155	173
Remote - 1	[redacted]	[redacted]	[redacted]	1	38	44
Total	0	5	6	21	596	[redacted]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure per Mile					

147 circuits, or 23%, in High-Risk Region.

1.4 Investment Scenarios

Three different investment approaches were modeled within the Asset Risk Model to calculate the resulting risk reduction benefit:

- IPL Seven-Year TDSIC Risk-Based Scenario (IPL TDSIC Risk-Based Scenario) – This investment case relies on the Asset Risk Model and invests capital to replace high-risk assets and maximize risk reduction benefit per dollar invested.
- LOF 4 Scenario – This investment scenario uses an asset's expected remaining life to prioritize investments and replace, over the 7-year period, all assets that fall within the LOF 4 (High) and 5 (Very High) categories in 2026. In other words, the Asset Risk Model replaces any asset that has a LOF above 60 percent. This scenario does not consider asset consequence.

- LOF 5 Scenario – This investment scenario uses an asset's expected remaining life to prioritize investments and replace, over the 7-year period, all assets that fall within the LOF 5 (Very High) category in 2026. In other words, the Asset Risk Model replaces any asset that has a LOF above 80 percent. This scenario does not consider asset consequence. Compared to the LOF 4 scenario, the LOF 5 scenario accepts more risk while lowering the required investment.

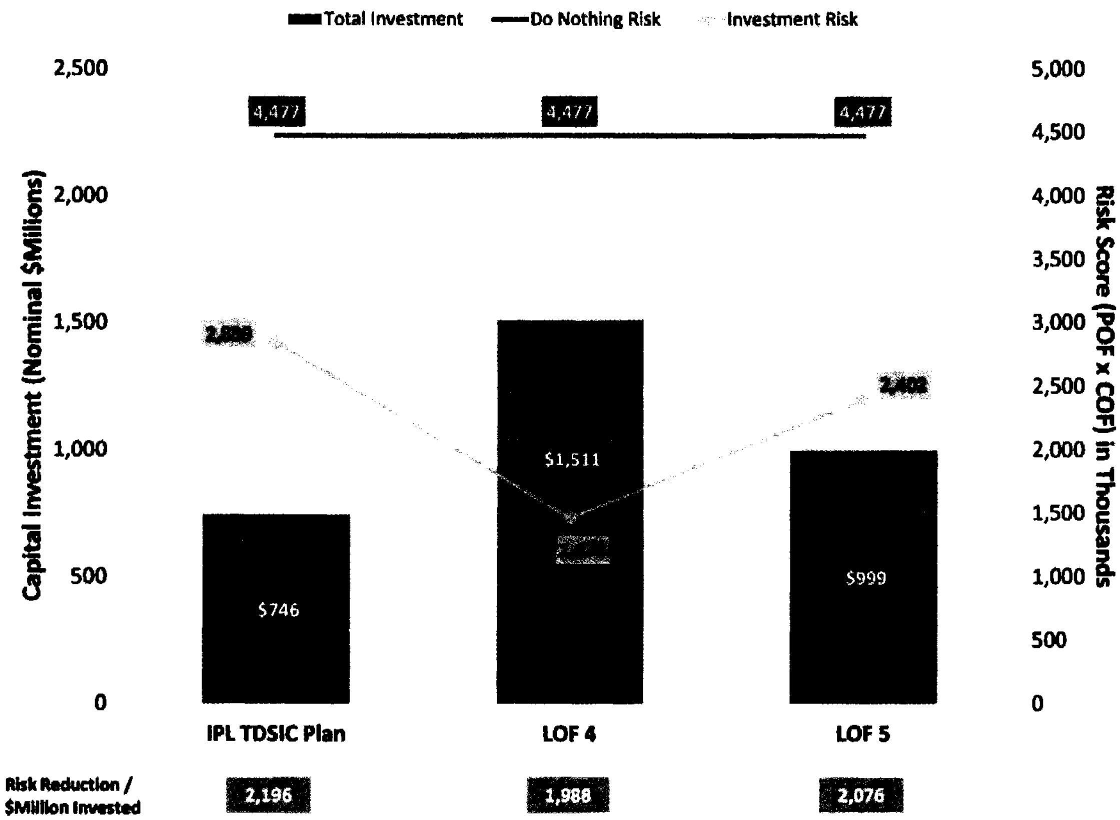
Further details on each of these scenarios are provided in Section 5.2. It should be noted that the Risk-Based Scenario includes risk results and investment levels for the following plans of IPL's TDSIC Plan:

- Substation Assets Replacement
- Circuit Rebuilds
- 4kv Conversion
- XLPE Cable Replacement
- Remote End – Breaker Relay/Upgrades

1.5 Business Case Summary

Section 5.0 describes in more detail the annual capital investments, risk before and after investment, and the business case summary for each of the investment scenarios outlined above. Figure 1-4 shows the results of the three investment scenarios. The red line represents the 'Do Nothing' risk results while the green line represents the resulting 2026 risk score of each scenario investment plan. The blue bars show the total 7-year investment for each scenario. The orange box shows the capital efficiency of the investment scenario in terms of risk reduction per million dollars invested.

Figure 1-4: Scenario Risk and Investment Summary Results



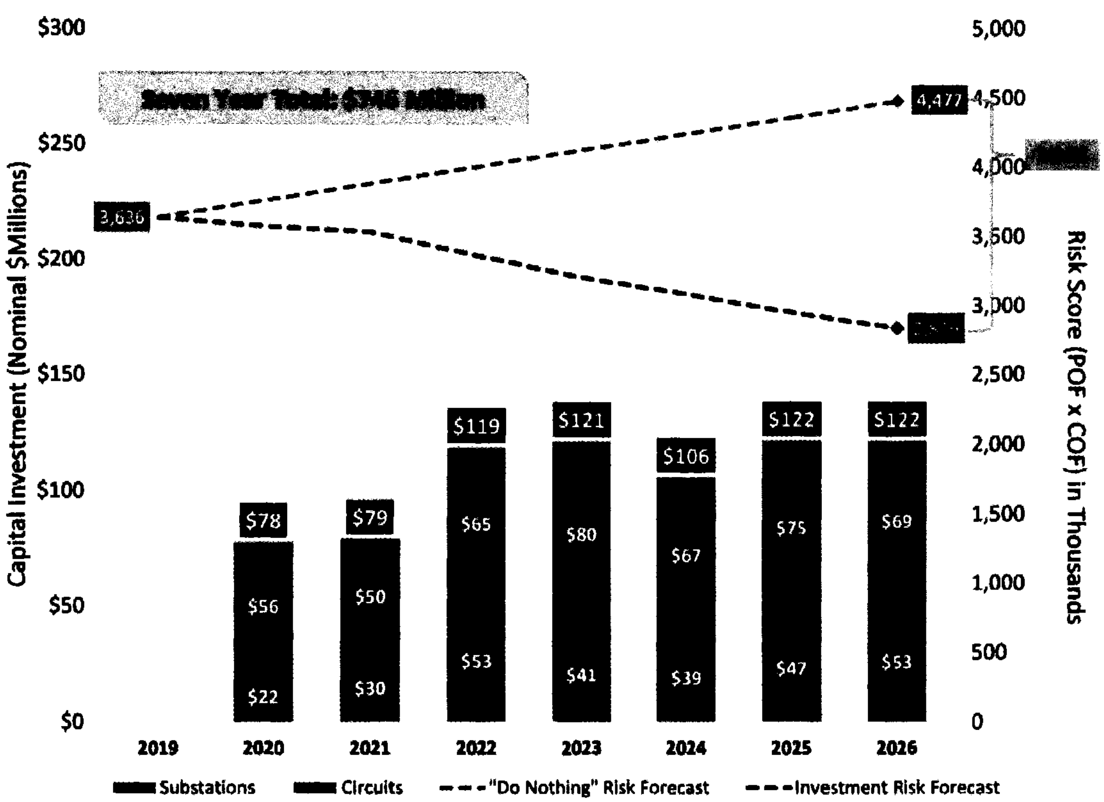
The figure and sections above show the following:

- The age-based investment scenarios LOF 4 and LOF 5 require more capital investment than the IPL TDSIC Plan scenario, $765 million and $253 million more for LOF 4 and LOF 5 scenarios, respectively.
- The IPL TDSIC Plan has the highest risk reduction efficiency of 2,196
- The IPL TDSIC Plan scenario replaces all the substation assets in the High-Risk Region. While the IPL TDSIC Plan does not remove all the circuits from the High-Risk Region, this is due to execution constraints. The LOF 4 plan removes all the substation assets from the High-Risk Region while the LOF 5 still have 159 assets. The LOF 4 and LOF 5 scenarios remove all or nearly all the circuits from the High-Risk Region.
- The IPL TDSIC Plan incorporates the other factors and constraints identified in Section 5-2 (e.g. project coordination, MISO outages, contractor limits) to execute investments over the 7-year period.

- While the LOF 4 and LOF 5 scenarios have more risk reduction than the IPL TDSIC Plan scenario, they come at a significantly higher cost and lower risk reduction per dollar invested. The LOF 4 and LOF 5 scenario capital efficiencies (1,988 and 2,076, respectively) are less than that of the IPL TDSIC Plan (2,196).

As discussed throughout the report, IPL utilized a risk-based planning approach in creating a 7-year TDSIC capital plan with the goal of managing high-risk assets and providing economic risk reduction. The IPL TDSIC Plan manages the risk with all the assets in the High-Risk Region up to IPL's executable constraints, while achieving the highest capital efficiency and spending less than the LOF 4 and LOF 5 scenarios. Figure 1-5 shows the annual details of the IPL TDSIC Plan. The Risk-Based Scenario includes a total of $746 million with a risk reduction of 36.6 percent.

Figure 1-5: IPL TDSIC Risk-Based Scenario Capital Investment vs. Risk Profile



2.0 RISK BASED PLANNING APPROACH

IPL utilized a risk-based planning approach to prioritize investment in the T&D system. While risk-based planning approaches have many purposes, two key purposes for the Asset Risk Model are:

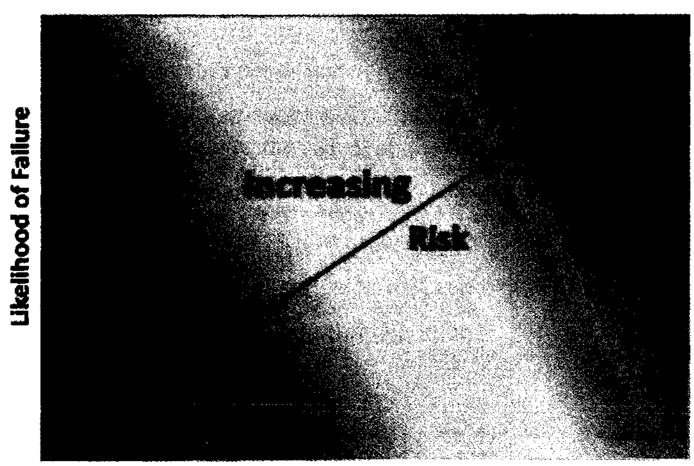
1. Identify high-risk assets and establish a plan to manage the risk.
2. Identify the highest risk reduction per dollar invested for the system.

The risk-based planning approach calculates the risk at an asset level, thus creating an Asset Risk Model, which IPL used as a tool in the development of the TDSIC projects. The Asset Risk Model identifies high-risk assets for the T&D system using asset condition, age, and consequence and calculates the risk reduction benefit of replacing those assets. Specifically, the model quantifies the expected risk reduction over the 7-year TDSIC planning period from 2020 through 2026.

2.1 Risk and Risk Management

In aligning with best practice asset management and ISO 31000, the Asset Risk Model defines risk for an asset as being the product of the likelihood of failure and the consequence or impact caused by the failure. Typically, risk results are visualized using a risk grid/matrix, or heat map. An example risk grid is show in Figure 2-1 below.

Figure 2-1: Risk Matrix



Similarly, the Asset Risk Model adheres to best practice and ISO standards for risk management. The basic framework for the risk assessment follows the process below:

- Risk identification – the asset register, asset definition, and expected asset failure mode
- Risk assessment – consequence and likelihood frameworks including asset health
- Risk mitigation measure development – asset replacements and project bundling
- Risk mitigation measure implementation – executing the mitigation plan

The remaining sub-sections describe the risk identification and the approach to the risk assessment in development of the Asset Risk Model. Section 3.0 provides the results of the risk assessment, and Section 5.0 shows the risk management approach and results in creating IPL's 7-year TDSIC Risk-Based Scenario. The Asset Risk Model uses the process and approach outlined above for assessing risk.

2.2 Likelihood of Failure (LOF) Forecast

The Asset Risk Model forecasts the LOF for each asset assuming an age-based failure event that requires the asset to be replaced. In other words, the Asset Risk Model forecasts the 'end-of-life' failure event. Survivor curves are widely used in the utility industry and asset management organizations to forecast the likelihood of this type of failure event. The Asset Risk Model uses survivor curves to forecast the LOF for each asset. Additionally, the Asset Risk Model uses asset condition information to calculate asset health and represent differences between chronological age and actual deterioration. More simply, the Asset Risk Model uses asset specific condition information to determine an asset's 'effective' age. The following sections provide more detail on survivor curves, calculating LOF, and incorporating asset health to determine an asset's 'effective' age.

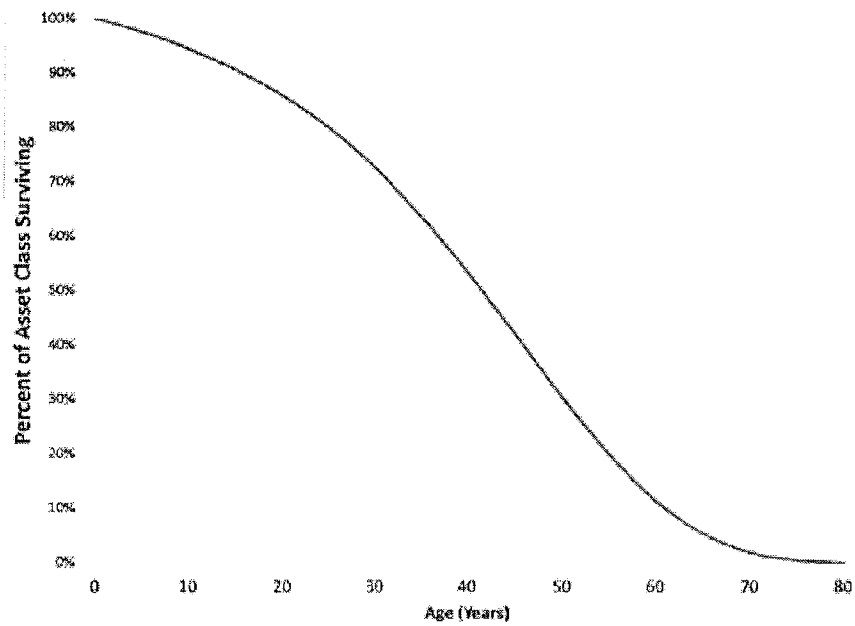
2.2.1 Survivor Curves

Survivor curves are commonly utilized in asset management solutions to forecast LOF by estimating the percentage of a population in an asset class that is surviving over time. Since most utilities work to prevent failures, there is simply not enough actual historical failure data to perform a statistical analysis and develop deterioration curves. As such, Iowa Survivor Curves are utilized to model asset class survivability and calculate the LOF over time. Iowa Survivor Curves are widely used in the utility industry in depreciation studies for establishing rates.

The Asset Risk Model designates an Iowa Survivor Curve for each asset class. Survivor curves were assigned to each asset class based on IPL's 2017 Depreciation Study[3] in addition to industry knowledge of expected life of various asset classes and IPL's experience with asset expected life. Figure 2-2 shows an example survivor curve for substation breakers.

[3] This depreciation study was presented to the Commission in Cause No. 45029.

Figure 2-2: Example Survivor Curve for Substation Breakers



2.2.2 Likelihood of Failure (LOF) Calculation

The LOF forecast for an asset is calculated using the percentage surviving, as noted on the y-axis of the survivor curve, and the effective age of an asset (approach described below). One important note, the LOF calculation is forward looking and disregards the part of the survivor curve that is younger than the asset's effective age. Figure 2-3 illustrates this concept for an example 138 kV Breaker. As the figure shows, the part of the curve before age 30 is not considered in calculating the forecast.

A survivor curve is used to calculate the discrete failure likelihood for each year for the asset. Then, these discrete likelihoods are totaled for a given, forward-looking timeframe to forecast the LOF for the next 10 years. Table 2-1 provides an example calculation for a 30-year-old asset with a LOF horizon of 10 years.

Figure 2-3: LOF Calculation Example – 138 kV Breaker

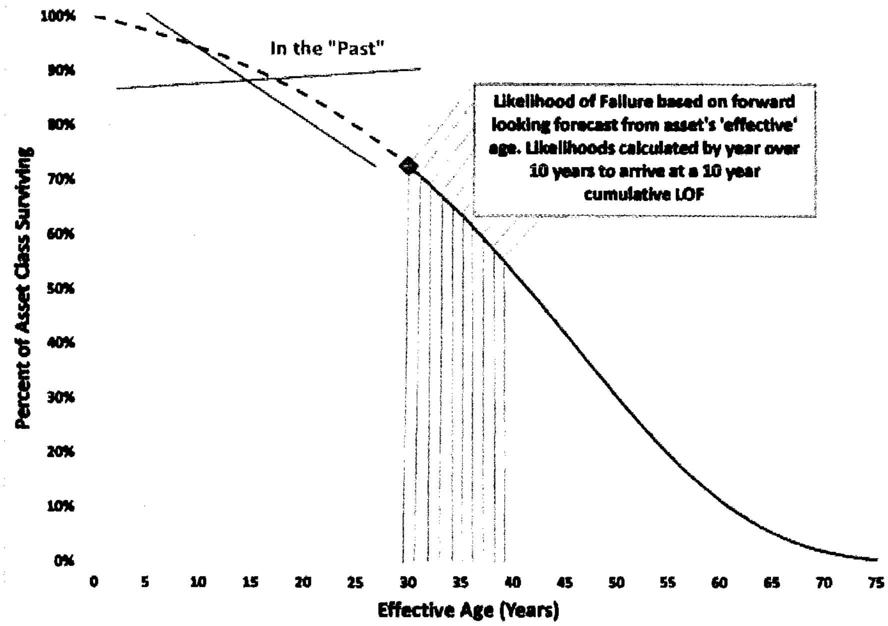


Table 2-1 Example LOF Calculation – 138 kV Breaker

Age	Forecast Year	Discrete LOF	Cumulative LOF
31	1	2.27%	2.27%
32	2	2.35%	4.62%
33	3	2.44%	7.06%
34	4	2.53%	9.59%
35	5	2.62%	12.21%
36	6	2.70%	14.91%
37	7	2.78%	17.69%
38	8	2.86%	20.55%
39	9	2.94%	23.49%
40	10	3.00%	26.49%

2.2.3 Estimating Effective Age

Where available, an asset's condition, coupled with an understanding of the asset's various failure modes, provides a better data set for estimating an asset's remaining useful life. Understanding the remaining useful life allows the analysis to account for older assets that may have more years left on their life than would otherwise be assumed based on their age, and vice versa. The practice of updating an asset's chronological age to reflect condition data yields an asset's 'effective' age. An asset's condition is affected by several factors. The following list includes many of the common factors:

- Loading and Cycling
- Operations
- Maintenance (quality, type, and frequency) and service history
- Animals and insects
- Weathering (temperature, wind, snow/ice, rain, lightening etc.)
- Defects caused by external events (human)
- Combination of the above

2.2.3.1 Asset Health Index (AHI) Approach

An AHI is an indexed score of an asset's relative health based on several measures that incorporate condition information. The Asset Risk Model calculates an AHI score for power transformers, breakers, and wood poles. The Asset Risk Model utilizes IPL's existing AHI framework and asset scoring for power transformers and breakers. Additionally, the Asset Risk Model utilizes Burns & McDonnell's framework and scoring for wood poles. It should be noted that IPL has shared the AHI framework for power transformers and breakers in recent collaborative efforts with IPL Stakeholders[4].

In general, the Asset Health Framework includes several categories, each weighted to calculate the final Asset Health Score. The weighting is included to reflect the relationship between the Asset Heath metric and the asset's condition. Each Asset Health Score measures the relative condition of the asset based on the following general ratings:

- Very High
- High
- Moderate
- Low
- Remote

Figure 2-4 shows a summary of the AHI approach employed for power transformers. Scoring based on this framework was applied to all 217 power transformers. IPL used condition monitoring data (e.g. DGA) as well as the knowledge and experience of IPL subject matter experts to provide scores for all the power transformers.

[4] See Footnote 2

Figure 2-4 Power Transformer AHI Approach Summary

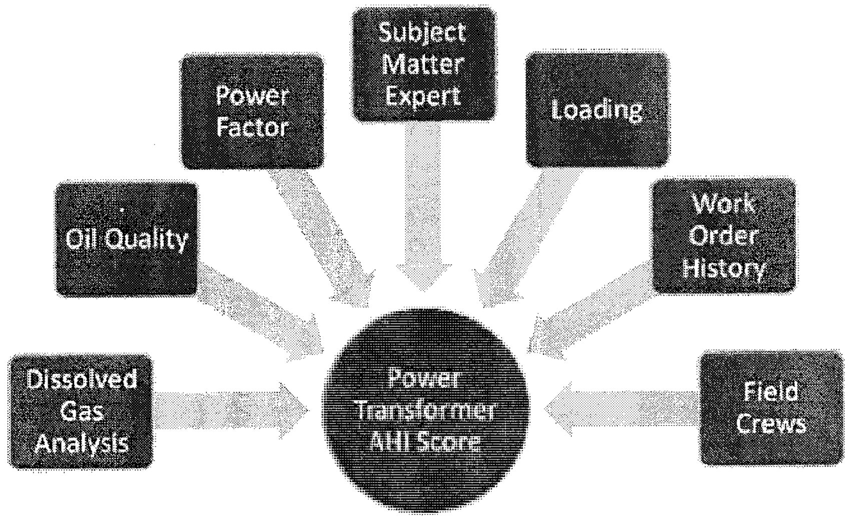
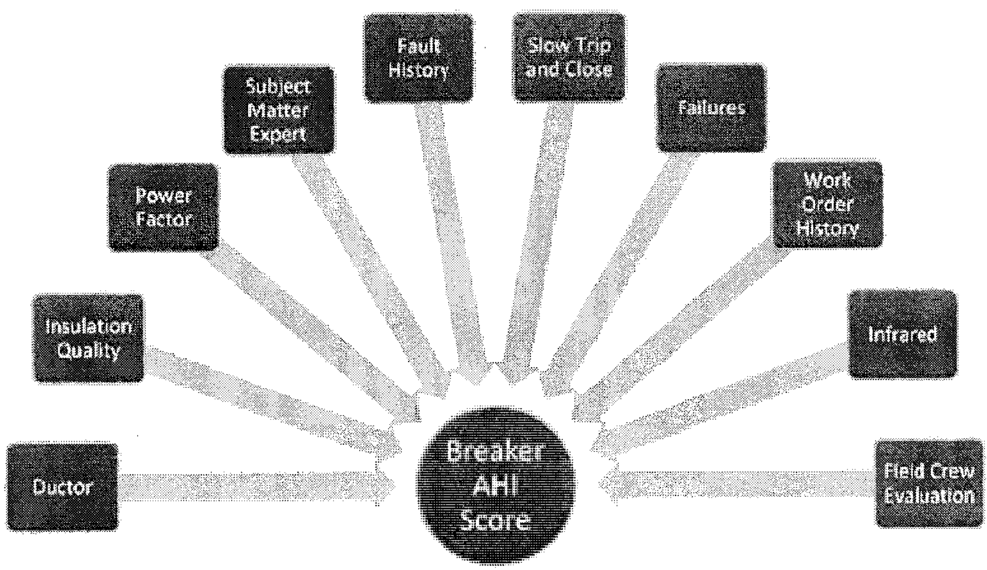


Figure 2-5 provides a summary of the AHI approach for substation breakers. As noted above, this framework was largely developed by IPL, normalized by Burns & McDonnell, and shared with the Commission and other interested parties in the recent collaborative effort[5]. Similar to the power transformers, this framework was used to calculate AHI scores for 1,359 breakers. Scoring of the breakers followed a similar approach as the power transformers.

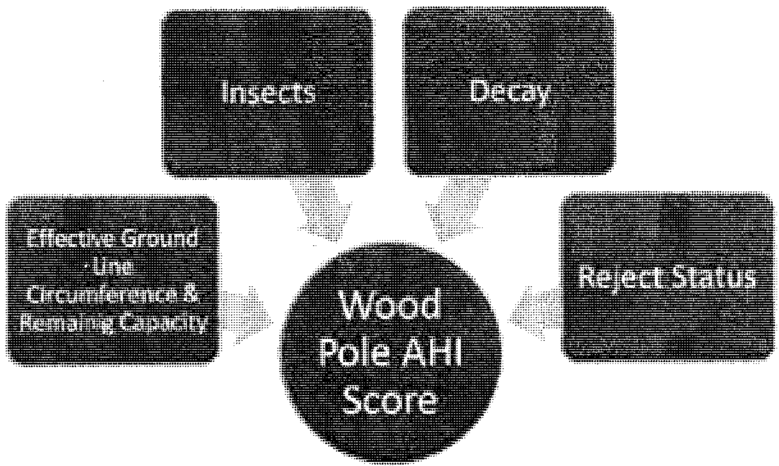
Figure 2-5 Breaker AHI Approach Summary



[5] See Footnote 2

For wood poles, the Asset Risk Model utilizes Burns & McDonnell's asset health framework. Burns & McDonnell utilized IPL's pole inspection information to determine the asset health for 138,256 poles. Pole inspections for IPL are done on a 10 year cycle. During the inspections, every pole is visually inspected and measured. Some assets have more detailed inspections performed, including boring or underground testing. Figure 2-6 provides a summary of the wood pole AHI approach. Scoring for all 138,256 poles was based on the wood pole AHI framework and wood pole inspection at the individual pole level.

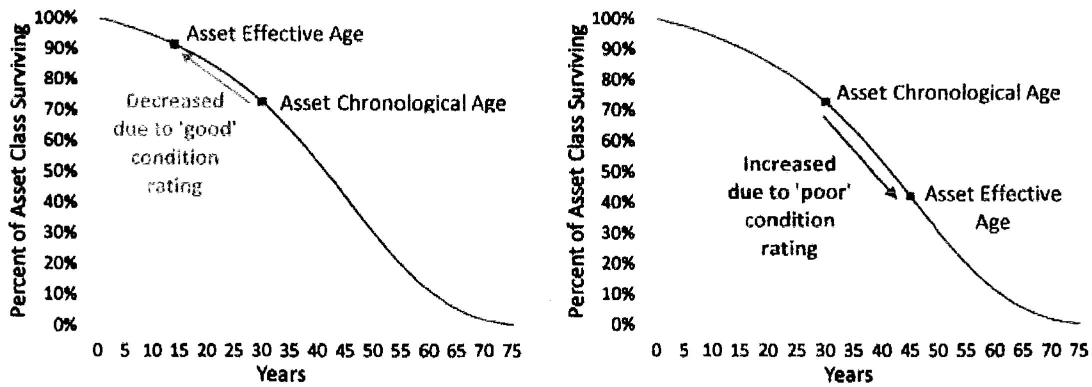
Figure 2-6 Wood Pole AHI Approach Summary



2.2.3.2 Applying Effective Age

Using the asset health indices, the asset's location on the survivor curve is adjusted to reflect their condition. Better than expected condition is used to adjust the asset age so it is younger than its chronological age, and vice versa. Figure 2-7 illustrates how 'effective' age is used to adjust an asset's chronological age based on 'good' and 'poor' condition ratings, respectively.

Figure 2-7 Effective Age Example



In general, the average asset age decreased with the AHI approach. his means that the AHI approach moved more assets from the higher L F to the lower L F regions of the heat matrix, thereby reducing the amount of investment recommended per the Asset Risk Model.

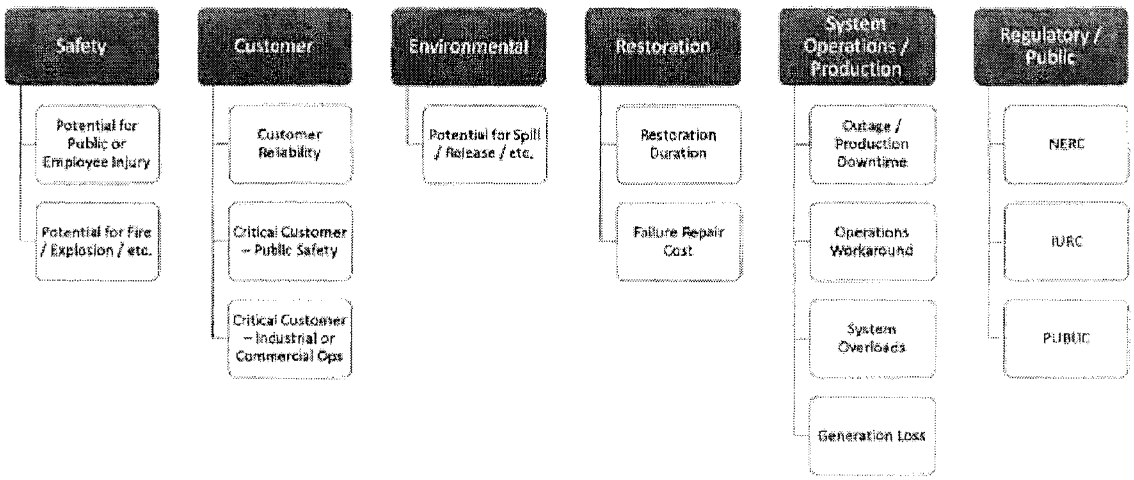
2.3 Consequence of Failure (COF)

his section describes the development of the F framework for IPL. IPL has an existing conse uence framework for transformer and breaker assets. he framework for these assets was initially developed by IPL staff and was recently reviewed in a collaborative effort with IPL Stakeholders . Burns & McDonnell leveraged IPL's existing conse uence framework for transformers and breakers and adjusted Burns & McDonnell's own framework for distribution circuits to create a global and holistic framework, applicable to all asset classes.

o weighting factors are applied across the framework, rather the magnitude of the conse uence scoring framework has been designed to reflect the relative difference in conse uence for an overhead distribution section versus a high voltage breaker. For example, the conse uence framework includes scores as low as 6.6 for a distribution section and scores as high as 700 for a large high voltage breaker.

he F framework for each asset class includes the following categories 1 safety, 2 customer, 3 environmental, restoration, 5 systems operations production, and 6 regulatory public. he F criteria in the Asset Risk Model are presented in Figure 2-8.

Figure 2-8 Consequence of Failure Criteria



All assets in the Asset Risk Model are scored against this framework. For the substation assets power transformers, breakers, and batteries most of the asset scoring was provided by IPL. ith a manageable number of substation assets, IPL staff scored each asset manually, while some of the criteria were filled out using existing data sources. However, with the large number of circuit assets, existing data sources were leveraged i.e. database of circuit assets serving critical customers, database of poles with pole mounted transformers along with some manual input.

An example breaker conse uence score calculation is shown in able 2-2. he framework is configured with categories and subcategories. For scoring, the maximum subcategory score is taken as the category score and is used in the final calculation for an asset's F. he maximum value in each category is summed for a total conse uence score of 700.

he Asset Risk Model also aligns each conse uence score to one of the following conse uence ratings for alignment to the risk grid, which is discussed further in Section .0 and 5.0.

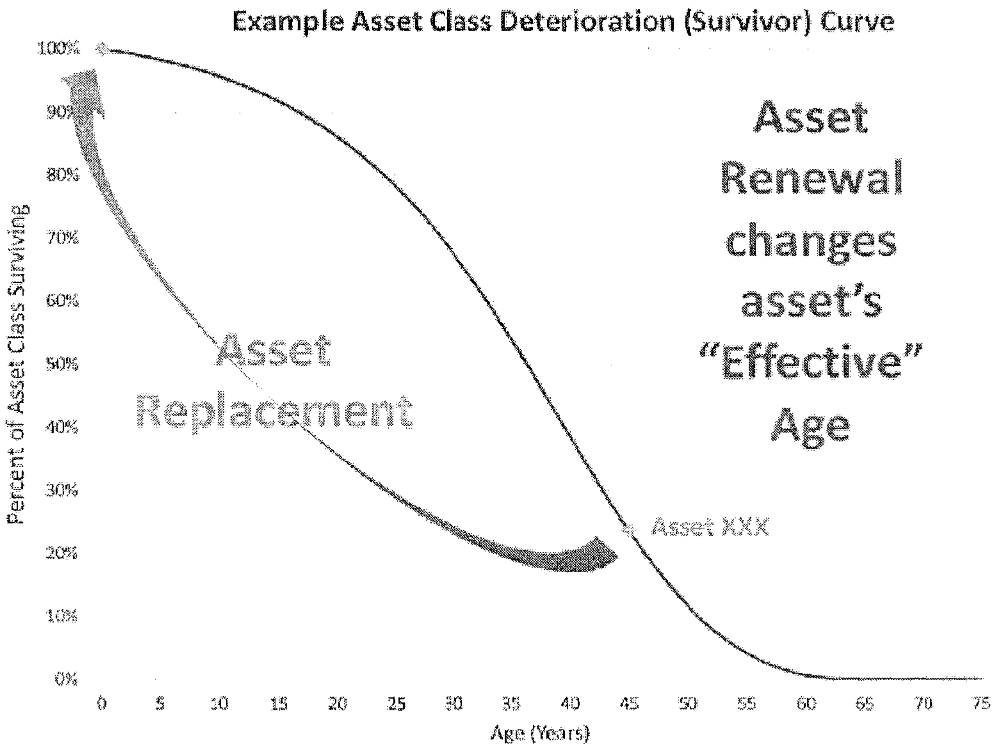
- ery Low 1
- Low 2
- Moderate 3
- High
- ery High - 5

Table 2-2: 138 kV Breaker (Allison #4 Bus Tie)

Consequence Category	Consequence Subcategory	Score	Max
Safety	Potential for Public or Employee Injury	250	250
	Potential for Fire/Explosion/etc.	250	
Customer	Customer Reliability	0	50
	Critical Customer	0	
	Industrial Customer	50	
Environmental	Potential for Spill / Release / etc.	50	50
	Impact of Spill / Release / etc.	50	
Restoration	Restoration Duration	35	150
	Failure Repair Costs	150	
Productivity/Reliability	Outage / Production Downtime	2	100
	Operations Workaround	100	
	Control Contingency Overloads	100	
	Generation Loss	0	
Regulatory/Company Image	NERC	0	100
	IURC	0	
	Public	100	
Criticality Score	**Total**		**700**

2.4 Risk Reduction and Residual Risk

Figure 2-9: Survivor Curve and Asset Replacement



Using this approach, the Asset Risk Model calculates the residual risk of the asset. Table 2-3 provides an example calculation for the residual risk of the replacement for a zero-year-old 138 kV breaker. Comparing Table 2-1 and Table 2-3 shows a total LOF reduction of 20.93 percent (from 26.49 percent to 5.56 percent) if the asset is replaced in the first year of the forecast period.

Table 2-3 Example LOF Calculation for Asset Replacement – 138 kV Breaker

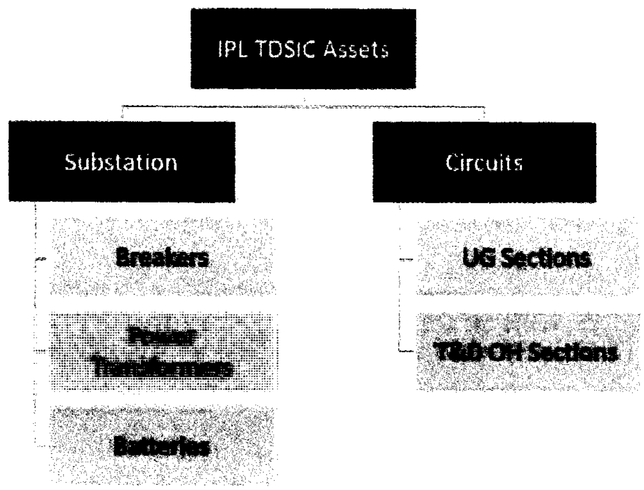
Age	Forecast Year	Discrete LOF	Cumulative LOF
1	1	0.45%	0.45%
2	2	0.47%	0.92%
3	3	0.49%	1.41%
4	4	0.52%	1.93%
5	5	0.54%	2.47%
6	6	0.56%	3.03%
7	7	0.59%	3.62%
8	8	0.62%	4.24%
9	9	0.65%	4.88%
10	10	0.67%	5.56%

In general, asset replacements do not impact COF, however, for a few asset classes risk is also reduced through a decrease in the COF score. Oil circuit breakers and certain types of conductor (covered) include a decrease in environmental and safety scores respectively.

3.0 OVERVIEW OF T&D ASSETS IN RISK MODEL

A critical first step in building an asset risk model is defining what constitutes an 'asset'. This provides the appropriate boundary for understanding the failure mode of an asset. Figure 3-1 depicts the individual asset classes that are included in the Asset Risk Model organized by substation and circuit categories. Specifically, the asset classes include breakers, power transformers, batteries, underground sections, and transmission and distribution overhead sections.

Figure 3-1: TDSIC Asset Class Configuration



3.1 Substation Assets

The substation assets evaluated as part of the TDSIC modeling include IPL's breakers, power transformers, and batteries[7]. Table 3-1presents the count of each of these asset types.

Table 3-1: Substation Asset Type Counts

Asset Type	Total
Breakers	1,359
Power Transformers	217
Batteries	114
Total	**1,690**

The transmission voltage levels of IPL's system include 138 kV and 345 kV. The distribution voltage levels of IPL comprise 4 kV, 13.2 kV, and 34.5 kV (34.5 kV is also sometimes referred to as sub-

[7] While batteries are located throughout the system both in substations and circuits, most are located within substations. For this reason, they have been categorized as a substation asset for purposes of TDSIC planning.

transmission). Table 3-2 includes the detailed counts of the breakers and power transformers of the distribution and transmission voltage levels. The power transformers are categorized using their low side voltages.

Table 3-2: Transmission and Distribution Asset Counts in TDSIC

Voltage Class	Breakers	Power Transformers
Distribution		
4 kV	116	62
13.2 kV	814	133
34.5 kV	164	12
Total Distribution	1,094	207
Transmission		
138 kV	229	10
345 kV	36	0
Total Transmission	265	10
T&D Total	**1,359**	**217**

3.2 Circuits or Linear Assets

The Asset Risk Model includes underground and overhead linear assets for transmission and primary service. Secondary cable was not included in the Asset Risk Model. Table 3-3 shows a summary of the miles of linear assets included in the Asset Risk Model. It should be noted that the table provides circuit miles (i.e. 1 mile of single phase = 1 mile of two phase = 1 mile of three phase), not miles of conductor wire or cable.

Table 3-3: IPL Circuit Summary

Asset Type	Circuit Miles
Transmission and Sub-Transmission	1,135
Overhead Primary Distribution	3,677
Underground Primary Distribution	3,977
Total	**8,789**

The Asset Risk Model defines a linear asset as a section or segment of the system. The following two sections describe in more detail how the sections are generated. Table 3-4 provides a summary of the number of underground and T&D overhead (OH) sections in the Asset Risk Model. Modeling the circuit assets at this level allows for the identification of specific high-risk spans/segments and comparison at the span and segment level across all circuits as opposed to a circuit by circuit comparison. It should be noted that distribution circuits have a wide range of asset ages dependent on system growth and circuit re-configurations. In some instances, the mainline or backbone of a circuit may be relatively young but the ties or laterals are much older because those laterals were moved over to the new circuit backbone when it was built to balance system load. Modeling at the span/segment level provides the necessary granularity circuit by circuit to identify the specific high-risk portions of a circuit to replace.

Table 3-4: TDSIC Linear Asset Summary

Asset Type	Sections	Circuit Section Miles
Underground Sections	57,981	3,977
T&D OH Sections	160,194	4,387
Total	**218,175**	**8,364**

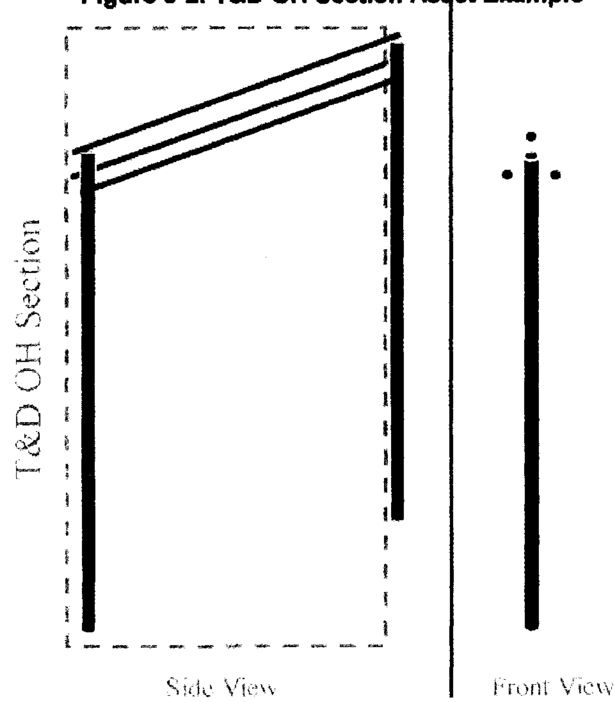
3.2.1 Underground Sections

Underground sections are defined by IPL's GIS application. Burns & McDonnell used IPL's GIS application asset hierarchy for the underground system to generate the underground sections. IPL's GIS application identified these sections based on their beginning and end points, which are typically manholes, vaults, distribution circuit transformers, or other structures.

3.2.2 T&D Overhead (OH) Sections

While the T&D OH system is made of up several types of assets (poles, towers, and wires), the Asset Risk Model defines an overhead linear asset as a single pole/tower (i.e. vertical structure) and the length of the wire(s) from the structure attachment to the spot just before attachment to the next structure. While circuits are electrically separated, many are connected physically through the pole/tower (i.e. double or even triple circuits on a single vertical structure). Figure 3-2 illustrates this approach where a T&D OH Section is a single asset in the Asset Risk Model.

Figure 3-2: T&D OH Section Asset Example



The calculation of risk for each T&D OH Section is the sum of the risk of its parts, the pole or tower and the associated wires (transmission or primary). Table 3-5 provides a summary of the asset base for the T&D overhead section. Every asset is assigned to one of the 160,194 T&D OH Sections.

Table 3-5: Circuit Asset Type Counts

Asset Type	Units	Count
Towers	count	4,065
Wood Poles	count	138,256
Transmission Conductor	circuit miles	1,135
Primary Conductor	circuit miles	7,653

IPL's system comprises various conductor configurations, as illustrated in the Figure 3-3. Each of these configurations represents the type of T&D OH Sections in the Asset Risk Model. While there are dozens of other configurations, the configurations illustrated below generally characterizes most of IPL's system. The configurations include single or double circuits (even triple circuits), two phase or single phase, as well as configurations of both transmission/sub-transmission and distribution. Static and neutral wires have been excluded from the figure.

Figure 3-3: T&D OH Section Configurations (Front View)

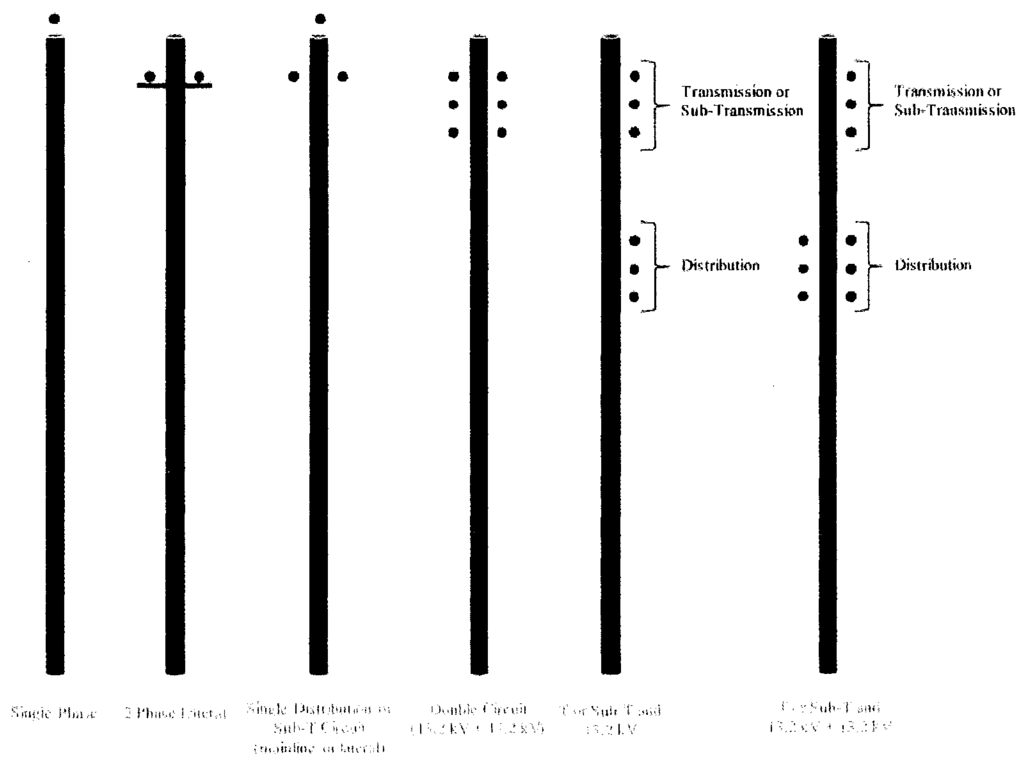


Table 3-6 includes a summary of the most prevalent types of T&D OH Sections as well as the portion of the system that is made up of each type of section.

Table 3-6: T&D OH Section Types

Section Type	Section Miles	Portion of System
13.2 KV - 1 phase	1,385	31.6%
13.2 KV - 3 phase	1,544	35.2%
345 KV	406	9.3%
13.2 KV - 2 phase	220	5.0%
138 KV – tower	114	2.6%
13.2 KV + 13.2 KV	111	2.5%
34.5 KV	101	2.3%
34.5 KV + 13.2 KV	89	2.0%
138 KV – pole	62	1.4%
138 KV + 138 KV	55	1.2%
Other	299	6.8%
Total	**4,387**	**100%**

It should be noted that Table 3-6 and Table 3-4 show the total number of section miles whereas Table 3-3 shows the number of circuit miles. As such, Table 3-6 and Table 3-4 show fewer miles due to several sections including double or even triple circuits.

4.0 'DO NOTHING' SCENARIO

The "Do Nothing' or 'Run-to-Failure' scenario quantifies the increase in risk that IPL carries over time if proactive replacements are not made. This approach involves allowing the assets to age over a 7-year period without replacements. This scenario establishes the baseline to compare the risk reduction for the various investment scenarios outlined in Section 5.0. This approach is appropriate because few utilities, including IPL, have a long-term (5 to 10 year) baseline for capital improvements with specific projects. In the absence of an status quo alternative baseline scenario, the 'Do Nothing' scenario is an appropriate baseline to compare other scenarios. 'Do Nothing' scenarios are routinely used to perform analysis such as that presented in this report.

A key tool to visualize and understand risk is the risk grid/matrix, also known as a heat map. Figure 4-1 provides the risk grid framework used throughout the rest of the report with LOF on the vertical axis, and COF on the horizontal axis. It should be noted that the probabilities on the vertical axis comprise the likelihood of failure over a 10-year period.

Figure 4-1: Risk Grid Framework

			Risk Matrix				
Likelihood of Failure	Very High - 5	80%+					
	High - 4	60% - 80%					
	Moderate - 3	40% - 60%					
	Low - 2	20% - 40%					
	Remote - 1	0% - 20%					
			0 - 100	100 - 200	200 - 300	300 - 400	400+
			Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5
			Consequence of Failure				

Using this visualization tool, asset counts or, alternately, risk scores associated with those asset counts are provided for each of the 25 boxes. As described in more detail in Section 5.0, the location of an asset within the risk grid provides guidance into the type of risk mitigation strategy necessary.

4.1 Assumptions

The analysis assumes the following:

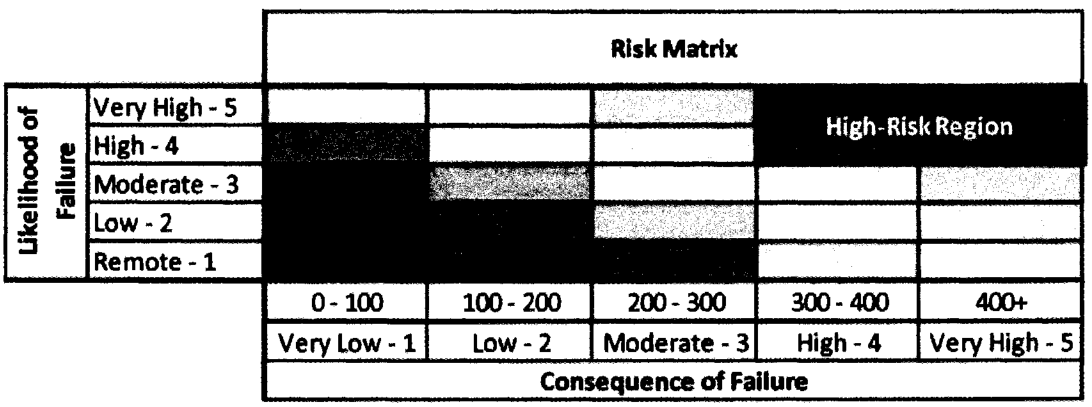
- Assets will be subject to normal ageing over the seven years
- COF ratings remain unchanged over the analysis period

- In the modeling scenario, any repairs done to an asset would restore it to service but would leave the age and service life unchanged
- No new assets are added into the scenario during the 7-year analysis

4.2 High-Risk Region

As mentioned throughout this report, one of the key purposes of risk-based planning for IPL is to manage high-risk assets. IPL identified assets in the 2x2 box located in the upper right-hand corner of the risk grid as high-risk assets, as shown in Figure 4-2. This defined area is also known as the High-Risk Region. This region contains assets with either a high or very high COF and LOF. Section 5.2.2 outlines the approach utilized to manage the risk in this region. The 'Do Nothing' results below highlight the number of assets in this region as well as the risk in this region compared to that of the whole system.

Figure 4-2: Heat Map High-Risk Region



4.3 'Do Nothing' Risk Assessment

The 'Do Nothing' risk assessment results are presented according to the two key asset bases in the Asset Risk Model, substations (asset count based) and circuits (aggregate of the total circuit miles). The combined risk profile results over the 7 years are provided in Section 4.4.

4.3.1 Substations

Figure 4-3 shows the 2019 'Do Nothing' heat maps for the 1,690 substation assets. As shown in the heat map, there are 244 assets in the High-Risk Region, representing approximately 14 percent of the asset base. As outlined above, these assets are prioritized for mitigation. The figure also shows that most of the assets are in the Moderate to Very High consequence range of the risk grid. The total risk score for the 1,690 substation assets is approximately 320,000. This number is calculated by summing the risk score for every asset where risk is the product of the asset LOF and COF. The total risk for 244 assets in the High-Risk Region is approximately 127,000, or approximately 40 percent of the total substation risk. The

High-Risk Region accounts for 14 percent of the substation asset base, but 40 percent of the substation risk in 2019.

Figure 4-3: 2019 Substation Asset Count Heat Map

Likelihood of Failure	2019 'Do Nothing' Risk Profile Asset Count					Total
Very High - 5	0	0	0	[redacted]	[redacted]	106
High - 4	[redacted]	4	5	51	[redacted]	147
Moderate - 3	[redacted]	[illegible]	3	122	210	349
Low - 2	[redacted]	[redacted]	8	190	252	464
Remote - 1	[redacted]	[redacted]	[redacted]	316	294	624
Total	1	36	25	722	906	[redacted]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure					

244 assets, or 14%, in High-Risk Region.

Figure 4-4 shows the heat map in 2026, 7 years later. Since consequence is assumed to remain constant over time, the assets move up the risk grids to higher likelihoods of failure over the period, while keeping constant the number of assets included in each consequence category. The figure shows 411 assets, approximately 24 percent of the substation asset base, in the High-Risk Region, an increase of 167 assets, from 244 to 411, over the 7-year period. That is an increase in the amount of assets within the High-Risk Region of approximately 68 percent.

Figure 4-4: 2026 Substation Asset Count Heat Map

Likelihood of Failure	2026 'Do Nothing' Risk Profile Asset Count					Total
Very High - 5	0	2	5	[redacted]	[redacted]	200
High - 4	[redacted]	2	4	104	[redacted]	224
Moderate - 3	[redacted]	[illegible]	7	210	294	528
Low - 2	[redacted]	[redacted]	1	122	109	243
Remote - 1	[redacted]	[redacted]	[redacted]	238	244	495
Total	1	36	25	722	906	[redacted]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure					

411 assets, or 24%, in High-Risk Region.

The total risk for the 1,690 assets in Figure 4-4 is approximately 412,000. That is an increase of approximately 29 percent over the 7-year period. The total risk for the 411 assets in the High-Risk Region is approximately 212,000, or approximately 51 percent of the total 2026 substation risk. Over the 7-year period, the substation risk level in the High-Risk Region increased from 40 percent in 2019 to 51 percent in 2026. In 2026, the High-Risk Region accounts for 24 percent of the substation asset base but 50 percent of the substation risk.

4.3.2 Circuits

This section shows similar results to those in the substation section above. While circuit assets are modeled at the section level, for representation within the heat map the spans have been aggregated to the circuit level and then normalized on a per circuit mile basis to avoid biasing the results for longer circuits. The reason for this approach is the nature of the asset base, distribution assets are critical or strategic on a collective basis, not on an individual basis like many of the substation assets.

Figure 4-5 shows the 2019 'Do Nothing' heat maps for circuits. A circuit's location on the LOF axis is based on the weighted average of the LOF scores for all the sections on the circuit. As an example, the 218 circuits in the Moderate LOF include a section in each of the LOF categories but average out to a Moderate. As shown in the heat map, most of the circuits are in the Moderate to Very High consequence region of the grid and Low to Moderate regions of the likelihood categories. The total 2019 risk for the 628 circuits is approximately 3,316,000. This score is calculated by summing the risk score for all underground and overhead T&D sections for all circuits.

The total risk for 47 circuits in the High-Risk Region is approximately 346,000, or approximately 10 percent of the total circuit risk. The High-Risk Region accounts for 7 percent of the circuit asset base, but 10 percent of the circuit risk in 2019.

Figure 4-5: 2019 Circuit Count Heat Map

Likelihood of Failure	2019 'Do Nothing' Risk Profile Circuit Count					Total
Very High - 5	0	0	0			2
High - 4		0	0	0		45
Moderate - 3			0	1	217	218
Low - 2			3	12	251	267
Remote - 1				8	81	96
Total	0	5	6	21	596	
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure per Mile					

47 circuits, or 7%, in High-Risk Region.

Figure 4-6 shows the heat map in 2026, 7 years later. Since consequence is assumed to remain constant over time, the circuits move up the risk grids over the period, while keeping constant the number of circuits included in each consequence category. The figure shows 147 circuits, approximately 23 percent of the circuit asset base, in the High-Risk Region. An increase of 100 circuits over the 7-year period. That is an increase in the amount of circuits within the High-Risk Region of 213 percent.

The total risk for the 628 circuits in Figure 4-6 is approximately 4,065,000. That is an increase of approximately 23 percent over the 7-year period. The total risk for the 147 circuits in the High-Risk Region is approximately 1,485,000, or approximately 37 percent of the total 2026 circuit risk. Over the 7-year period, the circuit risk level in the High-Risk Region increased from 10 percent in 2019 to 37 percent in 2026. In 2026, the High-Risk Region accounts for 23 percent of the circuit asset base but 37 percent of the circuit risk.

Figure 4-6: 2026 Circuit Count Heat Map

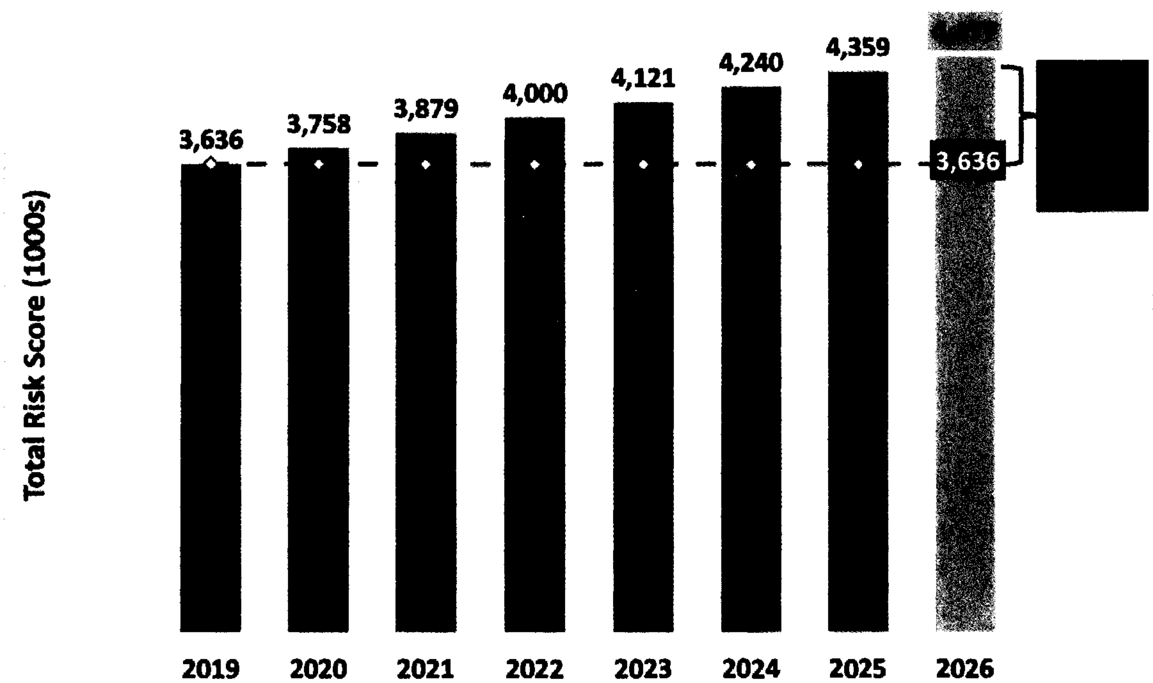
		2026 'Do Nothing' Risk Profile Circuits Count					Total
Likelihood of Failure	Very High - 5	0	0	0	[illegible]	[redacted]	5
	High - 4	[illegible]	0	0	0	[illegible]	142
	Moderate - 3	[redacted]	[illegible]	3	5	256	264
	Low - 2	[redacted]		2	15	155	173
	Remote - 1	[redacted]			1	38	44
	Total	0	5	6	21	596	[illegible]
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
		Consequence of Failure per Mile					

147 circuits, or 23%, in High-Risk Region.

4.4 'Do Nothing' Seven Year Risk Profile

Figure 4-7 shows the total risk score profile for both the substation and circuit assets for the 'Do Nothing' scenario from 2019 to 2026. As the figure shows, total system risk increases by approximately 23.1 percent over the 7-year planning period.

Figure 4-7: 'Do Nothing' Risk Forecast, 2019 to 2026



5.0 INVESTMENT SCENARIO RESULTS

5.1 Overview

IPL utilized a risk-based planning approach to prioritize investment in the T&D system. This section will present the investment case scenarios utilized in the TDSIC business case evaluation. The 'Do Nothing' approach (Section 4.0) serves as a baseline for calculating risk reduction benefit. The investment scenario results include the capital outlay in each, the risk before and after investment, and the business case summary.

5.2 Risk Model Scenarios

Three different investment approaches were modeled within the Asset Risk Model to calculate the resulting risk reduction benefit and understand if any assets still exceeded IPL's risk tolerance levels. The three scenarios are:

- IPL Seven-Year TDSIC Risk-Based Scenario (IPL TDSIC Risk-Based Scenario) – This investment case relies on the Asset Risk Model and invests capital to replace high-risk assets and maximize risk reduction benefit per dollar invested.
- LOF 4 Scenario – This investment scenario uses an asset's expected remaining life to prioritize investments and replace, over the 7-year period, all assets that fall within the LOF 4 (High) and 5 (Very High) categories in 2026. In other words, the Asset Risk Model replaces any asset that has a LOF above 60 percent. This scenario does not consider asset consequence.
- LOF 5 Scenario – This investment scenario uses an asset's expected remaining life to prioritize investments and replace, over the 7-year period, all assets that fall within the LOF 5 (Very High) category in 2026. In other words, the Asset Risk Model replaces any asset that has a LOF above 80 percent. This scenario does not consider asset consequence. Compared to the LOF 4 scenario, the LOF 5 scenario accepts more risk while lowering the required investment.

The Risk-Based Scenario includes risk results and investment levels for the following plans of IPL's TDSIC Plan:

- Substation Assets Replacement
- Circuit Rebuilds
- 4kv Conversion
- XLPE Cable Replacement
- Remote End – Breaker Relay/Upgrades

Details on each of these scenarios are provided in the sections below.

5.2.1 4kv Conversion, XLPE Cable Replacement, and Remote End – Breaker Relay Investment Plans

Some systems within IPL's asset base require coordinated investment plans for execution. For instance, the conversion of a 4 kV system to 13.2 kV requires a detailed plan for when each circuit and substation can be retired and cut-over to the new 13.2 kV system. IPL has developed these plans for three such asset bases: 4 kV conversion to 13.2 kV, replacement of the unjacketed direct bury cable, and remote end – breaker relay upgrades project.

The Asset Risk Model is utilized to calculate the expected risk reduction of these three plans. The Asset Risk Model schedules the assets for retirement or replacement within each of these plans based on the year that IPL designated. All three investment scenarios outlined above adopt the plans for these three plans and reflect the same capital investment and risk reduction level.

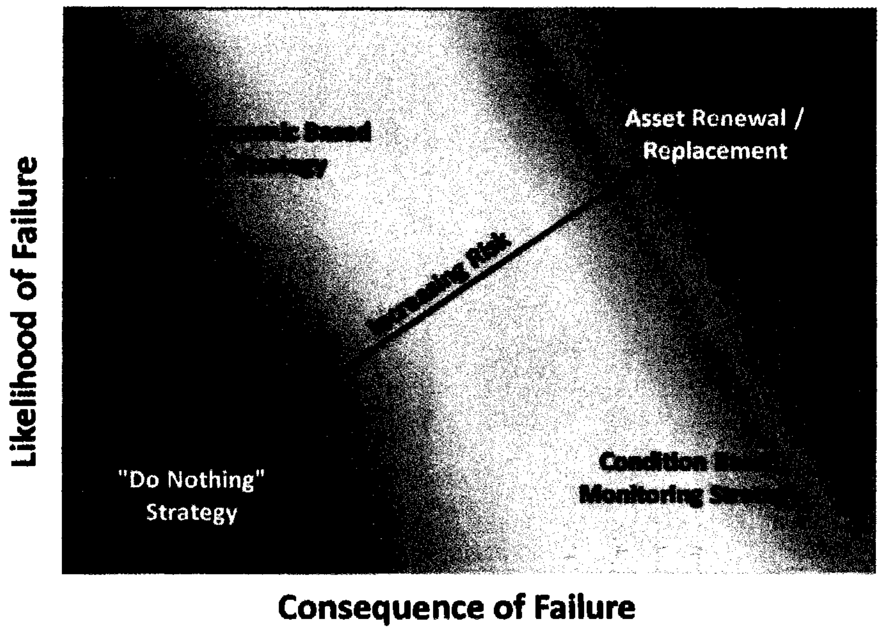
5.2.2 IPL TDSIC Risk-Based Scenario Approach

The IPL TDSIC Risk-Based Scenario utilized a risk-based planning approach to identify and prioritize the assets for replacement based on the overall budget level. Two main goals of the risk-based planning approach for IPL, as mentioned, are:

1. Identify high-risk assets and establish a plan to manage the risk.
2. Identify the highest risk reduction per dollar invested for the system.

Figure 5-1 is a guide for managing risk based on an asset's placement within the risk grid. Assets in the top-right of the grid are high-risk. The risk is managed by replacement of the asset. Assets in the bottom right of the risk grid are high consequence but are relatively healthy. The strategy for these assets is to monitor how their health changes over time. For the assets in the middle to the top left of the risk grid an economic based strategy is employed for managing risk. This means that assets can be chosen for replacement based on available funds and capital efficiency.

Figure 5-1: Risk Management Approach



Any asset with a LOF of High or greater (LOF 4 ≥ 4) and COF of High and greater (COF 4 ≥4) is a high-risk asset and required action to manage the risk. Figure 5-2 shows this region, referred to here as the High-Risk Region. In general, assets in the High-Risk Region are targeted for replacement within the 7-year period.

Figure 5-2: High-Risk Region

Likelihood of Failure	Risk Matrix				
Very High - 5				High-Risk Region	
High - 4					
Moderate - 3					
Low - 2					
Remote - 1					
	0 - 100	100 - 200	200 - 300	300 - 400	400+
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5
	Consequence of Failure				

With the identification and prioritization of the assets in the High-Risk Region, the Asset Risk Model then prioritizes investment selecting assets with the highest risk reduction per dollar invested from the Risk-Investment Efficiency Region. This approach aligns with the second of the two goals of IPL's risk-based planning approach for TDSIC noted above. Figure 5-3 and Figure 5-4 show this region substation and circuit asset bases, respectively. The larger region for the circuits' asset base is due to the nature of how circuit assets are replaced and the potential for risk reduction benefit from a consequence of failure perspective on some of the conductor types. If the area was not expanded for circuits this benefit would not have been realized.

Figure 5-3: Risk-Investment Efficiency Region for Substations

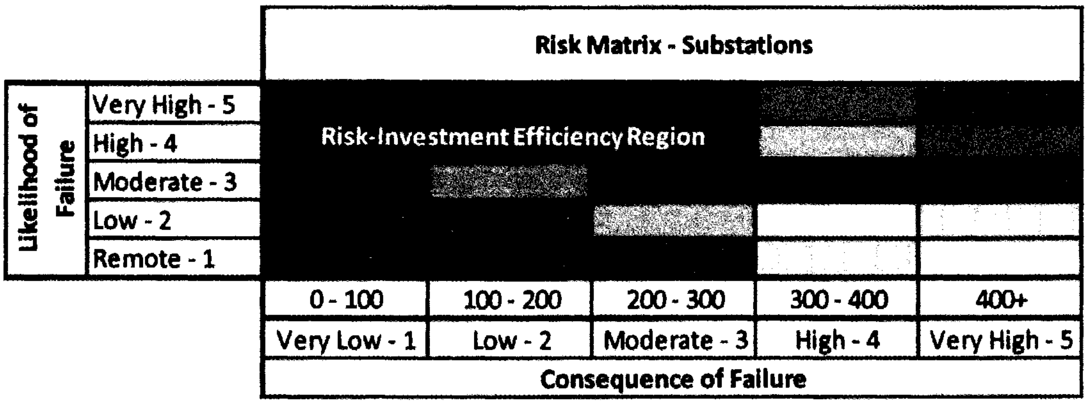
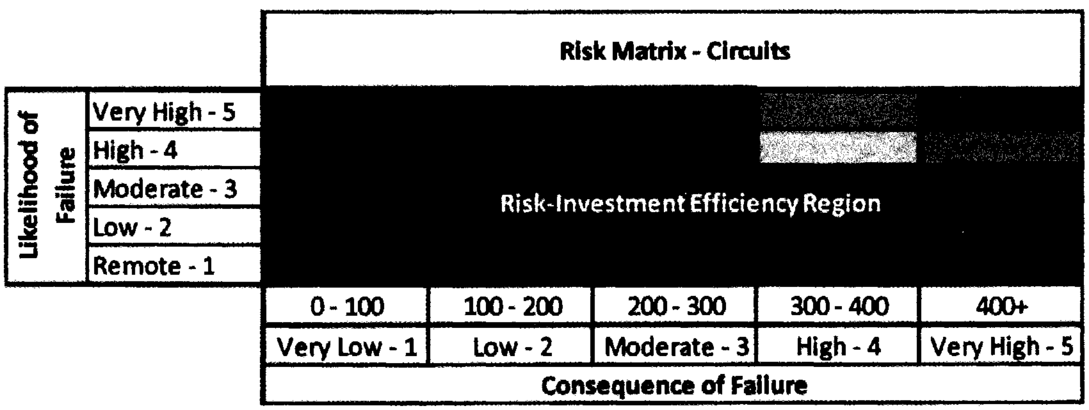


Figure 5-4: Risk-Investment Efficiency Region for Circuits



Additionally, IPL used several other factors and constraints enumerated in the summary below to identify and prioritize assets for replacement to create an executable TDSIC Risk-Based Scenario. In summary, assets were identified and prioritized for replacement based on the following:

- Overall Asset Risk, specifically those assets in the High-Risk Region.
- Risk reduction per dollar invested capital efficiency metric.
- Internal and external resources available to execute investment by asset class and by year.
- Lead time for engineering, procurement, and construction (e.g. large transformers).
- MISO and other agency coordination.
- Asset bundling into projects for work efficiencies.

- Asset replacement coordination (i.e. asset A before asset B, asset Y and asset Z at the same time).
- Asset condition and health.

5.2.3 LOF 4 Scenario Approach

The LOF 4 Scenario is intended to provide a benchmark scenario that represents the risk reduction achieved by proactively replacing old assets, regardless of COF. The LOF 4 Scenario identifies assets for replacement based expected remaining life for the asset. Specifically, the LOF 4 Scenario replaces all assets with a LOF greater than 60 percent, top two rows, by 2026 as shown in Figure 5-5. Based on the figure, the LOF 4 Scenario will replace 424 substation assets over the 7-year period. Within the 7-year period assets are bundled by substation and circuit and prioritized for replacement based on the LOF.

Figure 5-5: LOF 4 Scenario – Targeted Asset Replacements

		2026 'Do Nothing' Risk Profile Asset Count					Total
Likelihood of Failure	Very High - 5	0	2	5	[illegible]	[redacted]	200
	High - 4	[illegible]	2	4	104	[illegible]	224
	Moderate - 3	[redacted]	[illegible]	7	210	294	528
	Low - 2	[redacted]		[illegible]	122	109	243
	Remote - 1				238	244	495
	Total	1	36	25	722	906	[illegible]
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
		Consequence of Failure					

424 assets replacements in LOF 4 Scenario

The same approach is applied for the circuit assets. Any circuit segment in the LOF 4 or 5 categories by 2026 is scheduled for replacement using the same bundling approach described above. For the LOF 4 Scenario, 2,852 miles (or 99,233 segments), out of a total of 8,364 miles (or 218,175 segments), are in the LOF 4 or 5 categories. The LOF 4 Scenario replaces approximately 34 percent of the system miles or 45 percent of the system segments. It should be noted that this scenario only replaces the segments on all circuits in the LOF 4 or 5 categories, not the entire circuit.

This scenario does not consider many of the other factors and constraints of the IPL TDSIC Risk-Based Scenario noted in Section 5.2.2 above. Section 5.4 shows the results of the investment profile, heat maps post investment, and business case summary chart. It should be noted that this scenario assumes IPL can execute this level of work over the 7-year period. Further, while the IPL TDSIC Risk-Based Scenario includes a high-level schedule coordination effort, the LOF 4 Scenario does not.

5.2.4 LOF 5 Scenario Approach

The LOF 5 Scenario is intended to provide a second benchmark scenario that represents the risk reduction achieved by proactively replacing old assets, regardless of COF. The LOF 5 Scenario is like the LOF 4 Scenario in that assets are identified for replacement based on expected remaining life for the asset. In contrast, the LOF 5 Scenario replaces all the assets by 2026 that have a LOF greater than 80 percent, whereas the LOF 4 Scenario uses a 60 percent threshold for LOF.

Figure 5-6 shows that the LOF 5 Scenario includes the replacement of 200 substation assets. On the circuit side, the LOF 5 Scenario includes the replacement of 1,762 miles (or 64,628 segments), out of a total of 8,364 miles (or 218,175 segments). The LOF 5 Scenario replaces approximately 21 percent of the system miles or 30 percent of the system segments. It should be noted that this scenario only replaces the segments on all circuits in the LOF 5 category, not the entire circuit.

Figure 5-6: LOF 5 Scenario – Targeted Asset Replacements

	2026 'Do Nothing' Risk Profile Asset Count					Total
Likelihood of Failure	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
Very High - 5	0	2	5	[redacted]	[redacted]	200
High - 4	[redacted]	2	4	104	[redacted]	224
Moderate - 3	[redacted]	[redacted]	7	210	294	528
Low - 2	[redacted]	[redacted]	1	122	109	243
Remote - 1	[redacted]	[redacted]	[redacted]	238	244	495
Total	1	36	25	722	906	[redacted]

Consequence of Failure

200 asset replacements in LOF 5 Scenario.

As noted above, this investment scenario replaces the 4 kV and unjacketed underground assets per the plans established by IPL. This scenario does not consider many of the other factors and constraints of the IPL TDSIC Risk-Based Scenario noted in Section 5.2.2 above. Section 5.3 shows the results of the investment profile, heat maps post investment, and business case summary chart. It should be noted that this scenario assumes IPL can execute this level of work over the 7-year period. Further, while the IPL TDSIC Risk-Based Scenario includes a high-level schedule coordination effort, the LOF 5 Scenario does not.

5.3 IPL TDSIC Risk-Based Scenario Results

This section shows the investment plan, risk heat maps after investment, and business case summary results for the IPL TDSIC Risk-Based Scenario. The approach to selecting the assets and prioritizing for replacement is outlined in Section 5.2.2 above.

5.3.1 IPL TDSIC Risk-Based Scenario Investment Results

Table 5-1 shows the asset replacement schedule throughout the 7-year TDSIC period for the IPL TDSIC Risk-Based Scenario. In total, there are 825 substation asset replacements or retirements and 1,291 section miles of circuits replaced or retired.

Table 5-1: Investment Scenario Replacement Schedule

Asset Category	Units	2020	2021	2022	2023	2024	2025	2026	Total
Power Transformer	[count]	6	5	1	4	7	3	10	36
Breaker	[count]	54	99	114	139	99	110	89	704
Battery	[count]	29	11	15	10	6	5	9	85
Trans + Sub-T	[miles]	0	0	0	0	0	0	0	0
OH - T&D Section	[miles]	69	52	84	95	74	81	72	527
UG Primary	[miles]	109	109	109	109	109	109	109	764

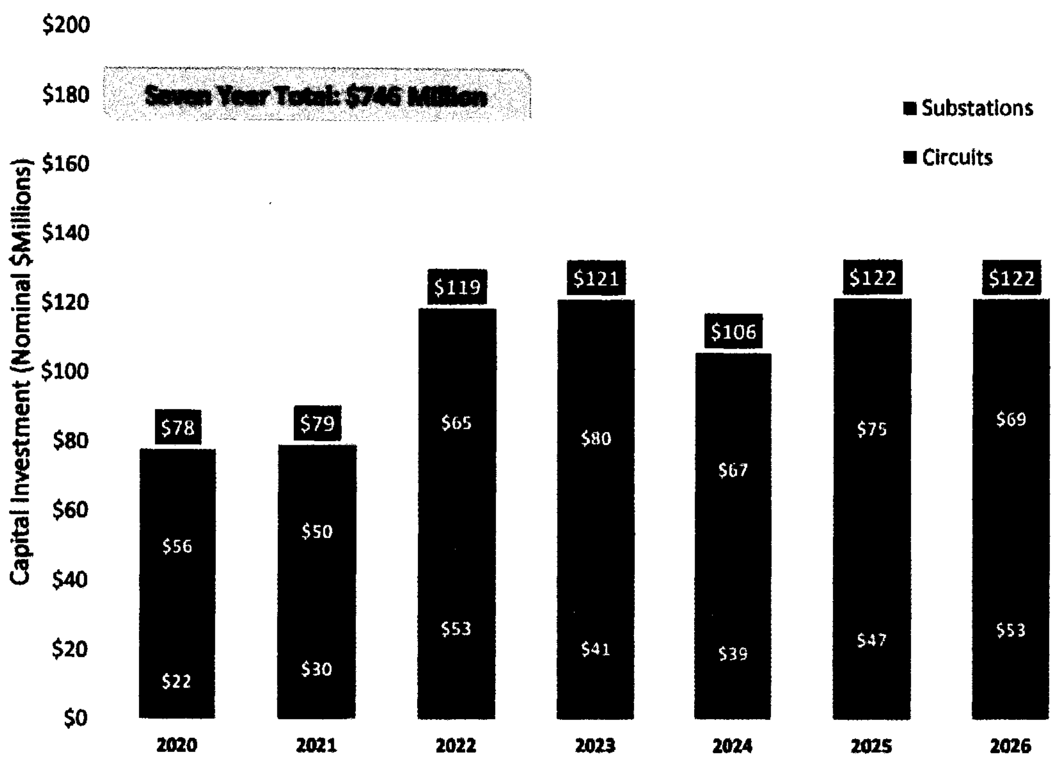
Table 5-2 shows the 7-year total investment by Project Plan category for the asset replacements and retirements shown above.

Table 5-2: IPL TDSIC Risk-Based Scenario Investment Summary

Project Plan	Nominal $millions
4kv Conversion	$92.0
XLPE Cable Replacement	$86.2
Remote End – Breaker Relay / Upgrades	$21.0
Substation Assets Replacement	$248.1
Circuit Rebuilds	$298.7

Figure 5-7 displays the annual capital investment profile of the IPL TDSIC Risk-Based Scenario totaling $746 million. The annual variability is driven by the bundling of assets into projects. The numbers in the chart include investment for the 4 kV conversion, unjacketed replacement plan, breaker remote end and relay project, and the asset replacements identified by the Asset Risk Model. The spend levels for the substation asset replacements and circuit upgrades are based on IPL technical internal limits over the 7-year period.

Figure 5-7: IPL TDSIC Risk-Based Scenario Investment Profile



5.3.2 IPL TDSIC Risk-Based Scenario Risk Results Summary

Section 4.3 includes the heat maps for the substation asset and circuit counts and risk scores for the 'Do Nothing' scenario. The following two figures, Figure 5-8 and Figure 5-9, show the heat maps in 2026 after investment for substations and circuits respectively. The total asset and circuit counts in the figures differ from those in Section 4.3 because of the 4 kV conversion asset retirements.

For the substation assets, IPL's TDSIC Risk-Based Scenario replaces or retires all the assets in the High-Risk Region, it also captures many of the assets immediately outside of the High-Risk Region. The resulting substation system risk in 2026 from the scenario is approximately 147,000, 64.4 percent decrease in risk compared to the 2026 'Do Nothing' scenario.

For the circuit asset base results, shown in Figure 5-9, the resulting system risk in 2026 is approximately 2,692,000, 33.8 percent decrease in risk compared to the 2026 'Do Nothing' scenario. Further the plan removes 124 circuits from the High-Risk Region leaving 23 circuits. Compared to the 2026 'Do Nothing' scenario the plan reduced risk in the High-Risk Region by 93.6 percent to an overall risk level of approximately 95,000. It should be noted that IPL's technical execution limit over the 7 years does not allow them to replace all the sections in the High-Risk Region, causing 23 circuits to remain in the High-Risk Region after 2026. As discussed above, COF typically remains constant over time, but for some asset classes the COF does change with a near 'in-kind' replacement. In the case of the circuit upgrades, some wire types (covered conductor) consequence scores decreased with the replacement to the new equipment standard (bare conductor). This is the reason for circuits moving to lower COF categories.

Figure 5-8: 2026 Substation IPL TDSIC Risk-Based Scenario Asset Count

Likelihood of Failure	2026 Investment Plan Risk Profile Asset Count					Total
Very High - 5	0	1	0	[illegible]	[illegible]	1
High - 4	[illegible]	0	1	0	[illegible]	1
Moderate - 3	[illegible]	[illegible]	3	90	87	186
Low - 2	[illegible]	[illegible]	2	116	146	271
Remote - 1	[illegible]	[illegible]	[illegible]	416	633	1,062
Total	1	17	15	622	866	[illegible]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure					

0 assets, or 0%, in High-Risk Region.

Figure 5-9: 2026 Circuit IPL TDSIC Risk-Based Scenario Circuit Count

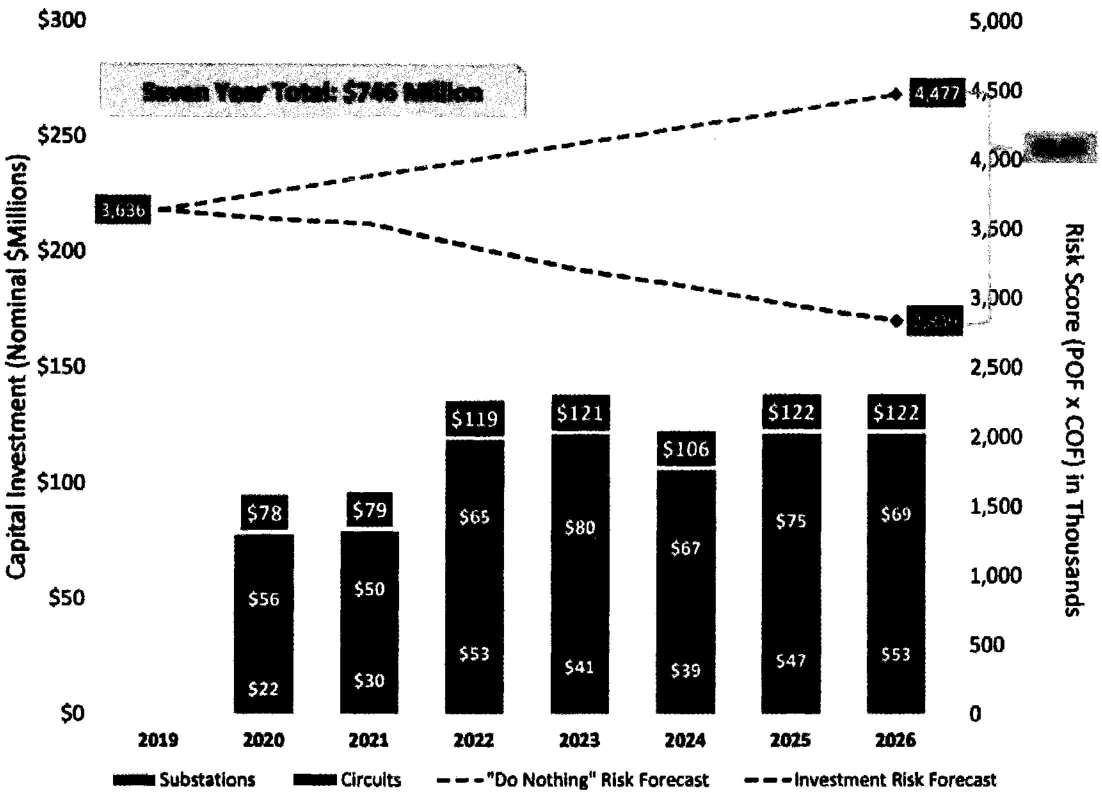
Likelihood of Failure	2026 Investment Plan Risk Profile Circuit Count					Total
Very High - 5	0	0	0	[illegible]	[illegible]	3
High - 4	[illegible]	0	0	0	[illegible]	20
Moderate - 3	[illegible]	[illegible]	3	2	178	183
Low - 2	[illegible]	[illegible]	2	19	286	308
Remote - 1	[illegible]	[illegible]	[illegible]	1	62	68
Total	0	5	6	23	548	[illegible]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure per Mile					

23 circuits, or 4%, in High-Risk Region.

5.3.3 IPL TDSIC Risk-Based Scenario Business Case Summary Results

Figure 5-10 shows the overall business case comparing risk reduction to invested capital for the IPL TDSIC Risk-Based Scenario.

Figure 5-10: IPL TDSIC Risk-Based Scenario Capital Investment vs. Risk Profile



The following highlights some of the main business case points for the IPL TDSIC Risk-Based Scenario:

- Total risk reduction by the end of 2026 (year 7) of 36.6 percent.
- Replacement or retirement of 825 substation assets ($285 million) and 1,291 section miles of circuits ($461 million) for total for investment in capital of $746 million.
- Mitigation of all substation asset risk in the High-Risk Region. In the High-Risk region, 40 circuits remain due to IPL's technical constraints for circuit upgrades over the 7-year period.
- For every million dollars invested, risk is reduced by 2,196 risk points.

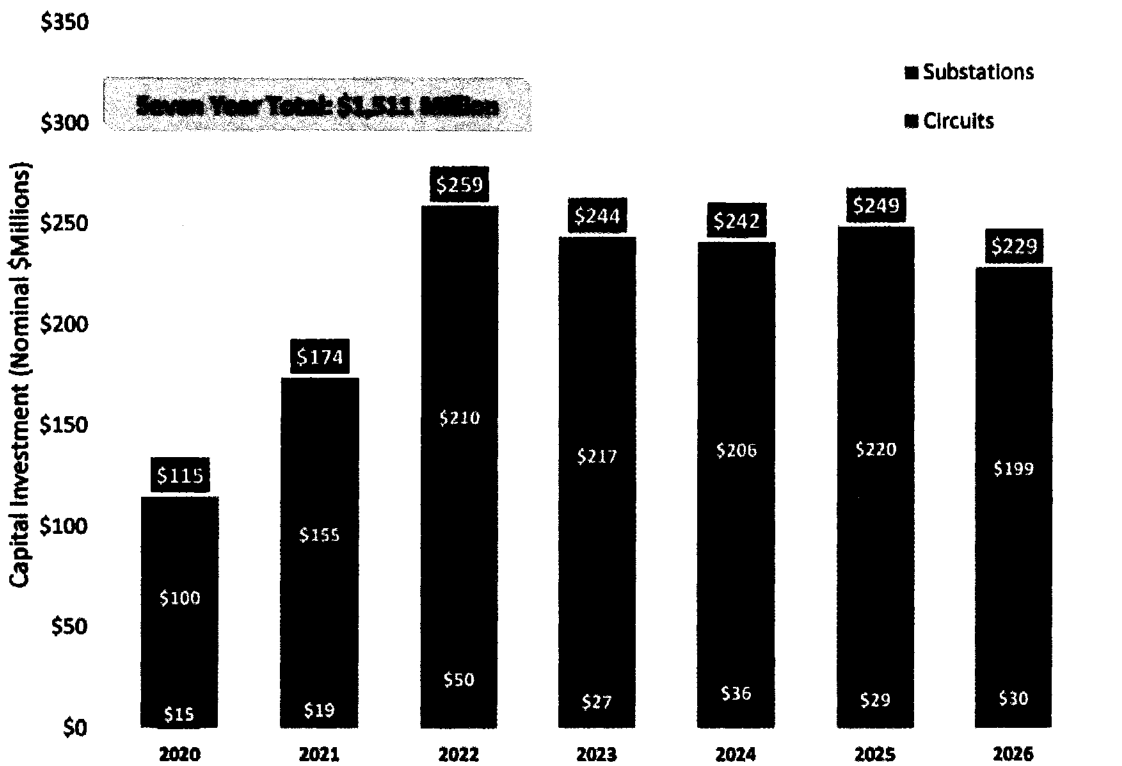
5.4 LOF 4 Scenario Results

This section shows the investment plan, risk heat maps after investment, and business case summary results for the LOF 4 Scenario. The approach to selecting the assets and prioritizing for replacement is outlined in Section 5.2.3. At a high level, the LOF 4 plan replaces all assets with a LOF of 60 percent and greater.

5.4.1 LOF 4 Scenario Investment Plan Results

Figure 5-11 displays the annual capital investment profile of the LOF 4 Scenario totaling $1,511 million. The numbers in the chart include investment for the 4 kV conversion, unjacketed replacement plan, breaker remote end and relay project, and the asset replacements identified by the Asset Risk Model. Substation total spend is approximately $206 million, while total spend for circuits is approximately $1,306 million. In total, there are 488 substation asset replacements or retirements and 3,136 section miles of circuits replaced or retired. Based on IPL's and external contractor's execution capacity, the plan is likely executable on the substation side, however the circuit plan is likely not executable.

Figure 5-11: LOF 4 Scenario Investment Profile



5.4.2 LOF 4 Scenario Risk Results Summary

Section 4.3 includes the heat maps for the substation asset and circuit counts and risk scores for the 'Do Nothing' scenario. The following two figures, Figure 5-12 and Figure 5-13, show the heat maps in 2026 after investment for substations and circuits respectively. The total asset and circuit counts in the figures differs from those in Section 4.3 because of the 4 kV conversion asset retirements. With the significant higher asset replacement levels, especially for the circuit assets, the total risk reduction is significantly more than the IPL TDSIC Risk-Based Scenario. The total risk of the substation asset base after investment is approximately 214,000 and approximately 2,159,000 for the circuit asset base for a combined system risk of 1,473,000 post investment. This is a decrease in risk compared to the 2026 'Do Nothing' scenario of 48.1 percent and 69.0 percent for substations and circuit, respectively, and 67.1 percent overall.

Figure 5-12: 2026 Substation LOF 4 Scenario Asset Count

Likelihood of Failure	2026 Investment Plan Risk Profile Asset Count					Total
Very High - 5	0	0	0	[illegible]	[illegible]	0
High - 4	[illegible]	0	0	0	[illegible]	0
Moderate - 3	[illegible]	6	3	203	267	479
Low - 2	[illegible]	[illegible]	5	119	153	283
Remote - 1	[illegible]	[illegible]	[illegible]	299	447	759
Total	1	17	15	621	867	[illegible]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure					

0 assets, or 0%, in High-Risk Region.

Figure 5-13: 2026 Circuit LOF 4 Scenario Circuit Count

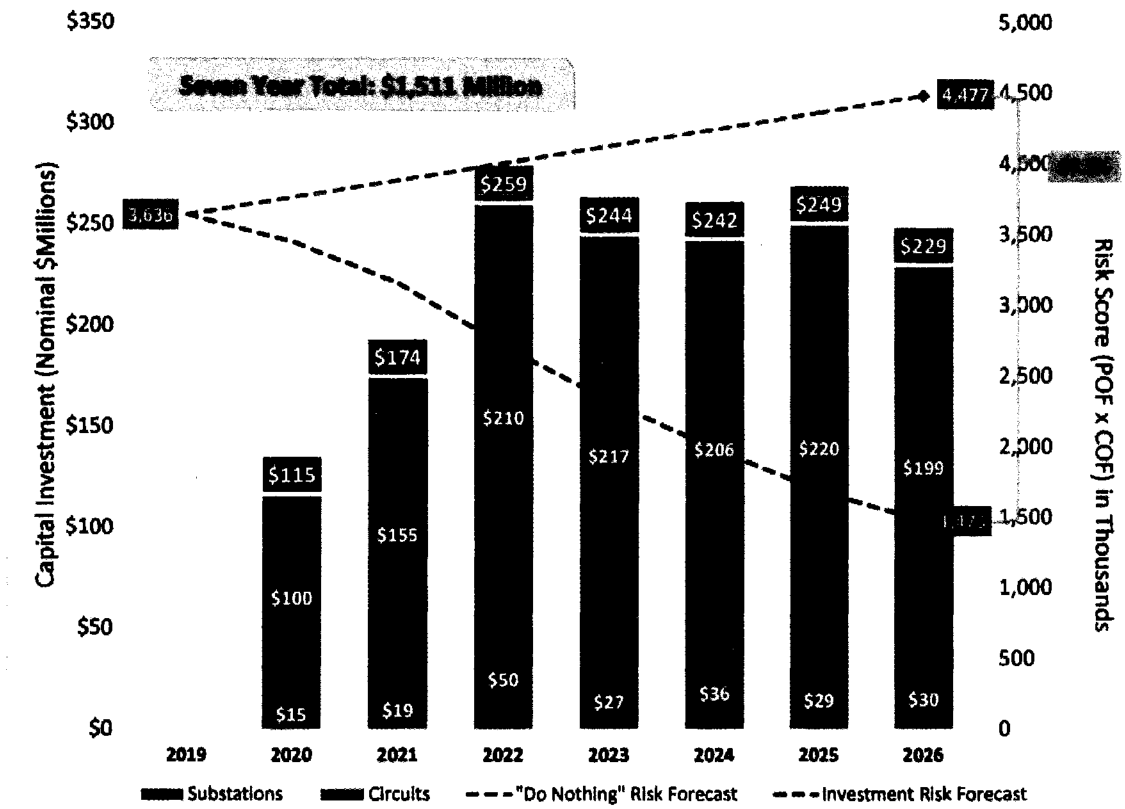
Likelihood of Failure	2026 Investment Plan Risk Profile Circuit Count					Total
Very High - 5	0	0	0	[illegible]	[illegible]	0
High - 4	[illegible]	0	0	0	[illegible]	0
Moderate - 3	[illegible]	[illegible]	3	0	36	39
Low - 2	[illegible]	[illegible]	2	16	179	198
Remote - 1	[illegible]	[illegible]	[illegible]	9	330	345
Total	0	5	7	25	545	[illegible]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure per Mile					

0 circuits, or 0%, in High-Risk Region.

5.4.3 LOF 4 Scenario Business Case Summary Results

Figure 5-14 shows the overall business case comparing risk reduction to invested capital for the LOF 4 Scenario.

Figure 5-14: LOF 4 Scenario Capital Investment vs. Risk Profile



The following highlights some of the main business case points for the LOF 4 Scenario:

- Total risk reduction by the end of 2026 (year 7) of 67.1 percent.
- Replacement or retirement of 488 substation assets (approximately $206 million) and 3,136 section miles of circuits (approximately $1,306 million) for a total investment in capital of approximately $1,516 million.
- No assets remaining in the High-Risk Region.
- Risk points reduced per million dollars invested of 1,988.

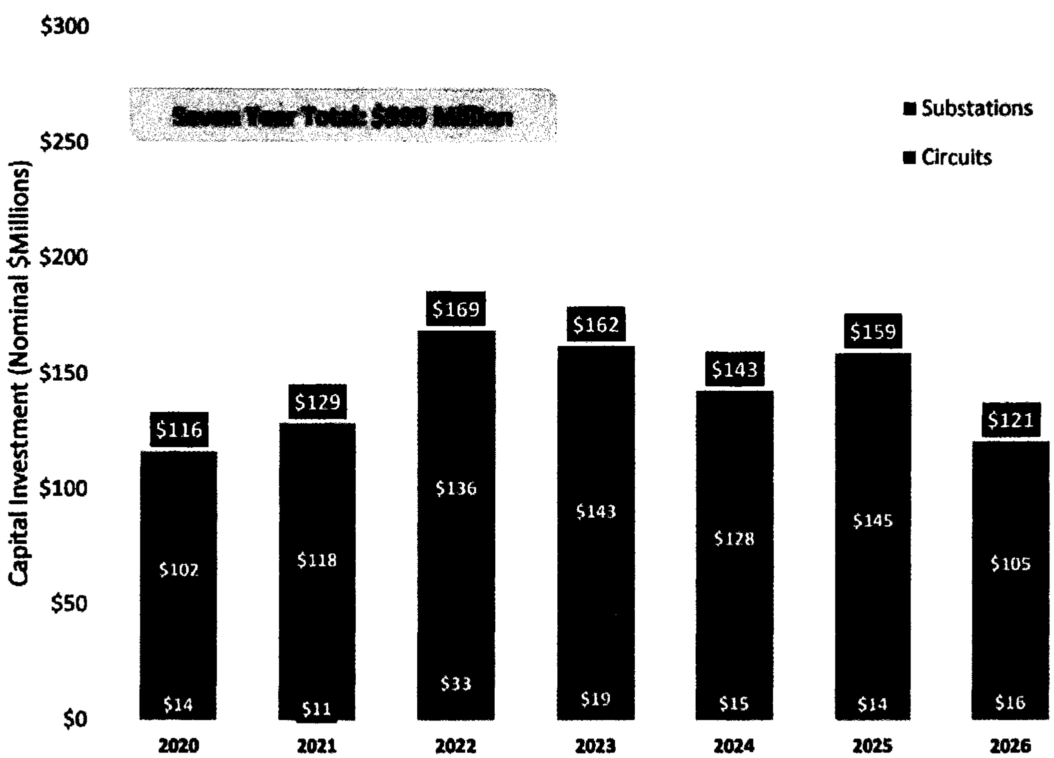
5.5 LOF 5 Scenario Results

This section shows the investment plan, risk heat maps after investment, and business case summary results for the LOF 5 Scenario. The approach to selecting the assets and prioritizing for replacement is outlined in Section 5.2.4 above. At a high level, the LOF 5 Scenario replaces all assets with a LOF of 80 percent and greater.

5.5.1 LOF 5 Scenario Investment Plan Results

Figure 5-15 displays the annual capital investment profile of the LOF 5 Scenario totaling $999 million. The numbers in the chart include investment for the 4 kV conversion, unjacketed replacement plan, breaker remote end and relay project, and the asset replacements identified by the Asset Risk Model. Substation total spend is approximately $122 million while circuit total spend is approximately $877 million. In total, there are 328 substation asset replacements or retirements and 2,332 section miles of circuits replaced or retired. While the plan is executable on the substation side, the circuit plan is likely not executable.

Figure 5-15: LOF 5 Scenario Investment Profile



5.5.2 LOF 5 Scenario Risk Results Summary

Section 4.3 includes the heat maps for the substation asset and circuit counts and risk scores for the 'Do Nothing' scenario. The following two figures, Figure 5-16 and Figure 5-17, show the heat maps in 2026 after investment for substations and circuits respectively. The total asset and circuit counts in the figures differs from those in Section 4.3 because of the 4 kV conversion asset retirements. With the significant higher number of asset replacements, the total risk reduction is significantly more than the IPL TDSIC

Risk-Based Scenario. The total risk of substation asset base after investment is approximately 265,000 and approximately 2,137,000 for the circuit asset base for a combined system risk of 2,402,000 post investment. This is a decrease in risk compared to the 2026 'Do Nothing' scenario of 35.6 percent and 47.4 percent for substations and circuit, respectively, and 46.4 percent overall.

Figure 5-16: 2026 Substation LOF 5 Scenario Asset Count

		2026 Investment Plan Risk Profile Asset Count					Total
Likelihood of Failure	Very High - 5	0	0	0	[illegible]	[illegible]	0
	High - 4	[illegible]	0	1	57	[illegible]	160
	Moderate - 3	[illegible]	[illegible]	3	203	267	479
	Low - 2	[illegible]	[illegible]	2	119	157	286
	Remote - 1	[illegible]	[illegible]	[illegible]	241	342	596
	Total	1	17	15	620	868	[illegible]
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
		Consequence of Failure					

159 assets, or 10%, in High-Risk Region.

Figure 5-17: 2026 Circuit LOF 5 Scenario Miles Count

		2026 Investment Plan Risk Profile Circuit Count					Total
Likelihood of Failure	Very High - 5	0	0	0	[illegible]	[illegible]	0
	High - 4	[illegible]	0	0	0	[illegible]	5
	Moderate - 3	[illegible]	[illegible]	3	0	77	80
	Low - 2	[illegible]	[illegible]	3	18	418	440
	Remote - 1	[illegible]	[illegible]	[illegible]	3	49	57
	Total	0	5	7	21	549	[illegible]
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
		Consequence of Failure per Mile					

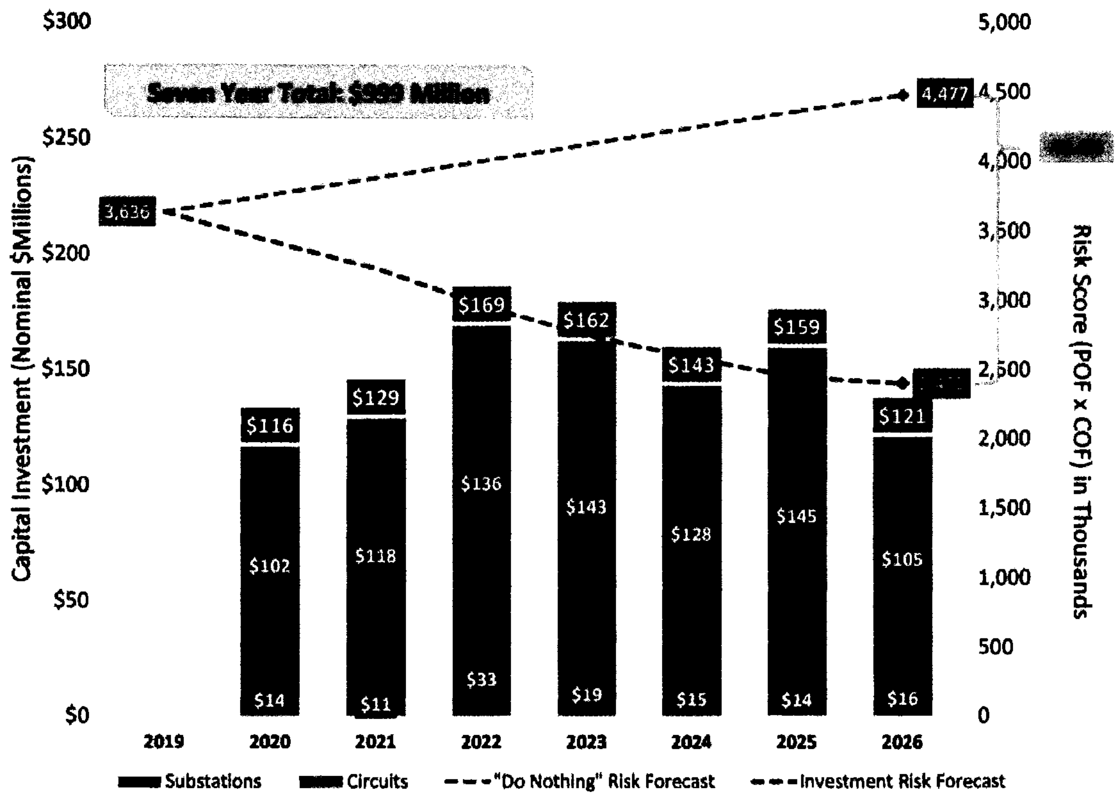
5 circuits, or 1%, in High-Risk Region.

For the substation asset base, before investment, the High-Risk Region included 411 assets (Figure 4-4) with a total risk score of approximately 212,000. After the LOF 5 Scenario, 159 assets remain in the High-Risk Region. Those 159 assets have a risk score of approximately 57,000. The Risk-Based Scenario replaces all substation assets in the High-Risk Region. Figure 5-17 shows that the LOF 5 Scenario removes most of the circuits from the High-Risk Region.

5.5.3 LOF 5 Scenario Business Case Summary Results

Figure 5-18 shows the overall business case comparing risk reduction to invested capital for the LOF 5 Scenario.

Figure 5-18: LOF 5 Investment Plan Capital Investment vs. Risk Profile



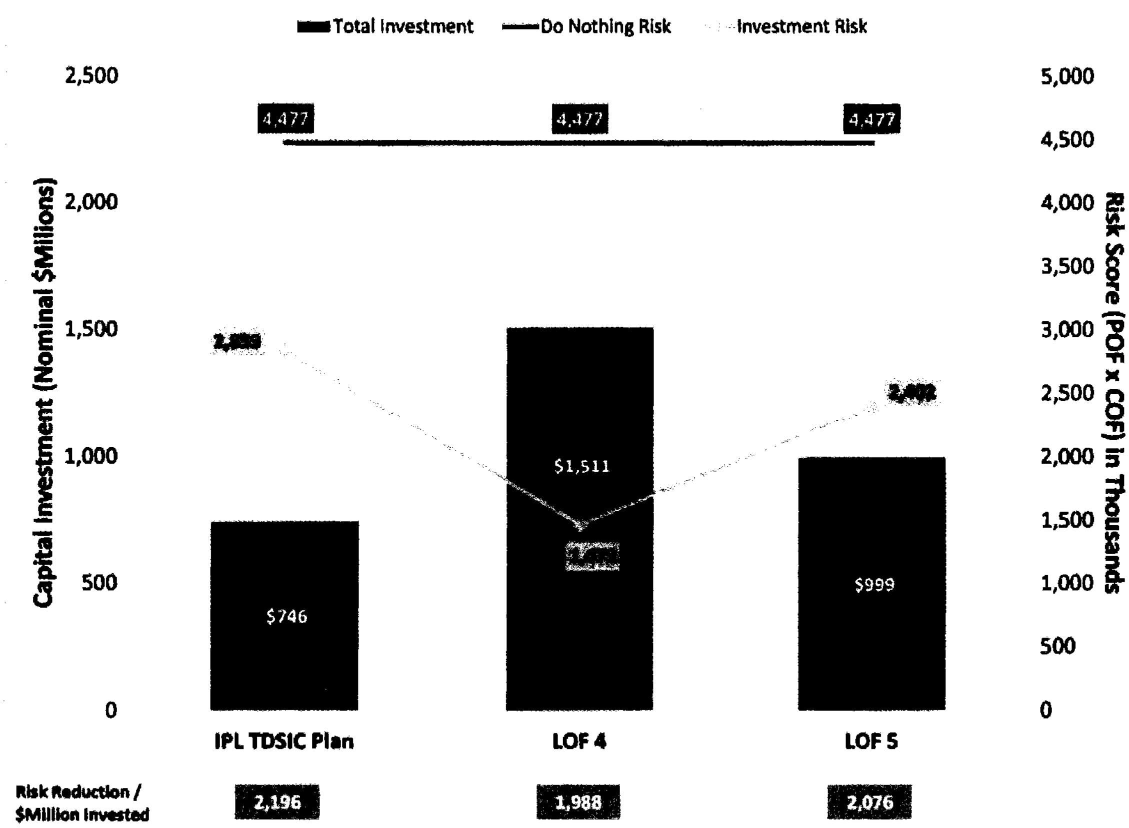
The following highlight some of the main business case points for the LOF 5 Scenario:

- Total risk reduction by the end of 2026 (year 7) of 46.4 percent.
- Replacement or retirement of 328 substation assets (approximately $122 million) and 2,332 section miles of circuits (approximately $877 million) for a total investment in capital of approximately $999 million.
- 159 substation assets and 5 circuits remain in the High-Risk Region.
- Risk reduced per million dollars invested of 2,076.

5.6 Investment Scenarios Summary Results

Figure 5-19 summarizes the three investment plan business cases. The figure is a summary and comparison of the results shown above in Sections 5.3, 5.4, and 5.5. The red line represents the 'Do Nothing' risk results while the green line represents the 2026 risk score of each scenario investment plan. The blue bars show the total 7-year investment for each scenario. The orange box shows the risk reduction per million dollars invested, a measure of the investment scenarios capital efficiency.

Figure 5-19: Scenario Risk and Investment Summary Results



The figure and sections above show the following:

- The age-based investment scenarios LOF 4 and LOF 5 require more capital investment than the IPL TDSIC Plan scenario, $765 million and $253 million more for LOF 4 and LOF 5 scenarios, respectively.
- The IPL TDSIC Plan has the highest risk reduction efficiency of 2,196
- The IPL TDSIC Plan scenario replaces all the substation assets in the High-Risk Region. While the IPL TDSIC Plan does not remove all the circuits from the High-Risk Region, this is due to

technical execution constraints. The LOF 4 plan removes all the substation assets from the High-Risk Region while the LOF 5 plan still has 159 assets. The LOF 4 and LOF 5 scenarios remove all or nearly all the circuits from the High-Risk Region.

- The IPL TDSIC Plan incorporates the other factors and constraints identified in Section 5-2 (e.g. project coordination, MISO outages, contractor limits) to execute investments over the 7-year period.
- While the LOF 4 and LOF 5 scenarios have more risk reduction than the IPL TDSIC Plan scenario, they come at a significantly higher cost and lower risk reduction per dollar invested. The LOF 4 and LOF 5 scenario capital efficiencies (1,988 and 2,076, respectively) are less than that of the IPL TDSIC Plan (2,196).

As discussed throughout the report, IPL utilized a risk-based planning approach in creating a 7-year TDSIC capital plan with the goal of managing high-risk assets and providing economic risk reduction. The IPL TDSIC plan manages the risk with all the assets in the High-Risk Region up to IPL's technical executable constraints, while achieving the highest capital efficiency and spending less than the LOF 4 and LOF 5 scenarios.

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Appendix 8.4 Black & Veatch Review of the Burns & McDonnell Risk Model

BLACK & VEATCH REVIEW OF THE BURNS & MCDONNELL RISK MODEL

B&V PROJECT NO.400364

PREPARED FOR

Indianapolis Power & Light Company (IPL)

JULY 2019

BLACK & VEATCH

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1.0 Overview

During Q4 2018 Black & Veatch was commissioned by Indianapolis Power & Light ("IPL") to conduct an inspection and review of the IPL Transmission and Distribution System Asset Risk Model ("Risk Model") that was developed by Burns & McDonnell ("BMcD"). This model is a MS Excel-based planning and diagnostic tool. IPL uses the Risk Model to parameterize, gauge and measure certain risk attributes related to the IPL Transmission and Distribution ("T&D") system. This model is the joint property of BMcD and IPL. IPL commissioned BMcD to assemble IPL transmission and distribution system asset data, inspect and format the data and apply it to the Risk Model. BMcD and IPL developed input assumptions required by the model that relate to asset failure impacts and other various parameters characterizing the likelihood of asset failures.

The purpose of this memorandum is to explain Black & Veatch's review of the Risk Model and provide Black & Veatch's observations about it. IPL requested that Black & Veatch inspect and review the Risk Model for general soundness in relation to certain practice norms, inspect the inputs that have been used, and to validate that the model yields reasonable outputs given the nature of the applied inputs.[1]

2.0 Qualifications

IPL selected Black & Veatch to perform this review because of Black & Veatch's independence in this matter and its asset management consulting practice qualifications and capabilities in general. Black & Veatch also has specific experience related to the Indiana Transmission, Distribution and Storage System Improvement Charge ("TDSIC") plan development process and evaluation norms associated with it.

Specifically, Black & Veatch uses and deploys similar asset registry and risk models in its work with electric and gas utilities for similar risk attribute assessments that were conducted for IPL by BMcD. Black & Veatch is highly familiar with the use, construction and operation of asset registries and risk models. Black & Veatch's consultants are also leaders in applying industry practice norms related to asset management assessments. These involve application of the International Organization for Standardization ("ISO") standards and guidelines to gather and apply asset performance data and to measure and quantify risk in relation to and arising from this data.[2] This expertise in applying essential asset management practice norms greatly influence the nature of the review.

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[1] IPL requested that Black & Veatch and BMcD work collaboratively to conduct this inspection and review of the Risk Model. In fact, the success of this effort was only possible through the collaboration of BMcD, IPL and Black & Veatch in this matter.

[2] Black & Veatch's extensive experience includes asset management planning, capital prioritization, asset failure analysis, risk assessment using the International Organization for Standardization standard for risk management (ISO31000), performance benchmarking, maintenance optimization, business planning, serviceability assessment, whole life costing, operational efficiency, International Organization for Standardization standard for asset management maturity assessments (ISO55001), business change management, and infrastructure rehabilitation.

3.0 Scope Definition and Purposes

To conduct this Risk Model inspection and review, Black & Veatch carried out the following activities. The purposes of each activity is also described.

Black & Veatch:

1) Inspected the MS Excel-based computer spreadsheet Risk Model's "architecture". This means the structure of the spreadsheet model and how parts of the model interact to translate inputs to outputs.

2) Inspected certain formulas used in the Risk Model through in person and web-based meetings. The inspections were limited to formulas that BMcD considered non-proprietary. Also, this step was conducted on a sampling basis. For those formulas that were considered proprietary, Black & Veatch and BMcD discussed their purposes and principles for 'reasonableness'.

3) Inspected some data sets that were provided by IPL and then applied within the Risk Model. This too was conducted on a sampling basis.

4) Reviewed a set of Risk Model input assumptions, including unit cost data, asset depreciation curves from IPL's most recent depreciation study, and criticality criteria from IPL's Asset Management system. This step was conducted on a sampling basis as well. However, the most impactful assumptions (in Black & Veatch's judgment) were included in this review.

5) Inspected the assumptions that BMcD applied to the Risk Model that involve broad adjustments to classes of data and/or other input assumptions. This constitutes both informal or formal "rules" by the model analyst that ostensibly could play a role in influencing the input data (and therefore final model evaluation outputs, and potentially conclusions). This step includes the method used to adjust the actual asset ages to determine effective ages, and 'scoring approaches' for assessing the risk of asset classes.

6) Inspected the Risk Model results (i.e., outputs) in the form of tabular data and graphs.

The intention of the work was not to conduct a detailed audit of the Risk Model. In fact, in performing this work Black & Veatch inspected the model, formulas, input assumptions, and data sets, informal sampling techniques, and informal questioning of BMcD model users.

IPL commissioned Black & Veatch to provide a check on the **soundness** of the model (architecture, methods, data inputs, computations, outputs) in relation to asset practice norms , and to identify and describe for reasonableness unexpected or uncommon elements of the Risk Model in relation to generating outputs (which in turn support the rendering of conclusions) regarding the risk attributes of the IPL T&D system assets. The six (6) activities identified above represent means towards these ends and are described further in Table 3-1.

Table 3-1 B&V Review and Inspection Scope

WORK AREA	OBJECTIVE	SCOPE	LIMITATIONS
Inspected Risk Model "architecture"	Model architecture inspected for conformance with Asset Management norms (per practice norms in Indiana and elsewhere and ISO 31000 and 55000 standards)	B&V model inspection of model architecture and core modules and essential functionality	Formulas and model logic deemed as proprietary were verbally discussed only with BMcD.
Inspected formulas	Inspected model formulas in meetings and spot checked (sampled) the use of depreciation curves for breakers	Spot check of some formulas through re-creating the development of likelihood of failure calculations for breakers	Proprietary model was not provided to Black & Veatch so spot check was done by re-creating likelihood of failure calculations for breakers
Inspected data sets	Inspected data IPL provided to BMcD for completeness and to understand how BMcD modified source data[3] for the Risk Model	This included unit cost data, asset depreciation curves from IPL's most recent depreciation study, condition data and scoring, and criticality criteria from IPL's Asset Management system.	
Reviewed input assumptions	Inspected input assumptions through face to face and web meetings	This included: • unit cost data • asset depreciation curves from IPL's most recent depreciation study • criticality criteria from IPL's Asset Management system	Since the proprietary model was not provided to Black & Veatch, the model was inspected through face to face and web meetings
Inspected "rules" that influence model	Inspected model rules through face to face and web meetings	This included: • infilling of missing age data • effective age adjustments • consequence of failure scoring rules	Since the proprietary model was not provided to Black & Veatch, the model was inspected through face to face and web meetings
Inspected Risk Model Results	Inspected model outputs through face to face and web meetings	Reviewed Risk Model output for reasonableness	Since the proprietary model was not provided to Black & Veatch, the model was inspected through face to face and web meetings

[3] Data is often modified to address errors and gaps in the data and to format it and otherwise prepare it for use in the model. Often poor data is eliminated for further use. Sometimes modelers use the phrase "scrub the data" to describe these steps. Scrubbing the data improves the model's quality by improving the integrity of the data that is eventually applied within the model.

4.0 Black & Veatch Review Method

To perform this work Black & Veatch conducted several meetings with BMcD and IPL so the BMcD team members could explain to Black & Veatch how the Risk Model was developed, how the input assumptions were derived, how missing input data was infilled,[4] how model formulas operate, and how results were generated and interpreted.

Because of the proprietary nature of the Risk Model, Black & Veatch was not provided a copy of the Risk Model for independent audit and review. Rather, during the meetings BMcD demonstrated and discussed the model in a logical step-wise fashion. Separate and apart from these meetings Black & Veatch re-created the BMcD model likelihood of failure calculation for transmission system breakers and compared these results to a summary table from the BMcD model. Transmission system breakers were selected for this step because they are a large and important asset class. Black & Veatch also reviewed BMcD-created documentation explaining the Risk Model architecture, inputs and outputs.

Additionally, as part of the inspection and review of the Risk Model attributes (inputs, outputs, and computational 'engine'), Black & Veatch levered its experience with similar risk modeling exercises. Using public domain information, specific areas of review include:

- ISO-based Risk Framework (meaning the way in which risk is measured and assets compared)
- Average service life data by asset class
- Depreciation curves by asset class
- Model Output

5.0 Risk Model Description

The goal of using the Risk Model is to determine a way to focus on high-risk assets for priority replacement. This is done by quantifying the risk reduction achieved by investing in the replacement of certain assets whose risk score is in the higher risk regions of the heat map. The quantification is the product of the consequence of an asset's failure and its likelihood of failure. The assets with a higher consequence and likelihood of failure pose a higher risk to IPL's T&D system. Once the Risk Model was developed, it was then used by BMcD to help IPL identify the capital expenditures for substations and circuits that were part of IPL's TDSIC filing. IPL used their engineering judgement to determine the amount of work that was able to be completed in a seven-year period and then the Risk Model identified the assets for replacement.

[4] This activity is common when working with large data sets. The primary method for infilling was using the install year from other assets that were in close proximity. An example is using the install year of a pole for conductor.

6.0 Black & Veatch Inspection and Review of Risk Model Architecture

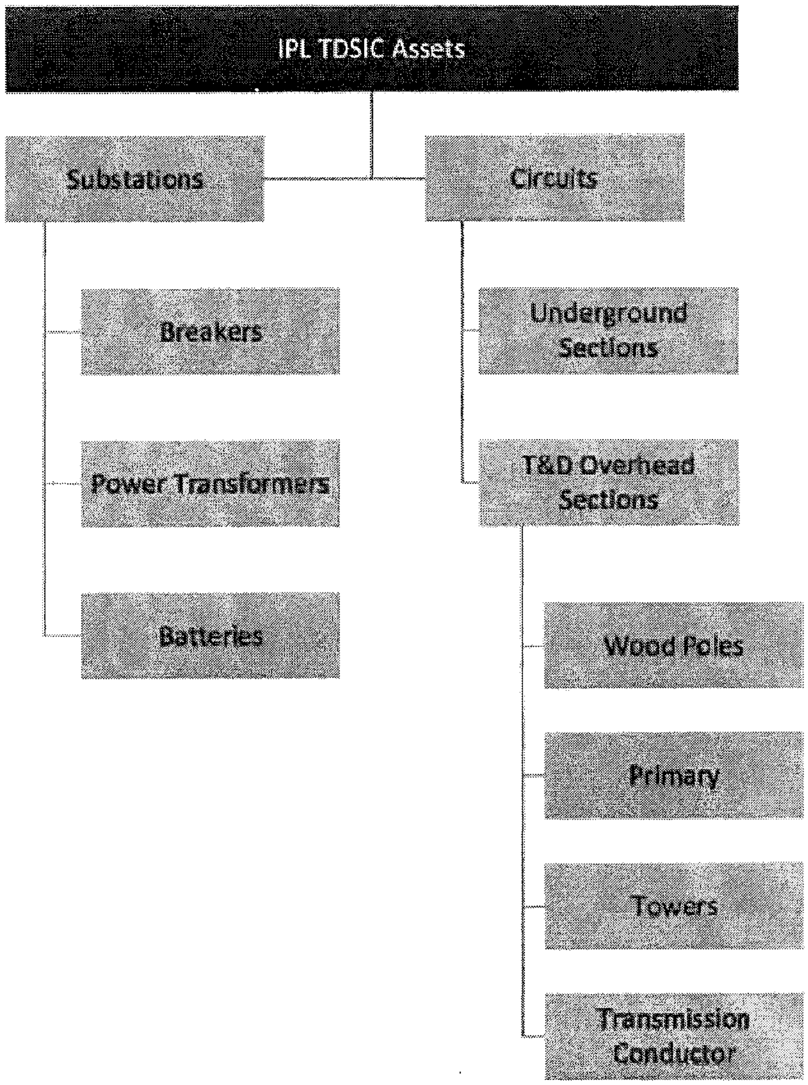
Black & Veatch used its knowledge of Asset Management norms (practice norms in Indiana and elsewhere and ISO 55000 standards) to inspect the Risk Model architecture. This was completed through face to face and web meetings as noted earlier. BMcD broadcasted the MS Excel model to the meeting participants, reviewing and explaining the model architecture. The modules depicted in Figure 6-1 were included in this review. The exception was the Geodatabase which was explained as propriety to BMcD. However, BMcD and its Geodatabase expert explained the way in which the database was developed and how and where the source data was acquired.

During these meetings Black & Veatch requested deeper explanations when the architecture deviated from other models about which Black & Veatch is aware (and in some cases expert users of). Black & Veatch separately conferred to discuss the differences and determine if the differences were significant enough to cause model result deviations (from what other models might generate).

Another important attribute of the Risk Model architecture is the manner in which assets relate to each other in a hierarchical way. The asset hierarchy is used in the asset register to aggregate risk up from the asset class level to the substation/circuit levels and to display outputs and results at the substation/circuit levels. Figure 6-2 shows the asset hierarchy for the Risk Model that was provided by BMcD.

The asset hierarchy described within the Risk Model are used to identify the capital expenditures for substations and circuits; not all of IPL's asset classes and assets, however, are evaluated within the Risk Model. Some examples of asset classes *not* included in the Risk Model include: the Central Business District assets, communication system assets, protection devices, relays, and switches.

Figure 6-1 Risk Model Asset Hierarchy



Black & Veatch offers the following observations regarding its inspection of the Risk Model architecture:

- The Risk Model's architecture aligns with risk models that Black & Veatch has developed for other utilities evaluating asset replacements.
- The Risk Model asset hierarchy also aligns with risk models that Black & Veatch is familiar with.
- By *alignment*, Black & Veatch means:
  - The model structure – down to the modules themselves -- is very similar to that which Black & Veatch is familiar, and which it applies in other jurisdictions.
  - The modules interact and relate in ways required to determine the necessary model evaluation outputs, namely: heat maps and summary graphs showing risk reduction, expenditures and

the ratios of these. Black & Veatch found no gaps that would imply the inability to generate the intended computational outputs.

- The asset classes selected for the model are the same as those included in the risk models presented by Black & Veatch in other TDSIC filings. For circuits the risk is aggregated from the section (i.e. pole/tower and conductor) level to a circuit level in order to understand the impact circuits have on the system. However, the Risk Model pinpoints risk of specific sections to prioritize replacement within the circuits.

In brief, Black & Veatch found no weaknesses or gaps in the Risk Model from an architecture design standpoint. It is built in a way that an asset manager proficient in ISO 55000 and ISO 31000 practice norms would find logical, reasonable, sufficient, and required.

7.0 Inspection and Review of the Risk Model Formulas

Black & Veatch used the Risk Model architecture as a guide to review the Risk Model formulas. Due to the proprietary nature of the Risk Model, Black & Veatch's formula inspection was performed as BMcD demonstrated and discussed the model with Black & Veatch, explaining the major parts of the Risk Model. This occurred as part of several in person and web-based meetings.

Similar to the architecture review, Black & Veatch inquired about formulas in an organized and systematical way to learn more about the formulas and trace how they were operating within the model. Black & Veatch used these occasions to inquire deeply about how the model formulae were constructed, and why certain methods were applied. As with the architecture review, Black & Veatch levered its own expertise in developing and operating similar models. When there were differences in approaches, the BMcD and Black & Veatch participants talked freely about what was behind these choices in approach. Throughout, Black & Veatch was mindful about inquiring about formulas and deliberately focused on the ones that had the greatest influence on model results.

Black & Veatch offers the following observations regarding its inspection of the Risk Model formulas:

- The Risk Model formulas align with other risk models that Black & Veatch has developed for other Indiana TDSIC filings and other places.
- By alignment in this context, Black & Veatch means:
  - The formulas appear logical and well structured,
  - They appear to perform the necessary computations correctly,
  - The layout allows for copying and pasting formulas to prevent formula errors,
  - Formulas are linked to key settings so that when the settings are updated the changes flows to all applicable formulas.

8.0 Inspection and Review of the Risk Model Data Sets (Inputs)

As part of IPL's ongoing asset management efforts, IPL was able to assemble a large quantity of data for potential use within the Risk Model. First, IPL focused on data that it knew would be structured and evaluated within the Risk Model. (As noted earlier, some asset classes were excluded). Next, IPL provided data that resides in its Geographic Information System ("GIS"), Osmose, and Excel spreadsheets. Black & Veatch reviewed the asset data provided to BMcD to gain a familiarity with it. As part of in person and web-based sessions BMcD explained to Black & Veatch how the data was set up with the model and how the various modules and formulas operated in it. During these sessions Black & Veatch asked many questions to gain an understanding about the way BMcD applied the data in the Risk Model.

In addition to the review, Black & Veatch used some of the IPL data (specific to the Risk Model) to do a spot check.

The principal or main types of data provided to BMcD were as follows:

- Asset Record Information
  - Unique Identifiers used for asset identification
  - Asset Description
  - Install Year
  - Location
  - Other key information needed for the asset register
- Depreciation Studies
- Asset Health Information (e.g. condition assessment scores and framework and IPL Asset Management documentation)
- IPL's Existing Consequence Framework
- IPL's Asset Hierarchy
- Geodatabase Query

Black & Veatch offers the following observations regarding its inspection of the Risk Model Data Sets:

- IPL has more asset health information and scoring guidelines available than other utilities for which Black & Veatch has developed risk models. This information provides a better understanding of the actual health of the assets to determine the effective age instead of only relying on chronological age. The overall impact of the data was to decrease the average age of those assets and provide more validation that the model likelihood of failure was not overstated.
- The install year was not available for every asset in each asset class so BMcD used age infilling to determine the install year. The methods used for infilling age were appropriate to use when developing risk models.

9.0 Inspection and Review of the Risk Model Input Assumptions

Black & Veatch distinguishes here between the *data sets* (above) and other forms of input *assumptions*. The data sets are of course inputs. In this section, however, Black & Veatch focuses on model assumptions that operate on many of the data sets.

In a way comparable to the review of the architecture, Black & Veatch completed a sample-oriented inspection and review of the Risk Model input assumptions as part of in person and web-based meetings. BMcD, as before, broadcasted the Risk Model. Black & Veatch used these sessions to inquire about the input assumptions as they were encountered. Later, Black & Veatch met as a team to discuss the input assumptions, differences from Black & Veatch's experience in applying similar factors to its asset risk models. The focus of course was on assumptions of significant importance to the Risk Model results.

The main assumptions that Black & Veatch reviewed are as follows:

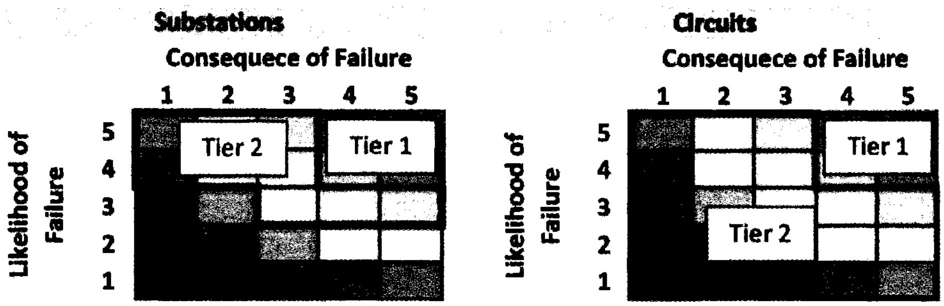
- Unit Cost Data
- Inflation Factor
- Asset Depreciation Curves
- Average Service Lives
- Criticality Criteria
- Red Zone Selection
- IPL Resource Constraints

Black & Veatch offers the following observations regarding its inspection of the Risk Model Input Assumptions:

- Unit Cost Data – Black & Veatch reviewed the unit cost data that IPL provided to BMcD for the Risk Model and Black & Veatch was comfortable with the Association for the Advancement of Cost Engineering ("AACE") class estimates.
- Use of Asset Depreciation Curves – Black & Veatch compared BMcD's selection of each asset class depreciation curve with other utilities. Though differences are observed, the selection methods and curve usage aligned with the other utilities. By alignment in this context, Black & Veatch means the shape of the curves were the same or similar.
- Average Service Lives – Overall IPL has longer average service lives than the other utilities that Black & Veatch compared. This appears to be the result of the efforts IPL has undertaken around asset management. This means that when the model identifies assets for replacement, they are already older than other utilities.
- Criticality Criteria – BMcD's method uses a wide range of scores to weight the impact of consequence of failure while some other models used and reviewed by Black & Veatch applied a multiplier to weight the score. Though the methods are slightly different, both work well to state the consequence of failure for each asset class to understand the overall system risk. In addition to reviewing the criteria, Black & Veatch worked with BMcD and IPL to calibrate the consequence of failure definitions and related score. The resulting consequence of failure details can be found in the BMcD Risk Model Report. To further explain, BMcD chose to score consequence of failure with a graduated scale with up to 16 different consequence levels that ranged from a score of 0 to 1,000. The appropriate score was developed and applied to the different asset classes. There were six different failure (i.e., consequence) categories (e.g. Safety Impact, Customer Impact, Environmental Impact, Restoration, System Operation/Production, and Regulatory/Public). The categories have multiple criteria within them and the Risk Model uses the max score within each.
- Red Zone Selection – The Red Zone is used as a guide when developing the TDSIC plan for substations and circuits. In this Risk Model, the Red Zone represents tier one assets. This includes

assets that have a consequence of failure ("COF") of greater than, or equal to 4 and an LOF of greater than, or equal to 4. Assets in this region were targeted for replacement first within the seven-year period. The Red Zone approach used in the Risk Model covers less of the risk grid than other risk models Black & Veatch has worked with; however, it still is appropriate for the Risk Model as it uses the tier one assets to identify highest risk assets for replacement and then relies on tier two to focus investment based on risk reduction per dollar spent.

Figure 9-1 Red Zone Target Region – IPL



- IPL Resource Constraints – BMcD designed the Risk Model to handle resource constraints and then worked with IPL to calibrate the limits for each asset class. An example of this is restricting the Risk Model with the number of circuits that are able to be replaced in a given year based on resources and system availability. This approach aligns with the way Black & Veatch constrained the risk models it presented in other Indiana cases. By alignment in this context, Black & Veatch means that the other models had the ability to also limit the number of assets class replacements per year.

10.0 Inspection and Review of the Model's General Rules

The Risk Model has a wide range of broad or general rules used to apply the various input assumptions to each asset in the Risk Model. This allows for the user to adjust information to the thousands of asset records and allows for the model to be updated annually.

As with the review of the architecture (in person, etc.) Black & Veatch reviewed the Risk Model general rules with BMcD. Similar to the architecture review, Black & Veatch reviewed general rules and requested additional explanations when unfamiliar rules were found (per Black & Veatch's experience). Black & Veatch met as a team to discuss the differences, determining their importance and impact.

The main types of general rules that Black & Veatch reviewed are as follows:

- Infilling of Missing Install Years
- Effective Age Adjustments
- Consequence of Failure Scoring Rules

Black & Veatch offers the following observations regarding its inspection of the Risk Model Data Sets:

- Infilling of Missing Install Years – The availability of asset's install year is a common issue that utilities are faced with when developing a risk model. IPL was not unique with the data that was available for determining the age of their assets.

There was sufficient substation asset data to determine an install year for breakers and power transformer assets.

- The install year for batteries, breakers, and power transformers were not in the system so an IPL subject matter expert ("SME") reviewed physical records to determine the install year.
- For the circuit assets, there were more data gaps with the install date for the conductor.
- There was good install year asset data for poles and towers so BMcD used the GIS information to match poles and towers with conductors to determine the install year.

- Effective Age Adjustments – The availability of condition test data allows for an asset's effective age to be determined by adjusting the chronological age to incorporate the health of the asset. IPL had good condition data available for breakers, power transformers, and poles. In addition to the data, IPL already had the data in a format that was easy to use along with testing thresholds that allowed BMcD to determine the asset health. These were the only assets in the Risk Model that had asset health data.
- Consequence of Failure Scoring Rules – The scoring rules allow for the Risk Model to assign a consequence of failure score to each of the asset records in the model. BMcD worked directly with IPL SMEs to understand the magnitude of failure for each of the asset classes in the Risk Model and then applied the rules. This is the same approach Black & Veatch has used to develop scoring rules in similar risk models.

11.0 Inspection and Review of Model Results

Black & Veatch discussed the Risk Model results when BMcD was finalizing the circuits and substations that would be included in the TDSIC filing. IPL, BMcD, and Black & Veatch had numerous web meetings where BMcD would show the Risk Model outputs and explain the way the scenario was developed along with the drivers that caused the Risk Model to select the various circuits and substations for replacement. As with the architecture review, Black & Veatch levered its own expertise in developing and operating similar models. When there were differences in the results, the BMcD and Black & Veatch participants talked freely about what was behind these results.

In addition to discussing the Risk Model results with BMcD, Black & Veatch also reviewed the results based on Black & Veatch's experience with similar risk modeling. A portion of the Risk Model was also recreated by Black & Veatch to check the application of likelihood of failure curves to one of the asset classes in the Risk Model.

Black & Veatch offers the following observations regarding its inspection of the Risk Model formulas:

- Risk Model Results Generation – The Risk Model provides results over a seven-year period and the risk reduction results aligns with the range of risk reduction in similar risk modeling conducted by Black & Veatch. By alignment in this context, Black & Veatch means the Risk Model shows a 36.6% reduction in risk as compared to the other modeling that ranges from 21% to 40% risk reduction. After reviewing the architecture, input data and assumptions, and other model attributes described in this memorandum, Black & Veatch found that the model performs the computations effectively.
- Risk Model Simulation – The Risk Model simulation performed by Black & Veatch resulted in the same likelihood of failure score as the one that was shown in the Risk Model that was developed by BMcD.

12.0 Conclusion

Black & Veatch undertook a thorough review of the Risk Model developed by BMcD in the manner described (in person meetings, web-based sessions, and recreation of certain functionality). The fundamental approach of taking IPL's data and developing asset registers that were then used to prioritize capital expenditures to target assets in the Red Zone is the same as that taken in similar Black & Veatch risk modeling. The Risk Model developed by BMcD has differences around the consequence framework, effective age adjustments, and the COF and LOF scoring of circuit segments. However, after reviewing the model, Black & Veatch feels confident that the Risk Model is appropriate to use to identify capital expenditures for substations and circuits that are part of IPL's TDSIC filing.

The Economic Impacts of IPL's Plan to Upgrade its Electric Transmission and Distribution System

July 2019

KELLEY SCHOOL OF BUSINESS
INDIANA UNIVERSITY
Indiana Business Research Center

Appendix 8.5 IBRC's Economic Impact Assessment Report

The Economic Impacts of IPL's Plan to Upgrade its Electric Transmission and Distribution System

July 2019

Prepared for
Indianapolis Power & Light Company

By
Indiana Business Research Center,
Kelley School of Business, Indiana University

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Executive Summary

Indianapolis Power & Light Company (IPL) has developed a Transmission Distribution Storage System Improvement Charge (TDSIC) Plan to invest approximately $1.2 billion over the next seven years to update and modernize the electric transmission and distribution (T&D) system in IPL's Central Indiana service territory. The broad range of activities IPL intends to undertake with this Plan are designed to better serve its customers by improving the reliability, efficiency and safety of IPL's system. While these are the core benefits of IPL's plan to improve and modernize its system, these investments will also provide secondary benefits for the area by generating additional economic activity.

In order to estimate these secondary economic benefits from this Plan, IPL partnered with the Indiana Business Research Center (IBRC) at Indiana University's Kelley School of Business to conduct an analysis of these activities and measure the economic ripple effects that this investment will generate both in Marion County and statewide.

The key findings from this analysis show that IPL's approximately $1.2 billion investment over this seven-year period will support an estimated 880 jobs annually in Marion County worth $62.2 million in compensation (i.e., pay and benefits) per year (see **Table 1**). In terms of the broader economy, IPL's activities will contribute an estimated average of $92.6 million to Marion County's gross domestic product (GDP) annually over the life of the Plan. This increased economic activity will also generate roughly $3.3 million per year in state and local government revenues.

Looking over the full span of the TDSIC Plan, IPL's investments will amount to more than $435 million in compensation in Marion County and nearly $648 million in GDP.

Table 1: Marion County—Average Annual Economic Contributions of IPL Capital Investments, 2020 to 2026

	Direct Effects	Ripple Effects	Total Effects	Multiplier
Employment	580	300	880	1.52
Compensation (millions, 2019 $)	$45.2	$17.0	$62.2	1.38
GDP (millions, 2019 $)	$63.4	$29.2	$92.6	1.46
State and Local Tax Revenue (millions, 2019 $)	—	—	$3.3	—

Source: IBRC, using data from IPL and the IMPLAN economic modeling software

When we broaden our focus to the state level, these average annual economic contributions rise to a total of 950 jobs, $66 million in compensation and nearly $99 million in GDP.

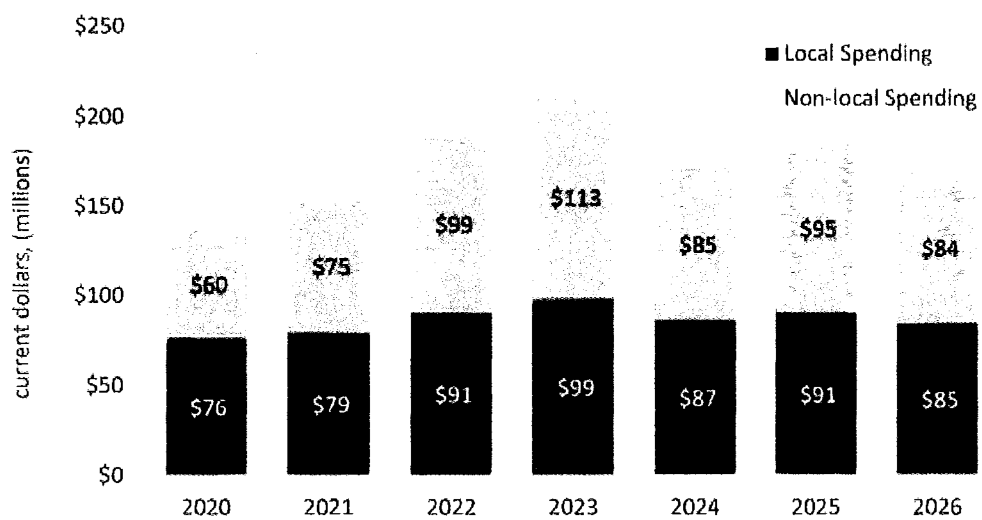
The report that follows will provide more detail on these findings, as well as outline the methodology used to produce these estimates.

Estimates of Economic Contributions

Figure 1 outlines IPL's expected spending over the next seven years to upgrade and modernize its electric T&D system in Central Indiana. IPL plans to invest an average of $174.1 million per year over this period, with peak spending in 2023 when expenditures will reach nearly $212 million. In all, IPL's TDSIC Plan calls for approximately $1.2 billion in capital investment over this span.

As with any production or construction activity, some portion of supply-chain spending will leak outside of the local economy (Marion County in this case) to manufacturers and service providers that are located elsewhere. Given that upgrading and modernizing an electric T&D system requires a good deal of highly specialized equipment and material, IPL estimates that slightly more than half of this spending—or $611.6 million over the seven-year period—will go to vendors outside the local area. Within the framework of economic impact analysis, this "non-local" spending is considered a leakage and does not factor into the economic contributions of IPL's investments discussed in this report.

Figure 1: IPL's Projected Annual Spending for Electric Transmission and Distribution System Upgrades



Source: IPL

In terms of local expenditures, IPL expects to spend an average of $86.7 million per year in Marion County over the life of this Plan. In the terminology of economic impact analysis, these local expenditures and the associated employment describe the "direct effects" of IPL's investments on the local economy. The benefits of these investments do not end there, however. The additional economic activity generated by these direct effects—the supply chain purchases from other businesses in the area along with the household spending of workers engaged in these T&D system improvements—cascade throughout the local economy.

In order to estimate these so-called economic "ripple effects," the IBRC used the IMPLAN economic modeling software to conduct an input-output analysis for IPL's TDSIC Plan. This widely used software relies on a variety of secondary data sources to build economic models that are tailored to reflect the unique industry mix of any given geographic area (the IBRC constructed separate models for Marion County and Indiana for this study). The ripple effect estimates derived from this analysis combine with the direct effects to describe the full economic contributions of IPL's investments.

Economic Effects of IPL's TDSIC Plan

As discussed earlier, IPL expects to spend an average of $174.1 million per year over the next seven years to upgrade and modernize its T&D system. The portion of this total that IPL expects to spend in Marion County will support an estimated 580 direct jobs per year in the area over the life of the project. These jobs will largely be concentrated in the construction and engineering fields. Along with these direct employment effects, this increased economic activity will support an additional 300 local ripple effect jobs per year resulting from supply chain purchases and the household spending associated with these direct jobs (see **Table 2**). This brings the full employment footprint of IPL's TDSIC Plan to an estimated 880 jobs per year between 2020 and 2026. This total employment impact will combine to produce an estimated $62.2 million in total compensation, which translates into nearly $70,700 in annual compensation per worker.

A helpful way to interpret these impacts is to look at the multipliers. The ratio of direct jobs to total jobs, for instance, gives a ratio of 1.52, meaning that every job directly tied to IPL's TDSIC Plan support another 0.52 jobs with other employers in the area (or every 10 direct jobs support slightly more than 5 additional jobs elsewhere). The compensation multiplier of 1.38 suggests that every dollar of direct payroll generates an additional $0.38 in compensation with other local employers.

In terms of total economic activity, the full impact of these IPL activities will combine to contribute an estimated $92.6 million per year to Marion County's gross domestic product (GDP) over the seven-year period. The multiplier of 1.46 indicates that every dollar of GDP directly generated by these investments will trigger an additional $0.46 in economic activity in the area.

IPL's TDSIC Plan to upgrade its T&D system will also generate state and local government revenues. The IMPLAN model estimates the tax revenues from business profits, indirect business taxes (e.g., sales, property and excise taxes), personal taxes (e.g., income and property taxes), and employer and employee contributions to social insurance. Fueled primarily by sales and property taxes, this investment in T&D system modernization will generate an estimated $3.3 million per year in state and local government revenue.

Table 2: Marion County—Average Annual Economic Contributions of IPL Capital Investments, 2020 to 2026

	Direct Effects	Ripple Effects	Total Effects	Multiplier
Employment	580	300	880	1.52
Compensation (millions, 2019 $)	$45.2	$17.0	$62.2	1.38
GDP (millions, 2019 $)	$63.4	$29.2	$92.6	1.46
State and Local Tax Revenue (millions, 2019 $)	—	—	$3.3	—

Source: IBRC, using data from IPL and the IMPLAN economic modeling software

As the supply chains that support IPL's investment activities extend to other parts of Indiana, the additional spending supports another 70 ripple effect jobs and the total employment impact of the TDSIC Plan expands from 880 jobs in Marion County to 950 jobs statewide (see **Table 3**). Furthermore, the average annual GDP impact of these investments will reach nearly $99 million at the state level.

Table 3: Indiana—Average Annual Economic Contributions of IPL Capital Investments, 2020 to 2026

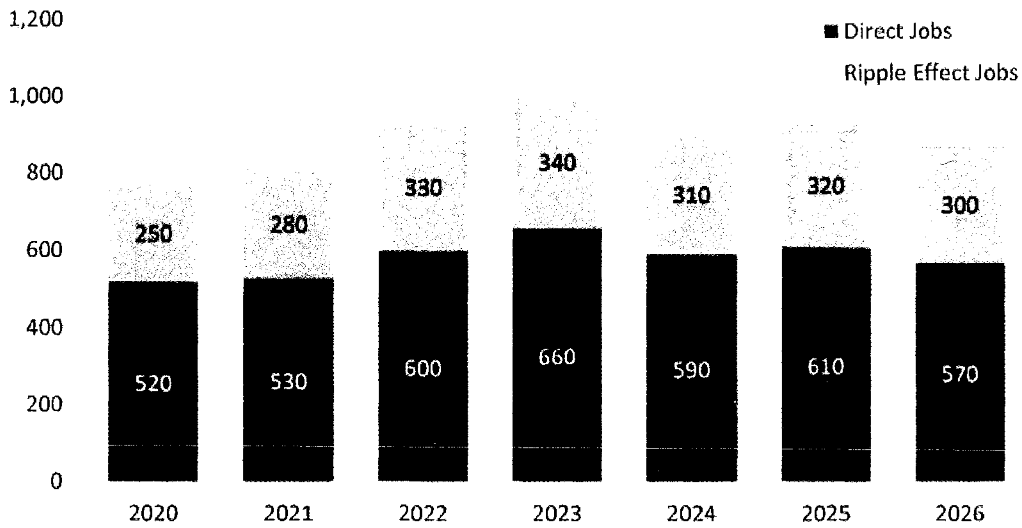
	Direct Effects	Ripple Effects	Total Effects	Multiplier
Employment	580	370	950	1.64
Compensation (millions, 2019 $)	$45.2	$20.7	$65.9	1.46
GDP (millions, 2019 $)	$63.4	$35.1	$98.5	1.55
State and Local Tax Revenue (millions, 2019 $)	—	—	$3.5	—

Source: IBRC, using data from IPL and the IMPLAN economic modeling software

Economic Impacts by Year

IPL's investments will ramp up from nearly $137 million in 2020 to a peak of roughly $212 million in 2023 before then subsiding a bit over the last three years of the Plan. The annual employment effects of this spending will follow a similar trajectory, with Marion County job totals reaching 1,000 by 2023 (see **Figure 2**). Over the seven-year period, the employment impacts of IPL's TDSIC Plan will never fall below an estimated 770 jobs in the county.

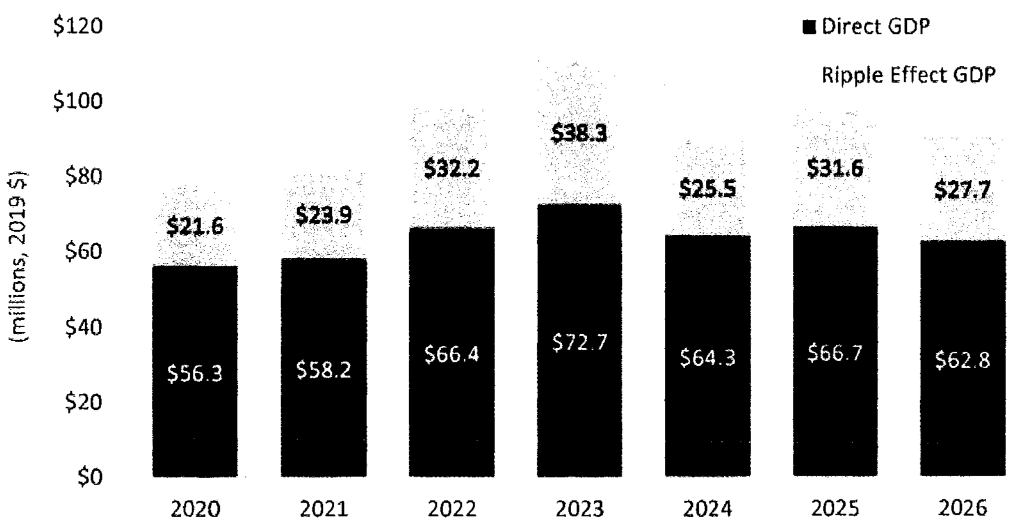
Figure 2: Marion County—Annual Employment Effects of IPL Capital Investments



Source: IBRC, using data from IPL and the IMPLAN economic modeling software

Annual contributions to Marion County's GDP will also top out in 2023, with total value added of approximately $111 million expected in that year (see **Figure 3**). In all other years, the GDP effects will range between nearly $80 million to roughly $99 million.

Figure 3: Marion County—Annual GDP Effects of IPL Capital Investments



Source: IBRC, using data from IPL and the IMPLAN economic modeling software

Appendix

Key Terms

Direct Effects: Refers to the increase in final demand or employment in a given area that can be attributed specifically to IPL's TDSIC Plan.

Ripple Effects: A combination of the indirect and induced effects generated by the direct effects. Indirect effects measure the change in dollars or employment caused when IPL increases its purchase of goods and services from suppliers and, in turn, those suppliers purchase more inputs and so on throughout the economy. Induced effects reflect the changes—whether in dollars or employment— that result from the household spending of direct workers, along with the employees in the supply chain.

Total Effects: The total of all economic effects is the size of the economic impact and is the sum of the direct and ripple effects. The IMPLAN model also tracks the tax effects associated with all the transactions and economic activity associated with the direct and ripple effects. For example, household spending at retailers generates state sales tax. In addition, those retailers also pay property taxes to local governments. As a result, this analysis was also able to estimate the state and local government tax flows.

Multiplier: The multiplier is the magnitude of the economic response in a particular geographic area associated with a change in the direct effects. The multiplier equals the total effect divided by the direct effect.

GDP: Also known as value added, GDP is a measure of the economic activity generated by a company, industry, state, nation, etc. GDP is the difference between total output (i.e., sales) and the cost of production inputs. GDP consists of four components: employee compensation, proprietor income, other property income and indirect business tax.

About IMPLAN Economic Modeling Software

IMPLAN is built on a mathematical input-output (I-O) model that expresses relationships between sectors of the economy in a chosen geographic location. In expressing the flow of dollars through a regional economy, the input-output model assumes fixed relationships between producers and their suppliers based on demand. It also omits any dollars spent outside of the regional economy—say, by producers who import raw goods from another area, or by employees who commute and do their household spending elsewhere.

The idea behind input-output modeling is that the inter-industry relationships within a region largely determine how that economy will respond to economic changes. In an I-O model, the increase in demand for a certain product or service causes a multiplier effect, layers of effect that come in a chain reaction. Increased demand for a product affects the producer of the product, the producer's employees, the producer's suppliers, the supplier's employees, and so on—ultimately generating a total effect in the economy that is greater than the initial change in demand. For instance, say demand for Andersen Windows' wood window products increases. Sales grow, so Andersen has to hire more people, and the company may buy more from local vendors, and those vendors in turn have to hire more people … who in turn buy more groceries. The ratio of that overall effect to the initial change is called a regional multiplier and can be expressed like this:

(Direct Effect + Indirect Effects + Induced Effects) / (Direct Effect) = Multiplier

Multipliers are industry- and region-specific. Each industry has a unique output multiplier, because each industry has a different pattern of purchases from firms inside and outside of the regional economy. (The output multiplier is in turn used to calculate income and employment multipliers.)

Estimating a multiplier is not the end goal of IMPLAN users. Most wish to estimate other numbers and get answers to questions such as: How many jobs will this new firm produce? How much will the local economy be affected by this plant closing? What will the effects be of an increase in product demand? Based on those user choices, IMPLAN software constructs "social accounts" to measure the flow of dollars from purchasers to producers within the region. The data in those social accounts will set up the precise equations needed to finally answer those questions users have—about the impact of a new company, a plant closing or greater product demand—and yield the answers.

IMPLAN constructs its input-output model using aggregated production, employment and trade data from local, regional and national sources, such as the U.S. Census Bureau's annual *County Business Patterns* report and the U.S. Bureau of Labor Statistics' annual report called *Covered Employment and Wages*. In addition to gathering enormous amounts of data from government sources, the company also estimates some data where they haven't been reported at the level of detail needed (county-level production data, for instance), or where detail is omitted in government reports to protect the confidentiality of individual companies whose data would be easily recognized due to a sparse population of businesses in the area.

The IBRC's analysts have attended advanced training in the use of the IMPLAN modeling software. The estimates that the IBRC analysts generate are scrutinized closely to ensure that they are accurate and reflect the most trustworthy application of the modeling software. In all instances, the most conservative estimation assumptions and procedures are used to produce the IMPLAN results.

Appendix 8.6 Black & Veatch Cost Estimate Review and Validation Report

BLACK & VEATCH COST ESTIMATE REVIEW AND VALIDATION REPORT

BLACK & VEATCH PROJECT NO. 400364

PREPARED FOR

Indianapolis Power & Light Company

JULY 2019

BLACK & VEATCH

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1.1 BLACK & VEATCH CORPORATION

The independent cost review was completed by cost estimating, engineering, and consulting professionals from Black & Veatch Corporation. Founded in 1915, Black & Veatch is a leading global engineering, consulting and construction company. Black & Veatch specializes in these major markets:

- Energy
- Water
- Telecommunications
- Federal
- Management Consulting

Black & Veatch Holding Company is an employee-owned, global company that delivers sustainable infrastructure solutions across the Power, Oil & Gas, Water, Telecommunications and Federal markets. Since 1915, we help clients improve the lives of people in communities worldwide through consulting, engineering, construction, operations and program management services.

1.2 T&D PLAN CAPITAL COST ESTIMATE REVIEW

IPL engaged Black & Veatch to conduct a review of IPL's proposed TDSIC Plan capital cost estimates and estimating process, based on Black & Veatch's knowledge and experience with similar TDSIC project capital cost estimates. The review tested estimates for reasonableness based on Black & Veatch's experience and the information and backup data received from IPL for its cost estimates.

The specific goals of the independent cost review were:

- To validate that the IPL cost estimating process is in accordance with AACE guidelines and
- To identify any recommendations for improvement.

Black & Veatch's review included IPL's cost estimating process for all projects and an independent estimate verification for a representative sample set of Class 2 project cost estimates from IPL's TDSIC plan as described in the following sub-sections. As part of the review, Black & Veatch supported IPL with the development of a uniform method and template for cost estimating to meet AACE Class 2, 3 and 4 guidelines for all project cost estimates. Class 3 and 4 estimate templates completed by IPL subject matter experts were reviewed by a Black & Veatch AACE certified estimator for reasonableness. Black & Veatch developed independent project estimates for a 5% sample of Class 2 project estimates to verify reasonableness of estimation and completeness of project details.

1.3 COST ESTIMATE REVIEW APPROACH

To conduct this review, IPL provided Black & Veatch detailed material and labor estimates developed by the designated IPL engineering subject matter experts and any required external engineering support. Each estimate provided line item details of costs that included quantities, materials, labor costs and any required assumptions. After reviewing the received estimate workbooks and documents, several cost estimating review discussions were conducted to confirm agreement on cost estimate classification criteria and to review IPL cost estimating methodology. Black & Veatch supported IPL with development of cost estimate templates for consistency across all project categories.

Black & Veatch reviewed the Class 3 and Class 4 estimates for the following projects:

1.) Circuit Rebuilds
2.) Substation Asset Replacement
3.) XLPE Cable Replacement
4.) 4 kV Conversion
5.) Tap Reliability Improvement Projects (TRIP)
6.) Meter Replacement
7.) Central Business District (CBD) Secondary Network Upgrades
8.) Static Wire Performance Improvement
9.) Remote Ends – Breaker Relays/ Upgrades
10.) Pole Replacements
11.) Steel Tower Life Extension
12.) Distribution Automation - Reclosers
13.) Deliverability – Substation Upgrades

Black & Veatch developed independent estimates for 5% of the Class 2 estimates that IPL had separately developed. The following projects were chosen to determine if IPL estimates were reasonable and complete for TDSIC purposes of "best estimate".

1. 4 kV Conversion – Stuart 4kv Conversion
2. CBD – Pierson St Phase #1
3. Circuit Rebuilds – Crestview #3
4. Circuit Rebuilds – Northwest #9
5. Substation – Edison Substation
6. Substation – Gardner Lane Substation
7. T-Line Static Replacement – 132-84 Mooresville to Camby
8. TRIP – Lafayette 5 Tap 192-141

1.3.1 IPL's Cost Estimating Approach

IPL developed project cost estimates for each project included in the proposed 7-year TDSIC investment plan; IPL estimated project costs using detailed estimation workbooks and systems supported by subject matter experts. These templates and systems allowed IPL cost estimators to develop estimates using a consistent set of base cost assumptions such as labor rates, material costs, and a variety of other assumptions to drive consistency with respect to its estimates.

Based on discussions with IPL's team, the cost estimates reviewed do not include an adjustment for salvage value of retired equipment/assets in the estimates. As such, Black & Veatch has not reviewed or assessed any estimates of salvage value. The cost estimates reviewed by Black & Veatch do include IPL overhead costs and contingency.

Class 2 estimates were developed for 9 of the 13 Projects for Year 1 and Year 2 of the plan. For the 4 remaining Projects, Class 3 estimates were developed. For the remaining years of the plan (Years 3-7) Class 4 estimates were used, except for the Advanced Distribution Management System (ADMS) Project. A Class 2 estimate was developed for the ADMS Project and the costs were distributed over the 3-year project deployment window.

Table 1 below, lists the three AACE estimate classes that are applicable to the IPL projects in the 7-year TDSIC plan.

Table 1 - AACE Estimate Classification Class 2-4

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed	L: -5% to -15% H: +5% to +20%

These project cost estimates are adjusted from Class 4 to Class 2 as part of IPL's annual TDSIC Plan update process, and when projects are between one and two years from being implemented, detailed project scopes are defined, and cost estimates are developed using the detailed estimation templates and systems.

1.3.2 B&V Approach for Review of T&D Project Cost Estimates

Black & Veatch's approach to complete the IPL Project cost estimate review included independent review of the cost estimating process, procedures and templates for all projects by a certified AACE estimator to confirm consistency with AACE guidelines. Black & Veatch also developed independent cost estimates for a 5% sample set of Class 2 estimates that IPL developed. Black & Veatch's certified AACE estimator, capital cost estimating tools and historical databases were used to develop Black & Veatch's independent estimate.

The independent review of the cost estimating process and templates were completed for all Class 2, Class 3 and Class 4 project estimates and included several review meetings with the IPL subject matter experts and supporting engineering firms to review the templates, and methodology utilized in the estimating process. Black & Veatch provided a detailed review of the AACE guidelines and industry good practice. Recommendations for improvement were provided throughout the review process to support IPL development of project cost estimates. To develop the independent Class 2 project estimates Black & Veatch relied on a templated approach previously applied to check other TDSIC cost estimates. This approach uses a combination of historical labor and material costs from past similar projects, as well as our compilation of material and labor costs for recent electric T&D projects across North America. We then compared the Black & Veatch developed estimates to the IPL estimates and calculated the percent difference in the estimates. Review of any differences were completed with the IPL subject matter experts in each discipline. Finally, Black & Veatch experience and professional judgment were used in completing this check for reasonableness and estimate documentation completeness. Appendix 8.8 of IPL's TDSIC Plan is an example of Class 2 Estimate Worksheet developed by collaboration between Black & Veatch and IPL to support IPL with consistent AACE Estimate Classifications System.

For the projects of a higher AACE Class level, including Class 3 and Class 4, the same level of detailed cost estimates is not available. This is appropriate in that these estimates are used for long term capital planning purposes at a stage where detailed project scope and estimates are not yet feasible. These estimates should include materials and labor assumptions details based on a typical installation. The typical installation included engineering resources, craft labor, and material unit costs. As projects develop from an initial planning stage, towards conceptual design and then to detailed design and procurement before being executed, different levels of detail with respect to the cost estimates are reasonable and consistent with AACE definitions. Appendix 8.10 of IPL's TDSIC Plan is an example of Class 4 Estimate Worksheet developed by collaboration between Black & Veatch and IPL to support IPL with consistent AACE Estimate Classifications System.

For all Class 2, Class 3 and Class 4 cost estimate reviews Black & Veatch used a combination of its professional judgment and experience with similar projects and assets, and review of the IPL estimating process using historical databases and cost estimating tools, and its understanding of the scope of the projects to determine if estimates were reasonable.

The Black & Veatch team performing this review included a team of:

- Senior power delivery cost estimators with 20+ years of experience and expertise in cost estimating for electric transmission and distribution projects.
- AACE certified cost estimator with 15+ years of industry estimating experience.
- Senior power industry project manager with 20+ years of experience planning and managing substantial projects.

1.4 COST ESTIMATE REVIEW RESULTS

Black & Veatch's initial review shows that the IPL cost estimates and cost estimating process are reasonable and consistent with AACE guideline classification. Based on Black & Veatch's review of the process and documentation developed to support each of the project estimates, IPL has utilized the correct AACE Class level to characterize what level of detail the cost estimates are developed to. The level of detail IPL uses to estimate T&D project cost estimates in its long-term T&D investment plan is consistent with good estimating practice within the industry. Additionally, Black & Veatch noted for several project categories, the IPL estimating process for projects in plan years 3-7 utilize a detailed unit cost basis to ensure best estimate of Class 4 project cost.

Table 2 below provides a summary of the AACE Class estimate used by year in the IPL TDSIC Plan.

Table 2 - AACE Class Estimate Used by Year

AACE CLASSIFICATION REVIEW BY PLAN YEAR			
Project Category	**Year 1 & 2**	**Year 3 – 7**	**Estimate Template Check Completed**
1. *Circuit Rebuilds*	*Class 2*	*Class 4*	*YES*
2. *Substation Assets*	*Class 2*	*Class 4*	*YES*
3. *XLPE Cable Replacement*	*Class 3*	*Class 4*	*YES*
4. *4 kV Conversion*	*Class 2*	*Class 4*	*YES*
5. *Tap Reliability Improvement Program*	*Class 2/ Class 4*	*Class 4*	*YES*
6. *Meter Replacement*	*Class 2*	*Class 4*	*YES*
7. *CBD Secondary Network*	*Class 2*	*Class 4*	*YES*
8. *Static Wire Performance Improvement*	*Class 2*	*Class 4*	*YES*
9. *Remote End - Breaker Relay/Upgrades*	*Class 2*	*Class 4*	*YES*
10. *Pole Replacements*	*Class 3*	*Class 4*	*YES*
11. *Steel Tower Life Extension*	*Class 3*	*Class 4*	*YES*
12. *Distribution Automation - Reclosers*	*Class 3*	*Class 4*	*YES*
13. *Deliverability – Substation Upgrades*	Class 2	Class 4	YES

When evaluating the Class 2 estimates in comparison to the Black & Veatch independent estimate many factors can cause significant changes in material and labor costs from month to month and year to year. In today's global economy, market forces impact major equipment suppliers and their costs frequently. These market impacts to costs are then passed on to equipment customers with resulting routine changes to material price quotes. Similarly, contract labor costs can fluctuate significantly in the energy industry based on demand. From a labor cost standpoint, many situations can change the level of effort required to complete a project. Unforeseen site conditions can increase the project duration significantly for one project, when at the same time on a similar project elsewhere the conditions are ideal, and the project duration can be less. This results in a variety of labor costs depending on a variety of factors.

It is in this context that Black & Veatch performed its review. No two cost estimators will arrive at the same cost estimate, even when given the same general scope description of a project. Differences can result from a variety of factors, including the following:

- When the cost estimate was developed – as discussed, market forces impact material prices every day and contract labor costs can fluctuate as demand for experienced labor changes.
- Understanding of site conditions and assumptions. Not all site conditions can be defined fully when estimating a project cost.

These uncertain factors with respect to cost estimates are important to keep in context, and it is with an understanding of this context that Black & Veatch performed its reasonableness review. For the review, IPL provided Black & Veatch "issue for construction" level project packages providing detailed design drawings, line item quantities and site-specific assumptions required to support development of an independent estimate. Additionally, where applicable, contract costs for material and labor estimates for specific planned projects were provided. Black & Veatch independently developed detailed cost estimates, using Black & Veatch estimating tools and historical labor and material costs and the same detailed breakdown used by IPL to compare with the Class 2 estimates provided for review. After the line item estimates were developed, Black & Veatch compared the total estimate to IPL's estimates to calculate a percent difference and assess the reasonableness of the estimate.

The Table 3 below is a summary of Black & Veatch's independent review effort of IPL's Class 2 estimates by project.

Table 3 - Summary of Black & Veatch's Independent Review of IPL Class 2 Estimates

CATEGORY	PROJECT DESCRIPTION	ESTIMATE COMPARISON % (BV TO IPL ESTIMATES)	REASONABLENESS REVIEW COMPLETED	AACE CLASS LEVEL	B&V REVIEWED ESTIMATE DOCUMENTATION
4kv Conversion	Stuart 4kv Conversion	Within +/- 5%	☒	2	☒
CBD	Pierson St Phase #1	Within +/- 5%	☒	2	☒
Circuit Rebuilds	Crestview #3	Within +/- 10%	☒	2	☒
Circuit Rebuilds	Northwest #9	Within +/- 15%	☒	2	☒
Substation	Edison Substation	Within +/- 15%	☒	2	☒
Substation	Gardner Lane Substation	Within +/- 10%	☒	2	☒
T-Line Static Wire Replacement	132-84 Mooresville to Camby	Within +/- 10%	☒	2	☒
TRIP	Lafayette 5 Tap 192-141	Within +/- 5%	☒	2	☒

Table 4 below shows the actual independent estimate results for each of the Class 2 projects in the sample set.

Table 4 - Summary of Black & Veatch and IPL Class 2 Estimate Comparison for 5% Sample Set

CATEGORY	PROJECT DESCRIPTION	BLACK & VEATCH	IPL	% DIFFERENCE
4kV Conversion	Stuart Conversion	$ 3,159,632	$ 3,234,494	+2.4%
CBD	Pierson St. #1	$ 1,062,441	$ 1,026,967	-3.3%
Circuit Rebuilds	Crestview #3	$ 2,437,759	$ 2,200,000	-9.8%
Circuit Rebuilds	Northwest #9	$ 2,534,184	$ 2,202,593	-13.1%
Substation	Edison Substation	$ 3,248,160	$ 3,719,828	+14.5%
Substation	Gardner Lane Substation	$ 1,289,338	$ 1,414,020	+9.7%

T-Line Static Wire Replacement	Mooresville - Camby	$	1,691,672	$	1,805,664	+6.7%
TRIP	Lafayette 5 Tap 192-141	$	815,337	$	859,608	+5.4%

As shown by Table 4, independent cost estimate verification for the 5% sample set of projects validated estimates for Class 2 projects are within +/- 15% which are consistent with the range of accuracy defined in the AACE guidelines shown in Table 1. All project packages reviewed had adequate documentation to meet good practice standards for the defined Class of estimate.

1.5 CONCLUSIONS

Black & Veatch's review of the process, templates and systems used to develop the IPL TDSIC Plan project cost estimates concludes that the project cost estimates reviewed are reasonable and within the typical band of uncertainty seen across the industry for capital planning and cost forecasting. Further, Black & Veatch concludes that the AACE Class levels reported by IPL are valid. Independent cost estimate verification of a 5% sample set of projects validated estimates for Class 2 projects are within +/- 15% providing a high confidence level these projects meet the expected accuracy range defined in the AACE guidelines. All project packages reviewed had adequate documentation to meet good estimating practice standards for the defined Class of estimate. Additionally, Black & Veatch concluded IPL has developed good estimating practice for labor cost estimates to reduce uncertainty through contracts and detailed unit cost reviews for Class 2, Class 3 and Class 4 level estimates.

Public Appendix 8.7 Cost Estimates, Year by Year Project Detail (Sortable List) and Plan Projects by FERC Account

Indianapolis Power & Light Company
7-Year TDSIC Plan by Project

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Project Type	2020	2021	2022	2023	2024	2025	2026	7-Year Total
	Age & Condition Projects								
1	Circuit Rebuilds	$ 27,175,955	$ 25,345,895	$ 45,810,667	$ 52,812,143	$ 47,773,667	$ 49,882,752	$ 49,913,886	$ 298,714,965
2	Substation Assets Replacement	$ 16,731,642	$ 27,023,779	$ 39,896,631	$ 39,220,541	$ 34,451,705	$ 44,283,282	$ 46,536,273	$ 248,143,853
3	XLPE Cable Replacement	$ 12,185,638	$ 11,768,208	$ 12,501,788	$ 12,354,210	$ 12,297,234	$ 12,829,535	$ 12,301,534	$ 86,238,147
4	4 kV Conversion	$ 19,709,314	$ 13,824,988	$ 15,422,783	$ 15,541,783	$ 7,583,329	$ 12,385,359	$ 7,520,673	$ 91,988,229
5	Tap Reliability Improvement Projects	$ 10,896,034	$ 10,404,000	$ 10,612,080	$ 10,824,322	$ 11,040,808	$ 11,261,624	$ 11,486,857	$ 76,525,725
6	Meter Replacement	$ 10,735,674	$ 10,950,388	$ 11,169,395	$ 11,392,783	$ 11,620,639	$ -	$ -	$ 55,868,879
7	CBD Secondary Network Upgrades	$ 4,585,019	$ 5,918,264	$ 5,311,051	$ 5,888,219	$ 5,001,613	$ 5,892,283	$ 6,373,447	$ 38,969,896
8	Static Wire Performance Improvement	$ 4,765,917	$ 6,881,909	$ 9,502,181	$ 11,200,958	$ 11,497,320	$ 10,679,473	$ 7,601,921	$ 62,129,679
9	Remote End - Breaker Relay/Upgrades	$ 3,042,255	$ 2,017,899	$ 5,578,433	$ 1,608,007	$ 6,234,867	$ 3,110,142	$ 6,425,834	$ 28,017,437
10	Pole Replacements	$ 3,256,134	$ 3,321,256	$ 3,387,682	$ 3,455,435	$ 3,524,544	$ 3,595,035	$ 3,666,935	$ 24,207,021
11	Steel Tower Life Extension	$ 1,138,320	$ 1,111,147	$ 1,082,432	$ 850,792	$ -	$ -	$ -	$ 4,182,691
12	**Age & Condition Projects Total**	$ 114,221,902	$ 118,567,733	$ 160,275,123	$ 165,149,193	$ 151,025,726	$ 153,919,485	$ 151,827,360	$ 1,014,986,522
	Deliverability Projects								
13	Distribution Automation	$ 18,815,340	$ 19,191,646	$ 13,644,103	$ 13,916,985	$ 14,195,325	$ 14,479,231	$ 14,768,816	$ 109,011,446
14	Substation Design Upgrades	$ 3,795,549	$ 16,213,025	$ 15,809,877	$ 32,905,072	$ 6,323,236	$ 16,777,568	$ 2,632,615	$ 94,456,942
15	**Deliverability Projects Total**	$ 22,610,889	$ 35,404,671	$ 29,453,980	$ 46,822,057	$ 20,518,561	$ 31,256,799	$ 17,401,431	$ 203,468,388
16	**Total Capital Costs**	$ 136,832,791	$ 153,972,404	$ 189,729,103	$ 211,971,250	$ 171,544,287	$ 185,176,284	$ 169,228,791	$ 1,218,454,910
17	Amount of Transmission	$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176	$ 30,641,731	$ 213,710,716
18	Amount of Distribution	$ 114,385,862	$ 126,396,966	$ 156,047,612	$ 175,545,958	$ 137,899,628	$ 155,881,108	$ 138,587,060	$ 1,004,744,194
19	**Total Capital Costs**	$ 136,832,791	$ 153,972,404	$ 189,729,103	$ 211,971,250	$ 171,544,287	$ 185,176,284	$ 169,228,791	$ 1,218,454,910

Indianapolis Power & Light Company
7-Year TDSIC Plan by FERC Account

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Project Type	2020	2021	2022	2023	2024	2025	2026	7-Year Total
	Transmission								
1	352 - Structures and Improvements	$ -	$ -	$ -	$ 2,300,385	$ 2,844,940	$ -	$ 2,632,615	$ 7,777,940
2	353 - Station Equipment	$ 16,542,692	$ 19,582,382	$ 23,096,878	$ 22,073,157	$ 19,302,399	$ 18,615,703	$ 20,407,195	$ 139,620,406
3	354 - Towers and Fixtures	$ 1,138,320	$ 1,111,147	$ 1,082,432	$ 850,792	$ -	$ -	$ -	$ 4,182,691
4	356 - Overhead Conductors and Devices	$ 4,765,917	$ 6,881,909	$ 9,502,181	$ 11,200,958	$ 11,497,320	$ 10,679,473	$ 7,601,921	$ 62,129,679
5	**Transmission Total**	$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176	$ 30,641,731	$ 213,710,716
	Distribution								
6	362 - Station Equipment	$ 7,026,754	$ 25,672,321	$ 38,188,063	$ 49,360,078	$ 24,862,469	$ 45,555,289	$ 32,554,913	$ 223,219,887
7	364 - Poles, Towers, and Fixtures	$ 39,069,911	$ 34,048,557	$ 47,918,689	$ 52,531,374	$ 44,678,960	$ 49,169,935	$ 46,385,522	$ 313,802,948
8	365 - Overhead Condustors and Devices	$ 28,815,380	$ 27,771,432	$ 26,078,201	$ 27,620,140	$ 25,686,598	$ 27,204,806	$ 26,696,855	$ 189,873,412
9	366 - Underground Conduit	$ 2,250,626	$ 2,346,110	$ 2,405,220	$ 2,690,012	$ 1,809,774	$ 2,715,591	$ 2,769,903	$ 16,987,236
10	367 - Underground Condustors and Devices	$ 13,966,103	$ 13,407,560	$ 14,443,018	$ 14,226,294	$ 14,093,313	$ 14,938,612	$ 14,497,783	$ 99,572,683
11	368 - Line Transformers	$ 12,521,414	$ 12,200,598	$ 15,845,026	$ 17,725,277	$ 15,147,875	$ 16,296,875	$ 15,682,084	$ 105,419,149
13	370.01 - Meters - Smart Meters	$ 10,735,674	$ 10,950,388	$ 11,169,395	$ 11,392,783	$ 11,620,639	$ -	$ -	$ 55,868,879
14	**Deliverability Total**	$ 114,385,862	$ 126,396,966	$ 156,047,612	$ 175,545,958	$ 137,899,628	$ 155,881,108	$ 138,587,060	$ 1,004,744,194
15	**Total Capital Costs**	$ 136,832,791	$ 153,972,404	$ 189,729,103	$ 211,971,250	$ 171,544,287	$ 185,176,284	$ 169,228,791	$ 1,218,454,910

Indianapolis Power & Light Company
7-Year TDSIC Plan by Project - Transmission

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Project Type	2020	2021	2022	2023	2024	2025	2026	7-Year Total
	Age & Condition Projects								
1	Circuit Rebuilds	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Substation Assets Replacement	$ 9,704,888	$ 18,155,088	$ 17,779,934	$ 6,785,036	$ 11,168,933	$ 16,408,152	$ 15,296,241	$ 95,298,272
3	XLPE Cable Replacement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	4 kV Conversion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Tap Reliability Improvement Projects	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Meter Replacement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	CBD Secondary Network Upgrades	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Static Wire Performance Improvement	$ 4,765,917	$ 6,881,909	$ 9,502,181	$ 11,200,958	$ 11,497,320	$ 10,679,473	$ 7,601,921	$ 62,129,679
9	Remote End - Breaker Relay/Upgrades	$ 3,042,255	$ 1,427,294	$ 5,316,944	$ 809,508	$ 4,655,170	$ 2,207,551	$ 5,110,954	$ 22,569,676
10	Pole Replacements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Steel Tower Life Extension	$ 1,138,320	$ 1,111,147	$ 1,082,432	$ 850,792	$ -	$ -	$ -	$ 4,182,691
12	Age & Condition Projects Total	$ 18,651,380	$ 27,575,438	$ 33,681,491	$ 19,646,294	$ 27,321,423	$ 29,295,176	$ 28,009,116	$ 184,180,318
	Deliverability Projects								
13	Distribution Automation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Substation Design Upgrades	$ 3,795,549	$ -	$ -	$ 16,778,998	$ 6,323,236	$ -	$ 2,632,615	$ 29,530,398
15	Deliverability Projects Total	$ 3,795,549	$ -	$ -	$ 16,778,998	$ 6,323,236	$ -	$ 2,632,615	$ 29,530,398
16	Total Capital Costs	$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176	$ 30,641,731	$ 213,710,716
17	Amount of Transmission	$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176	$ 30,641,731	$ 213,710,716
18	Amount of Distribution	$ 114,385,862	$ 126,396,966	$ 156,047,612	$ 175,545,958	$ 137,899,628	$ 155,881,108	$ 138,587,060	$ 1,004,744,194
19	Total Capital Costs	$ 136,832,791	$ 153,972,404	$ 189,729,103	$ 211,971,250	$ 171,544,287	$ 185,176,284	$ 169,228,791	$ 1,218,454,910

Indianapolis Power & Light Company
7-Year TDSIC Plan by Project - Distribution

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Project Type	2020	2021	2022	2023	2024	2025	2026	7-Year Total
	Age & Condition Projects								
1	Circuit Rebuilds	$ 27,175,955	$ 25,345,895	$ 45,810,667	$ 52,812,143	$ 47,773,667	$ 49,882,752	$ 49,913,886	$ 298,714,965
2	Substation Assets Replacement	$ 7,026,754	$ 8,868,691	$ 22,116,697	$ 32,435,505	$ 23,282,772	$ 27,875,130	$ 31,240,032	$ 152,845,581
3	XLPE Cable Replacement	$ 12,185,638	$ 11,768,208	$ 12,501,788	$ 12,354,210	$ 12,297,234	$ 12,829,535	$ 12,301,534	$ 86,238,147
4	4 kV Conversion	$ 19,709,314	$ 13,824,988	$ 15,422,783	$ 15,541,783	$ 7,583,329	$ 12,385,359	$ 7,520,673	$ 91,988,229
5	Tap Reliability Improvement Projects	$ 10,896,034	$ 10,404,000	$ 10,612,080	$ 10,824,322	$ 11,040,808	$ 11,261,624	$ 11,486,857	$ 76,525,725
6	Meter Replacement	$ 10,735,674	$ 10,950,388	$ 11,169,395	$ 11,392,783	$ 11,620,639	$ -	$ -	$ 55,868,879
7	CBD Secondary Network Upgrades	$ 4,585,019	$ 5,918,264	$ 5,311,051	$ 5,888,219	$ 5,001,613	$ 5,892,283	$ 6,373,447	$ 38,969,896
8	Static Wire Performance Improvement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Remote End - Breaker Relay/Upgrades	$ -	$ 590,605	$ 261,489	$ 798,499	$ 1,579,697	$ 902,591	$ 1,314,880	$ 5,447,761
10	Pole Replacements	$ 3,256,134	$ 3,321,256	$ 3,387,682	$ 3,455,435	$ 3,524,544	$ 3,595,035	$ 3,666,935	$ 24,207,021
11	Steel Tower Life Extension	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	**Age & Condition Projects Total**	$ 95,570,522	$ 90,992,295	$ 126,593,632	$ 145,502,899	$ 123,704,303	$ 124,624,309	$ 123,818,244	$ 830,806,204
	Deliverability Projects								
13	Distribution Automation	$ 18,815,340	$ 19,191,646	$ 13,644,103	$ 13,916,985	$ 14,195,325	$ 14,479,231	$ 14,768,816	$ 109,011,446
14	Substation Design Upgrades	$ -	$ 16,213,025	$ 15,809,877	$ 16,126,074	$ -	$ 16,777,568	$ -	$ 64,926,544
15	**Deliverability Projects Total**	$ 18,815,340	$ 35,404,671	$ 29,453,980	$ 30,043,059	$ 14,195,325	$ 31,256,799	$ 14,768,816	$ 173,937,990
16	**Total Capital Costs**	**$ 114,385,862**	**$ 126,396,966**	**$ 156,047,612**	**$ 175,545,958**	**$ 137,899,628**	**$ 155,881,108**	**$ 138,587,060**	**$ 1,004,744,194**
17	Amount of Transmission	$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176	$ 30,641,731	$ 213,710,716
18	Amount of Distribution	$ 114,385,862	$ 126,396,966	$ 156,047,612	$ 175,545,958	$ 137,899,628	$ 155,881,108	$ 138,587,060	$ 1,004,744,194
19	**Total Capital Costs**	**$ 136,832,791**	**$ 153,972,404**	**$ 189,729,103**	**$ 211,971,250**	**$ 171,544,287**	**$ 185,176,284**	**$ 169,228,791**	**$ 1,218,454,910**

Indianapolis Power & Light Company
2020 - TDSIC Project Detail - Capital Dollars Only

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	**Age & Condition or Deliverability**	**Project Type**	**project**	**Year**	**Plan Project Cost (Capital Dollars)**	**AACE Cost Estimate**	**Quantity**	**Units**
1	Age & Condition	Circuit Rebuilds	CASTLETON NO. 4	2020	$ [redacted]	Class 2	[redacted]	Miles
2	Age & Condition	Circuit Rebuilds	CENTER NO. 7	2020	$ [redacted]	Class 2	[redacted]	Miles
3	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 6	2020	$ [redacted]	Class 2	[redacted]	Miles
4	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 10	2020	$ [redacted]	Class 2	[redacted]	Miles
5	Age & Condition	Circuit Rebuilds	MAYWOOD NO. 1	2020	$ [redacted]	Class 2	[redacted]	Miles
6	Age & Condition	Circuit Rebuilds	MAYWOOD NO. 2	2020	$ [redacted]	Class 2	[redacted]	Miles
7	Age & Condition	Circuit Rebuilds	MILL ST. NO. 7	2020	$ [redacted]	Class 2	[redacted]	Miles
8	Age & Condition	Circuit Rebuilds	MOORESVILLE NO. 6	2020	$ [redacted]	Class 2	[redacted]	Miles
9	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 3	2020	$ [redacted]	Class 2	[redacted]	Miles
10	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 4	2020	$ [redacted]	Class 2	[redacted]	Miles
11	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 9	2020	$ [redacted]	Class 2	[redacted]	Miles
12	Age & Condition	Circuit Rebuilds	WEST NO. 9	2020	$ [redacted]	Class 2	[redacted]	Miles
13	Age & Condition	Circuit Rebuilds	WESTLANE NO. 7	2020	$ [redacted]	Class 2	[redacted]	Miles
		Circuit Rebuilds Total			$ 27,175,955		[redacted]	
199	Age & Condition	Substation Assets Replacements	BRIDGEPORT	2020	$ [redacted]	Class 2	[redacted]	Units
200	Age & Condition	Substation Assets Replacements	CAMBY	2020	$ [redacted]	Class 2	[redacted]	Units
201	Age & Condition	Substation Assets Replacements	CRAWFORDSVILLE	2020	$ [redacted]	Class 2	[redacted]	Units
202	Age & Condition	Substation Assets Replacements	EDGEWOOD	2020	$ [redacted]	Class 2	[redacted]	Units
203	Age & Condition	Substation Assets Replacements	GARDNER LANE	2020	$ [redacted]	Class 2	[redacted]	Units
204	Age & Condition	Substation Assets Replacements	GEIST	2020	$ [redacted]	Class 2	[redacted]	Units
205	Age & Condition	Substation Assets Replacements	GLENS VALLEY	2020	$ [redacted]	Class 2	[redacted]	Units
206	Age & Condition	Substation Assets Replacements	INDIAN CREEK	2020	$ [redacted]	Class 2	[redacted]	Units
207	Age & Condition	Substation Assets Replacements	LILLY SOUTH	2020	$ [redacted]	Class 2	[redacted]	Units
208	Age & Condition	Substation Assets Replacements	METHODIST HOSPITAL	2020	$ [redacted]	Class 2	[redacted]	Units
209	Age & Condition	Substation Assets Replacements	MONON TRAIL	2020	$ [redacted]	Class 2	[redacted]	Units
210	Age & Condition	Substation Assets Replacements	POST ROAD	2020	$ [redacted]	Class 2	[redacted]	Units
211	Age & Condition	Substation Assets Replacements	RIVER ROAD	2020	$ [redacted]	Class 2	[redacted]	Units
212	Age & Condition	Substation Assets Replacements	ROCKVILLE	2020	$ [redacted]	Class 2	[redacted]	Units
213	Age & Condition	Substation Assets Replacements	SANITATION BELMONT	2020	$ [redacted]	Class 2	[redacted]	Units
214	Age & Condition	Substation Assets Replacements	SHEFFIELD	2020	$ [redacted]	Class 2	[redacted]	Units
215	Age & Condition	Substation Assets Replacements	SOUTHEAST	2020	$ [redacted]	Class 2	[redacted]	Units
216	Age & Condition	Substation Assets Replacements	ST. VINCENT	2020	$ [redacted]	Class 2	[redacted]	Units
217	Age & Condition	Substation Assets Replacements	STOUT GT YARD	2020	$ [redacted]	Class 2	[redacted]	Units
218	Age & Condition	Substation Assets Replacements	TOBEY	2020	$ [redacted]	Class 2	[redacted]	Units
219	Age & Condition	Substation Assets Replacements	UNITED AIRLINES	2020	$ [redacted]	Class 2	[redacted]	Units
220	Age & Condition	Substation Assets Replacements	WILLIAMS ST	2020	$ [redacted]	Class 2	[redacted]	Units
		Substation Assets Replacements Total			$ 16,731,642		[redacted]	
272	Age & Condition	XLPE Cable Replacement	XLPE Cable [redacted] - 2020	2020	$ [redacted]	Class 3	[redacted]	Feet
		XLPE Cable Replacement Total			$ 12,185,638			

Indianapolis Power & Light Company
2020 - TDSIC Project Detail - Capital Dollars Only

Line No.	(A) Age & Condition or Deliverability	(B) Project Type	(C) project	(D) Year	(E) Plan Project Cost (Capital Dollars)	(F) AACE Cost Estimate	(G) Quantity	(H) Units
279	Age & Condition	4 kV Conversion	CONVERT KRISTEN TIE	2020	$ [redacted]	Class 2	[redacted]	Units
280	Age & Condition	4 kV Conversion	CONVERT MUNTER	2020	$ [redacted]	Class 2	[redacted]	Units
281	Age & Condition	4 kV Conversion	CONVERT KILDARE TIE	2020	$ [redacted]	Class 2	[redacted]	Units
282	Age & Condition	4 kV Conversion	CONVERT VERNON ACRES TIE	2020	$ [redacted]	Class 2	[redacted]	Units
283	Age & Condition	4 kV Conversion	CONVERT MARDENNA	2020	$ [redacted]	Class 2	[redacted]	Units
284	Age & Condition	4 kV Conversion	CONVERT FOREST MANOR TIE	2020	$ [redacted]	Class 2	[redacted]	Units
		4 kV Conversion Total			$ 19,709,314			
324	Age & Condition	Tap Reliability Improvement Projects	Lawrence # 3 (345B-91)	2020	$ [redacted]	Class 2	[redacted]	Units
325	Age & Condition	Tap Reliability Improvement Projects	Post Rd #7 (281-B-6)	2020	$ [redacted]	Class 2	[redacted]	Units
326	Age & Condition	Tap Reliability Improvement Projects	Pike #3 (395-A-6)	2020	$ [redacted]	Class 2	[redacted]	Units
327	Age & Condition	Tap Reliability Improvement Projects	Mootsville #4 (M20-X-6)	2020	$ [redacted]	Class 2	[redacted]	Units
328	Age & Condition	Tap Reliability Improvement Projects	Lafayette #5 252-3,6	2020	$ [redacted]	Class 2	[redacted]	Units
329	Age & Condition	Tap Reliability Improvement Projects	Northeast # 6 (340-A-159)	2020	$ [redacted]	Class 2	[redacted]	Units
330	Age & Condition	Tap Reliability Improvement Projects	Parker #2 (260-B-192)	2020	$ [redacted]	Class 2	[redacted]	Units
331	Age & Condition	Tap Reliability Improvement Projects	Northeast #11 (372-72)	2020	$ [redacted]	Class 2	[redacted]	Units
332	Age & Condition	Tap Reliability Improvement Projects	Geist #4 (P109-208-B)	2020	$ [redacted]	Class 2	[redacted]	Units
333	Age & Condition	Tap Reliability Improvement Projects	Tremont #12 (4-200-B)	2020	$ [redacted]	Class 2	[redacted]	Units
334	Age & Condition	Tap Reliability Improvement Projects	Geist #6 (221-B)	2020	$ [redacted]	Class 2	[redacted]	Units
335	Age & Condition	Tap Reliability Improvement Projects	Parker #6 (315-39)	2020	$ [redacted]	Class 2	[redacted]	Units
336	Age & Condition	Tap Reliability Improvement Projects	Guion #8 (360-A-196)	2020	$ [redacted]	Class 2	[redacted]	Units
337	Age & Condition	Tap Reliability Improvement Projects	Guion #8 (12-360-A)	2020	$ [redacted]	Class 2	[redacted]	Units
338	Age & Condition	Tap Reliability Improvement Projects	Guion #8 (361-B-101)	2020	$ [redacted]	Class 2	[redacted]	Units
339	Age & Condition	Tap Reliability Improvement Projects	Northeast #11 (372-141)	2020	$ [redacted]	Class 2	[redacted]	Units
340	Age & Condition	Tap Reliability Improvement Projects	Tobey #7 (420-B-45)	2020	$ [redacted]	Class 2	[redacted]	Units
341	Age & Condition	Tap Reliability Improvement Projects	South #6 (700-A-140)	2020	$ [redacted]	Class 2	[redacted]	Units
342	Age & Condition	Tap Reliability Improvement Projects	Castleton #4 (P62-245-B)	2020	$ [redacted]	Class 2	[redacted]	Units
343	Age & Condition	Tap Reliability Improvement Projects	Castleton #4 (P117-245-B)	2020	$ [redacted]	Class 2	[redacted]	Units
		Tap Reliability Improvement Projects Total			$ 10,896,034			
350	Age & Condition	Meter Replacement	Meter Replacement - 2020	2020	$ [redacted]	Class 3	[redacted]	Meters
		Meter Replacement Total			$ 10,735,674			
355	Age & Condition	CBD Secondary Network Upgrades	Pierson #1	2020	$ [redacted]	Class 2	[redacted]	Units
356	Age & Condition	CBD Secondary Network Upgrades	DAS Route 1	2020	$ [redacted]	Class 2	[redacted]	Units
357	Age & Condition	CBD Secondary Network Upgrades	Feeder 621 Cable Replacement	2020	$ [redacted]	Class 2	[redacted]	Units
358	Age & Condition	CBD Secondary Network Upgrades	36 W Vermont Vault Upgrade	2020	$ [redacted]	Class 2	[redacted]	Units
359	Age & Condition	CBD Secondary Network Upgrades	431 N Penn Vault Upgrade	2020	$ [redacted]	Class 2	[redacted]	Units
360	Age & Condition	CBD Secondary Network Upgrades	Pierson #2	2020	$ [redacted]	Class 2	[redacted]	Units
361	Age & Condition	CBD Secondary Network Upgrades	Pierson #3	2020	$ [redacted]	Class 2	[redacted]	Units
		CBD Secondary Network Upgrades Total			$ 4,585,019			
510	Age & Condition	Static Wire Performance Improvement	132-44 Crestview - Northeast	2020	$ [redacted]	Class 2	[redacted]	Miles

Indianapolis Power & Light Company
2020 - TDSIC Project Detail - Capital Dollars Only

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
511	Age & Condition	Static Wire Performance Improvement	132-84 Mooresville - Camby	2020	$ [redacted]	Class 2	[redacted]	Miles
512	Age & Condition	Static Wire Performance Improvement	132-24 MV Tap Switch - Mooresville	2020	$ [redacted]	Class 2	[redacted]	Miles
		Static Wire Performance Improvement Total			$ 4,765,917			
535	Age & Condition	Remote End - Breaker Relay/Upgrades	CASTLETON-132-54 BKR - Relay	2020	$ [redacted]	Class 2	[redacted]	Units
536	Age & Condition	Remote End - Breaker Relay/Upgrades	CASTLETON-132-55 BKR - Relay	2020	$ [redacted]	Class 2	[redacted]	Units
537	Age & Condition	Remote End - Breaker Relay/Upgrades	MILL STREET-132-65 LINE BKR - Relay	2020	$ [redacted]	Class 2	[redacted]	Units
538	Age & Condition	Remote End - Breaker Relay/Upgrades	SUNNYSIDE-132-46 BKR - Relay	2020	$ [redacted]	Class 2	[redacted]	Units
539	Age & Condition	Remote End - Breaker Relay/Upgrades	SANITATION BLMT-138 BUSTIE OCB - Breaker	2020	$ [redacted]	Class 2	[redacted]	Units
540	Age & Condition	Remote End - Breaker Relay/Upgrades	ROCKVILLE-132-64 BKR - Breaker	2020	$ [redacted]	Class 2	[redacted]	Units
541	Age & Condition	Remote End - Breaker Relay/Upgrades	GLENS VALLEY-BUS TIE BKR - Breaker	2020	$ [redacted]	Class 2	[redacted]	Units
		Remote End - Breaker Relay/Upgrades Total			$ 3,042,255			
590	Age & Condition	Pole Replacements	Pole Replacement - 2020	2020	$ [redacted]	Class 3	[redacted]	Poles
591	Age & Condition	Pole Replacements	Pole Treatment - 2020	2020	$ [redacted]	Class 3	[redacted]	Poles
		Pole Replacements Total			$ 3,256,334			
604	Age & Condition	Steel Tower Life Extension	Steel Tower Life Extension - 2020	2020	$ [redacted]	Class 3	[redacted]	Structures
		Steel Tower Life Extension Total			$ 1,138,320			
608	Deliverability	Distribution Automation	Reclosers - 2020	2020	$ [redacted]	Class 4	[redacted]	Reclosers
615	Deliverability	Distribution Automation	Advanced Distribution Management System - 2020	2020	$ [redacted]	Class 3	[redacted]	Units
		Distribution Automation Total			$ 18,815,340			
617	Deliverability	Substation Design Upgrades	Rockville Sub - Add Breaker & Create Ring Bus	2020	$ [redacted]	Class 2	[redacted]	Units
618	Deliverability	Substation Design Upgrades	Prospect - Add 138kv Breaker	2020	$ [redacted]	Class 2	[redacted]	Units
		Substation Design Upgrades Total			$ 3,795,549			
		Grand Total			$ 136,832,791			

Indianapolis Power & Light Company
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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
14	Age & Condition	Circuit Rebuilds	CENTER NO. 3	2021	$ [redacted]	Class 2	[redacted]	Miles
15	Age & Condition	Circuit Rebuilds	CENTER NO. 6	2021	$ [redacted]	Class 2	[redacted]	Miles
16	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 1	2021	$ [redacted]	Class 2	[redacted]	Miles
17	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 3	2021	$ [redacted]	Class 2	[redacted]	Miles
18	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 8	2021	$ [redacted]	Class 2	[redacted]	Miles
19	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 3	2021	$ [redacted]	Class 2	[redacted]	Miles
20	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 4	2021	$ [redacted]	Class 2	[redacted]	Miles
21	Age & Condition	Circuit Rebuilds	MILL ST. NO. 4	2021	$ [redacted]	Class 2	[redacted]	Miles
22	Age & Condition	Circuit Rebuilds	MILL ST. NO. 9	2021	$ [redacted]	Class 2	[redacted]	Miles
23	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 1	2021	$ [redacted]	Class 2	[redacted]	Miles
24	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 2	2021	$ [redacted]	Class 2	[redacted]	Miles
25	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 1	2021	$ [redacted]	Class 2	[redacted]	Miles
26	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 3	2021	$ [redacted]	Class 2	[redacted]	Miles
27	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 5	2021	$ [redacted]	Class 2	[redacted]	Miles
28	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 7	2021	$ [redacted]	Class 2	[redacted]	Miles
29	Age & Condition	Circuit Rebuilds	WEST NO. 2	2021	$ [redacted]	Class 2	[redacted]	Miles
30	Age & Condition	Circuit Rebuilds	WEST NO. 10	2021	$ [redacted]	Class 2	[redacted]	Miles
		Circuit Rebuilds Total			$ 25,345,895		[redacted]	
221	Age & Condition	Substation Assets Replacements	ALLISON #4	2021	$ [redacted]	Class 2	[redacted]	Units
222	Age & Condition	Substation Assets Replacements	CENTER	2021	$ [redacted]	Class 2	[redacted]	Units
223	Age & Condition	Substation Assets Replacements	CRESTVIEW	2021	$ [redacted]	Class 2	[redacted]	Units
224	Age & Condition	Substation Assets Replacements	EDISON	2021	$ [redacted]	Class 2	[redacted]	Units
225	Age & Condition	Substation Assets Replacements	GUION	2021	$ [redacted]	Class 2	[redacted]	Units
226	Age & Condition	Substation Assets Replacements	HANNA	2021	$ [redacted]	Class 2	[redacted]	Units
227	Age & Condition	Substation Assets Replacements	I.C.E.	2021	$ [redacted]	Class 2	[redacted]	Units
228	Age & Condition	Substation Assets Replacements	I.U.CAMPUS SOUTH	2021	$ [redacted]	Class 2	[redacted]	Units
229	Age & Condition	Substation Assets Replacements	LILLY CORP	2021	$ [redacted]	Class 2	[redacted]	Units
230	Age & Condition	Substation Assets Replacements	MOORESVILLE	2021	$ [redacted]	Class 2	[redacted]	Units
231	Age & Condition	Substation Assets Replacements	PARK FLETCHER	2021	$ [redacted]	Class 2	[redacted]	Units
232	Age & Condition	Substation Assets Replacements	QUEMETCO	2021	$ [redacted]	Class 2	[redacted]	Units
233	Age & Condition	Substation Assets Replacements	WATER CO WHITE RIV IND SUB	2021	$ [redacted]	Class 2	[redacted]	Units
234	Age & Condition	Substation Assets Replacements	WESTLANE	2021	$ [redacted]	Class 2	[redacted]	Units
		Substation Assets Replacements Total			$ 27,023,779		[redacted]	
273	Age & Condition	XLPE Cable Replacement	**XLPE Cable Replacements - 2021**	2021	$ [redacted]	Class 3	[redacted]	Feet
		XLPE Cable Replacement Total			$ 11,768,208		[redacted]	
285	Age & Condition	4 kV Conversion	CONVERT MILLERSVILLE TIE	2021	$ [redacted]	Class 2	[redacted]	Units
286	Age & Condition	4 kV Conversion	CONVERT GALE TIE	2021	$ [redacted]	Class 2	[redacted]	Units
287	Age & Condition	4 kV Conversion	CONVERT EUCLID TIE	2021	$ [redacted]	Class 2	[redacted]	Units
288	Age & Condition	4 kV Conversion	CONVERT STUART	2021	$ [redacted]	Class 2	[redacted]	Units

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
		4 kV Conversion Total			$ 13,824,925			
344	Age & Condition	Tap Reliability Improvement Projects	TRIP - 2021	2021	$ [redacted]	Class 4	[redacted]	Units
		Tap Reliability Improvement Projects Total			$ 10,404,000		[redacted]	
351	Age & Condition	Meter Replacement	Meter Replacement - 2021	2021	$ [redacted]	Class 3	[redacted]	Meters
		Meter Replacement Total			$ 10,550,388		[redacted]	
362	Age & Condition	CBD Secondary Network Upgrades	128 W Georgia St Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
363	Age & Condition	CBD Secondary Network Upgrades	Feeder 661 Cable Replacement	2021	$ [redacted]	Class 2	[redacted]	Units
364	Age & Condition	CBD Secondary Network Upgrades	Feeder 451 Cable Replacement	2021	$ [redacted]	Class 2	[redacted]	Units
365	Age & Condition	CBD Secondary Network Upgrades	Feeder 461 Cable Replacement	2021	$ [redacted]	Class 2	[redacted]	Units
366	Age & Condition	CBD Secondary Network Upgrades	25 W Georgia St. Vault Upgr	2021	$ [redacted]	Class 2	[redacted]	Units
367	Age & Condition	CBD Secondary Network Upgrades	19 N. Meridian St. Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
368	Age & Condition	CBD Secondary Network Upgrades	215 W. New York St. Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
369	Age & Condition	CBD Secondary Network Upgrades	108 E Market St Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
370	Age & Condition	CBD Secondary Network Upgrades	121 Monument Circle Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
371	Age & Condition	CBD Secondary Network Upgrades	108 E Maryland St Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
372	Age & Condition	CBD Secondary Network Upgrades	150 E Market St Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
373	Age & Condition	CBD Secondary Network Upgrades	26 E Ohio St Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
374	Age & Condition	CBD Secondary Network Upgrades	110 N Scioto St Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
375	Age & Condition	CBD Secondary Network Upgrades	Pierson #6	2021	$ [redacted]	Class 2	[redacted]	Units
376	Age & Condition	CBD Secondary Network Upgrades	Pierson #5	2021	$ [redacted]	Class 2	[redacted]	Units
377	Age & Condition	CBD Secondary Network Upgrades	117 E Michigan St Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
378	Age & Condition	CBD Secondary Network Upgrades	Pierson #4	2021	$ [redacted]	Class 2	[redacted]	Units
379	Age & Condition	CBD Secondary Network Upgrades	OTS Route 1 Extension	2021	$ [redacted]	Class 2	[redacted]	Units
		CBD Secondary Network Upgrades Total			$ 5,918,264		[redacted]	
513	Age & Condition	Static Wire Performance Improvement	132-35 Pike - Crawfordsville Rd	2021	$ [redacted]	Class 2	[redacted]	Miles
514	Age & Condition	Static Wire Performance Improvement	132-05 Stout - Glenns Valley	2021	$ [redacted]	Class 2	[redacted]	Miles
515	Age & Condition	Static Wire Performance Improvement	132-59 Southwest - Sanitation Southport	2021	$ [redacted]	Class 2	[redacted]	Miles
516	Age & Condition	Static Wire Performance Improvement	132-70 Allison #4 - West	2021	$ [redacted]	Class 2	[redacted]	Miles
517	Age & Condition	Static Wire Performance Improvement	132-61 Center - Lilly South	2021	$ [redacted]	Class 2	[redacted]	Miles
518	Age & Condition	Static Wire Performance Improvement	2451-1 Center - Lilly Corp	2021	$ [redacted]	Class 2	[redacted]	Miles
		Static Wire Performance Improvement Total			$ 6,881,909		[redacted]	
542	Age & Condition	Remote End - Breaker Relay/Upgrades	LILLY-SOUTH-132-61 BKR - Relay	2021	$ [redacted]	Class 2	[redacted]	Units
543	Age & Condition	Remote End - Breaker Relay/Upgrades	LILLY CORP-2451-1 BKR - Relay	2021	$ [redacted]	Class 2	[redacted]	Units
544	Age & Condition	Remote End - Breaker Relay/Upgrades	ENGLISH AVE-2471-1 BREAKER - Relay	2021	$ [redacted]	Class 2	[redacted]	Units
545	Age & Condition	Remote End - Breaker Relay/Upgrades	STOUT SOUTH YARD - Relay	2021	$ [redacted]	Class 2	[redacted]	Units
546	Age & Condition	Remote End - Breaker Relay/Upgrades	I.C.E.-BUS TIE BREAKER - Relay	2021	$ [redacted]	Class 2	[redacted]	Units
547	Age & Condition	Remote End - Breaker Relay/Upgrades	CRESTVIEW-138KV BUS TIE BKR - Breaker & Relay	2021	$ [redacted]	Class 2	[redacted]	Units
548	Age & Condition	Remote End - Breaker Relay/Upgrades	WEST-132-70W BKR - Relay	2021	$ [redacted]	Class 2	[redacted]	Units
549	Age & Condition	Remote End - Breaker Relay/Upgrades	WEST-132-63 BKR - Relay	2021	$ [redacted]	Class 2	[redacted]	Units

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
		Remote End - Breaker Relay/Upgrades Total			$ 2,017,899		[redacted]	
592	Age & Condition	Pole Replacements	Pole Replacement - 2021	2021	$ [redacted]	Class 3	[redacted]	Poles
593	Age & Condition	Pole Replacements	Pole Treatment - 2021	2021	$ [redacted]	Class 3	[redacted]	Poles
		Pole Replacements Total			$ 3,321,256		[redacted]	
605	Age & Condition	Steel Tower Life Extension	Steel Tower Life Extension - 2021	2021	$ [redacted]	Class 3	[redacted]	Structures
		Steel Tower Life Extension Total			$ 1,111,147		[redacted]	
609	Deliverability	Distribution Automation	Reclosers - 2021	2021	$ [redacted]	Class 4	[redacted]	Reclosers
616	Deliverability	Distribution Automation	Advanced Distribution Management System - 2021	2021	$ [redacted]	Class 3	[redacted]	Units
		Distribution Automation Total			$ 19,191,646		[redacted]	
619	Deliverability	Substation Design Upgrades	Center Sub - Rebuild and Reconfigure	2021	$ [redacted]	Class 2	[redacted]	Units
620	Deliverability	Substation Design Upgrades	Mooresville - Sub Reconfigure	2021	$ [redacted]	Class 2	[redacted]	Units
		Substation Design Upgrades Total			$ 16,213,025			
		Grand Total			$ 193,972,404			

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	(A)	(B)	(C)	(D)	(E)		(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (C[redacted]		AACE Cost Estimate	Quantity	Units
31	Age & Condition	Circuit Rebuilds	CENTER NO. 8	2022	$	[redacted]	Class 4	[redacted]	Miles
32	Age & Condition	Circuit Rebuilds	CENTER NO. 10	2022	$	[redacted]	Class 4	[redacted]	Miles
33	Age & Condition	Circuit Rebuilds	EAST NO. 1	2022	$	[redacted]	Class 4	[redacted]	Miles
34	Age & Condition	Circuit Rebuilds	EDGEWOOD NO. 9	2022	$	[redacted]	Class 4	[redacted]	Miles
35	Age & Condition	Circuit Rebuilds	GERMAN CHURCH NO. 9	2022	$	[redacted]	Class 4	[redacted]	Miles
36	Age & Condition	Circuit Rebuilds	GUION NO. 5	2022	$	[redacted]	Class 4	[redacted]	Miles
37	Age & Condition	Circuit Rebuilds	GUION NO. 6	2022	$	[redacted]	Class 4	[redacted]	Miles
38	Age & Condition	Circuit Rebuilds	GUION NO. 7	2022	$	[redacted]	Class 4	[redacted]	Miles
39	Age & Condition	Circuit Rebuilds	INDIAN CREEK NO. 3	2022	$	[redacted]	Class 4	[redacted]	Miles
40	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 8	2022	$	[redacted]	Class 4	[redacted]	Miles
41	Age & Condition	Circuit Rebuilds	MILL ST. NO. 1	2022	$	[redacted]	Class 4	[redacted]	Miles
42	Age & Condition	Circuit Rebuilds	MILL ST. NO. 3	2022	$	[redacted]	Class 4	[redacted]	Miles
43	Age & Condition	Circuit Rebuilds	MILL ST. NO. 5	2022	$	[redacted]	Class 4	[redacted]	Miles
44	Age & Condition	Circuit Rebuilds	MONON TRAIL NO. 1	2022	$	[redacted]	Class 4	[redacted]	Miles
45	Age & Condition	Circuit Rebuilds	MONROVIA NO. 1	2022	$	[redacted]	Class 4	[redacted]	Miles
46	Age & Condition	Circuit Rebuilds	MOORESVILLE NO. 1	2022	$	[redacted]	Class 4	[redacted]	Miles
47	Age & Condition	Circuit Rebuilds	NORTH NO. 2	2022	$	[redacted]	Class 4	[redacted]	Miles
48	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 12	2022	$	[redacted]	Class 4	[redacted]	Miles
49	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 2	2022	$	[redacted]	Class 4	[redacted]	Miles
50	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 4	2022	$	[redacted]	Class 4	[redacted]	Miles
51	Age & Condition	Circuit Rebuilds	PARK FLETCHER NO. 4	2022	$	[redacted]	Class 4	[redacted]	Miles
52	Age & Condition	Circuit Rebuilds	PARKER NO. 2	2022	$	[redacted]	Class 4	[redacted]	Miles
53	Age & Condition	Circuit Rebuilds	PROSPECT NO. 5	2022	$	[redacted]	Class 4	[redacted]	Miles
54	Age & Condition	Circuit Rebuilds	QUEMETCO NO. 1	2022	$	[redacted]	Class 4	[redacted]	Miles
55	Age & Condition	Circuit Rebuilds	RCA E 30TH NO. 1	2022	$	[redacted]	Class 4	[redacted]	Miles
56	Age & Condition	Circuit Rebuilds	RCA E 30TH NO. 2	2022	$	[redacted]	Class 4	[redacted]	Miles
57	Age & Condition	Circuit Rebuilds	RIVER ROAD NO. 5	2022	$	[redacted]	Class 4	[redacted]	Miles
58	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 2	2022	$	[redacted]	Class 4	[redacted]	Miles
59	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 4	2022	$	[redacted]	Class 4	[redacted]	Miles
60	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 7	2022	$	[redacted]	Class 4	[redacted]	Miles
61	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 8	2022	$	[redacted]	Class 4	[redacted]	Miles
62	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 9	2022	$	[redacted]	Class 4	[redacted]	Miles
63	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 10	2022	$	[redacted]	Class 4	[redacted]	Miles
64	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 16	2022	$	[redacted]	Class 4	[redacted]	Miles
65	Age & Condition	Circuit Rebuilds	SHEFFIELD NO. 2	2022	$	[redacted]	Class 4	[redacted]	Miles
66	Age & Condition	Circuit Rebuilds	SHEFFIELD NO. 4	2022	$	[redacted]	Class 4	[redacted]	Miles
67	Age & Condition	Circuit Rebuilds	SHEFFIELD NO. 5	2022	$	[redacted]	Class 4	[redacted]	Miles
68	Age & Condition	Circuit Rebuilds	SOUTH NO. 4	2022	$	[redacted]	Class 4	[redacted]	Miles
69	Age & Condition	Circuit Rebuilds	SOUTH NO. 6	2022	$	[redacted]	Class 4	[redacted]	Miles

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	**Age & Condition or Deliverability**	**Project Type**	**project**	**Year**	**Plan Project Cost (Capital Dollars)**	**AACE Cost Estimate**	**Quantity**	**Units**
70	Age & Condition	Circuit Rebuilds	SOUTH NO. 10	2022	$ [redacted]	Class 4	[redacted]	Miles
71	Age & Condition	Circuit Rebuilds	SOUTHPORT NO. 6	2022	$ [redacted]	Class 4	[redacted]	Miles
72	Age & Condition	Circuit Rebuilds	THOMPSON NO. 3	2022	$ [redacted]	Class 4	[redacted]	Miles
73	Age & Condition	Circuit Rebuilds	THOMPSON NO. 5	2022	$ [redacted]	Class 4	[redacted]	Miles
74	Age & Condition	Circuit Rebuilds	TOBEY NO. 7	2022	$ [redacted]	Class 4	[redacted]	Miles
75	Age & Condition	Circuit Rebuilds	TOBEY NO. 10	2022	$ [redacted]	Class 4	[redacted]	Miles
76	Age & Condition	Circuit Rebuilds	TREMONT NO. 2	2022	$ [redacted]	Class 4	[redacted]	Miles
77	Age & Condition	Circuit Rebuilds	TREMONT NO. 7	2022	$ [redacted]	Class 4	[redacted]	Miles
78	Age & Condition	Circuit Rebuilds	TREMONT NO. 10	2022	$ [redacted]	Class 4	[redacted]	Miles
79	Age & Condition	Circuit Rebuilds	WEST NO. 1	2022	$ [redacted]	Class 4	[redacted]	Miles
80	Age & Condition	Circuit Rebuilds	WILLIAMS NO. 2	2022	$ [redacted]	Class 4	[redacted]	Miles
81	Age & Condition	Circuit Rebuilds	WILLIAMS NO. 5	2022	$ [redacted]	Class 4	[redacted]	Miles
		Circuit Rebuilds Total			$ 45,810,667		[redacted]	
235	Age & Condition	Substation Assets Replacements	CASTLETON	2022	$ [redacted]	Class 4	[redacted]	Units
236	Age & Condition	Substation Assets Replacements	CUMBERLAND	2022	$ [redacted]	Class 4	[redacted]	Units
237	Age & Condition	Substation Assets Replacements	GEORGETOWN	2022	$ [redacted]	Class 4	[redacted]	Units
238	Age & Condition	Substation Assets Replacements	GERMAN CHURCH	2022	$ [redacted]	Class 4	[redacted]	Units
239	Age & Condition	Substation Assets Replacements	LAFAYETTE ROAD	2022	$ [redacted]	Class 4	[redacted]	Units
240	Age & Condition	Substation Assets Replacements	DOW ELANCO	2022	$ [redacted]	Class 4	[redacted]	Units
241	Age & Condition	Substation Assets Replacements	I.U. MED. CENTER	2022	$ [redacted]	Class 4	[redacted]	Units
242	Age & Condition	Substation Assets Replacements	ROACH CHEM.	2022	$ [redacted]	Class 4	[redacted]	Units
243	Age & Condition	Substation Assets Replacements	STOUT	2022	$ [redacted]	Class 4	[redacted]	Units
244	Age & Condition	Substation Assets Replacements	PETERSBURG	2022	$ [redacted]	Class 4	[redacted]	Units
245	Age & Condition	Substation Assets Replacements	PIKE	2022	$ [redacted]	Class 4	[redacted]	Units
246	Age & Condition	Substation Assets Replacements	STOUT SOUTH YARD	2022	$ [redacted]	Class 4	[redacted]	Units
247	Age & Condition	Substation Assets Replacements	THOMPSON	2022	$ [redacted]	Class 4	[redacted]	Units
248	Age & Condition	Substation Assets Replacements	TREMONT	2022	$ [redacted]	Class 4	[redacted]	Units
		Substation Assets Replacements Total			$ 39,896,631		[redacted]	
274	Age & Condition	XLPE Cable Replacement	**XLPE Cable Replacements - 2022**	2022	$ [redacted]	Class 4	[redacted]	Feet
		XLPE Cable Replacement Total			$ 12,501,788		[redacted]	
289	Age & Condition	4 kV Conversion	CONVERT DOUGLAS	2022	$ [redacted]	Class 4	[redacted]	Units
290	Age & Condition	4 kV Conversion	CONVERT SANGSTER	2022	$ [redacted]	Class 4	[redacted]	Units
291	Age & Condition	4 kV Conversion	CONVERT FLAKE	2022	$ [redacted]	Class 4	[redacted]	Units
292	Age & Condition	4 kV Conversion	CONVERT OXFORD	2022	$ [redacted]	Class 4	[redacted]	Units
293	Age & Condition	4 kV Conversion	CONVERT CAROLINE TIE	2022	$ [redacted]	Class 4	[redacted]	Units
294	Age & Condition	4 kV Conversion	CONVERT CAROLINE - EMER	2022	$ [redacted]	Class 4	[redacted]	Units
295	Age & Condition	4 kV Conversion	CONVERT RALSTON	2022	$ [redacted]	Class 4	[redacted]	Units
		4 kV Conversion Total			$ 15,422,783		[redacted]	
345	Age & Condition	Tap Reliability Improvement Projects	TRIP - 2022	2022	$ [redacted]	Class 4	[redacted]	Units

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	(A)	(B)	(C)	(D)		(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year		Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
		Tap Reliability Improvement Projects Total			$	10,612,080		[redacted]	
352	Age & Condition	Meter Replacement	Meter Replacement - 2022	2022	$	[redacted]	Class 4		Meters
		Meter Replacement Total			$	11,169,395			
380	Age & Condition	CBD Secondary Network Upgrades	New Pre-Cast Manhole (Location vic. Pierson and Michigan)	2022	$	[redacted]	Class 4		Units
381	Age & Condition	CBD Secondary Network Upgrades	New Pre-Cast Manhole (Location vic. Illinois and Michigan)	2022	$		Class 4		Units
382	Age & Condition	CBD Secondary Network Upgrades	New Pre-Cast Manhole (Location vic. 535 N. Illinois)	2022	$		Class 4		Units
383	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH I15-11	2022	$		Class 4		Units
384	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH I15-00	2022	$		Class 4		Units
385	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH I16-02	2022	$		Class 4		Units
386	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH I16-03	2022	$		Class 4		Units
387	Age & Condition	CBD Secondary Network Upgrades	Duct Line WR1 (186 ft.) Location vic. Pierson and Michigan	2022	$		Class 4		Units
388	Age & Condition	CBD Secondary Network Upgrades	Duct Line WR2 (67 ft.) Location vic. Illinois and Michigan	2022	$		Class 4		Units
389	Age & Condition	CBD Secondary Network Upgrades	Duct Line WR3 (239 ft.) Location vic. Illinois and Michigan	2022	$		Class 4		Units
390	Age & Condition	CBD Secondary Network Upgrades	Duct Line WR4 (110 ft.) Location vic. 535 N. Illinois	2022	$		Class 4		Units
391	Age & Condition	CBD Secondary Network Upgrades	Duct Line WR5 (294 ft.) Location vic. Pierson and Michigan	2022	$		Class 4		Units
392	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 108 E. Market, UG412	2022	$		Class 4		Units
393	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 121 Monument Circle, UG422	2022	$		Class 4		Units
394	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 128 W. Georgia, UG 641	2022	$		Class 4		Units
395	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG462 108 E. Market	2022	$		Class 4		Units
396	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG422 121 Monument Circle	2022	$		Class 4		Units
397	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG432 2 W. Washington	2022	$		Class 4		Units
398	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, 317 W. Michigan	2022	$		Class 4		Units
399	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 573 ft) MH I15-00 to MH I16-02	2022	$		Class 4		Units
400	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 907 ft) MH I15-01 to MH I15-97	2022	$		Class 4		Units
401	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 1128 ft) MH I15-07 to MH I14-00	2022	$		Class 4		Units
402	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cicuit 631 (Length 1,924 ft)	2022	$		Class 4		Units
403	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Edison Circuit 453 (Length 4,612 ft)	2022	$		Class 4		Units
404	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable with Manholes (Length 1,294 ft) MH in Year	2022	$		Class 4		Units
405	Age & Condition	CBD Secondary Network Upgrades	Real Time DTS Monitoring (Mass. Ave. network Quadrant)	2022	$		Class 4		Units
406	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 400 W. Washington, 44 N. Senate	2022	$		Class 4		Units
407	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 110 N. Senate, 46 N. Capital	2022	$		Class 4		Units
408	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 320 W. Washington, 309 W. Washington	2022	$		Class 4		Units
409	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 10 S. Capital, 202 W. Maryland, 128 W. Georgia	2022	$		Class 4		Units
		CBD Secondary Network Upgrades Total			$	5,311,051			
519	Age & Condition	Static Wire Performance Improvement	132-36 Edison - Brookwood	2022	$	[redacted]	Class 4		Miles
520	Age & Condition	Static Wire Performance Improvement	132-41 Westlane - Georgetown	2022	$		Class 4		Miles
521	Age & Condition	Static Wire Performance Improvement	132-28 Prospect - Ford	2022	$		Class 4		Miles
		Static Wire Performance Improvement Total			$	9,502,181			
550	Age & Condition	Remote End - Breaker Relay/Upgrades	GLENS VALLEY-BUS TIE BKR - Relay	2022	$	[redacted]	Class 4		Units

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	(A)	(B)	(C)	(D)	(E)		(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)		AACE Cost Estimate	Quantity	Units
551	Age & Condition	Remote End - Breaker Relay/Upgrades	IU CAMPUS N-3331-1 BKR - Relay	2022	$	[redacted]	Class 4	[redacted]	Units
552	Age & Condition	Remote End - Breaker Relay/Upgrades	LAWRENCE-132-48 BREAKER - Breaker	2022	$	[redacted]	Class 4	[redacted]	Units
553	Age & Condition	Remote End - Breaker Relay/Upgrades	STOUT N-132-14 WEST OCB - Breaker	2023	$	[redacted]	Class 4	[redacted]	Units
554	Age & Condition	Remote End - Breaker Relay/Upgrades	STOUT N-132-14 EAST OCB - Breaker & Relay	2022	$	[redacted]	Class 4	[redacted]	Units
555	Age & Condition	Remote End - Breaker Relay/Upgrades	MILL STREET-132-65 LINE BKR. - Breaker	2022	$	[redacted]	Class 4	[redacted]	Units
556	Age & Condition	Remote End - Breaker Relay/Upgrades	STOUT N-138-99 EAST OCB - Breaker & Relay	2022	$	[redacted]	Class 4	[redacted]	Units
557	Age & Condition	Remote End - Breaker Relay/Upgrades	STOUT N-138-99 WEST OCB - Breaker	2022	$	[redacted]	Class 4	[redacted]	Units
		Remote End - Breaker Relay/Upgrades Total			$	5,578,433		[redacted]	
564	Age & Condition	Pole Replacements	Pole Replacement - 2022	2022	$	[redacted]	Class 4	[redacted]	Poles
565	Age & Condition	Pole Replacements	Pole Treatment - 2022	2022	$	[redacted]	Class 4	[redacted]	Poles
		Pole Replacements Total			$	3,387,682		[redacted]	
606	Age & Condition	Steel Tower Life Extension	Steel Tower Life Extension - 2022	2022	$	[redacted]	Class 4	[redacted]	Structures
		Steel Tower Life Extension Total			$	1,082,432		[redacted]	
610	Deliverability	Distribution Automation	Reclosers - 2022	2022	$	[redacted]	Class 4	[redacted]	Reclosers
		Distribution Automation Total			$	13,644,103		[redacted]	
621	Deliverability	Substation Design Upgrades	New 13.2kv Sub for 4kv Conversion	2022	$	[redacted]	Class 4	[redacted]	Units
		Substation Design Upgrades Total			$	15,809,877		[redacted]	
		Grand Total			$	189,729,103			

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	(A)	(B)	(C)	(D)	(E)		(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)		AACE Cost Estimate	Quantity	Units
82	Age & Condition	Circuit Rebuilds	CASTLETON NO. 7	2023	$	[redacted]	Class 4	[redacted]	Miles
83	Age & Condition	Circuit Rebuilds	CASTLETON NO. 8	2023	$	[redacted]	Class 4	[redacted]	Miles
84	Age & Condition	Circuit Rebuilds	CASTLETON NO. 17	2023	$	[redacted]	Class 4	[redacted]	Miles
85	Age & Condition	Circuit Rebuilds	CRAWFORDSVILLE NO. 2	2023	$	[redacted]	Class 4	[redacted]	Miles
86	Age & Condition	Circuit Rebuilds	EAST NO. 4	2023	$	[redacted]	Class 4	[redacted]	Miles
87	Age & Condition	Circuit Rebuilds	EAST NO. 8	2023	$	[redacted]	Class 4	[redacted]	Miles
88	Age & Condition	Circuit Rebuilds	EDGEWOOD NO. 5	2023	$	[redacted]	Class 4	[redacted]	Miles
89	Age & Condition	Circuit Rebuilds	FRANKLIN TWNSHP NO. 2	2023	$	[redacted]	Class 4	[redacted]	Miles
90	Age & Condition	Circuit Rebuilds	GERMAN CHURCH NO. 4	2023	$	[redacted]	Class 4	[redacted]	Miles
91	Age & Condition	Circuit Rebuilds	GLENNS VALLEY NO. 2	2023	$	[redacted]	Class 4	[redacted]	Miles
92	Age & Condition	Circuit Rebuilds	LAFAYETTE ROAD NO. 3	2023	$	[redacted]	Class 4	[redacted]	Miles
93	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 1	2023	$	[redacted]	Class 4	[redacted]	Miles
94	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 6	2023	$	[redacted]	Class 4	[redacted]	Miles
95	Age & Condition	Circuit Rebuilds	MOORESVILLE NO. 3	2023	$	[redacted]	Class 4	[redacted]	Miles
96	Age & Condition	Circuit Rebuilds	NORTH NO. 4	2023	$	[redacted]	Class 4	[redacted]	Miles
97	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 6	2023	$	[redacted]	Class 4	[redacted]	Miles
98	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 11	2023	$	[redacted]	Class 4	[redacted]	Miles
99	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 14	2023	$	[redacted]	Class 4	[redacted]	Miles
100	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 8	2023	$	[redacted]	Class 4	[redacted]	Miles
101	Age & Condition	Circuit Rebuilds	PARK FLETCHER NO. 3	2023	$	[redacted]	Class 4	[redacted]	Miles
102	Age & Condition	Circuit Rebuilds	PARK FLETCHER NO. 7	2023	$	[redacted]	Class 4	[redacted]	Miles
103	Age & Condition	Circuit Rebuilds	PARKER NO. 1	2023	$	[redacted]	Class 4	[redacted]	Miles
104	Age & Condition	Circuit Rebuilds	PIKE NO. 6	2023	$	[redacted]	Class 4	[redacted]	Miles
105	Age & Condition	Circuit Rebuilds	POST RD NO. 5	2023	$	[redacted]	Class 4	[redacted]	Miles
106	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 3	2023	$	[redacted]	Class 4	[redacted]	Miles
107	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 6	2023	$	[redacted]	Class 4	[redacted]	Miles
108	Age & Condition	Circuit Rebuilds	SHEFFIELD NO. 1	2023	$	[redacted]	Class 4	[redacted]	Miles
109	Age & Condition	Circuit Rebuilds	SOUTH NO. 7	2023	$	[redacted]	Class 4	[redacted]	Miles
110	Age & Condition	Circuit Rebuilds	SOUTH NO. 8	2023	$	[redacted]	Class 4	[redacted]	Miles
111	Age & Condition	Circuit Rebuilds	SOUTHEAST NO. 5	2023	$	[redacted]	Class 4	[redacted]	Miles
112	Age & Condition	Circuit Rebuilds	SOUTHPORT NO. 1	2023	$	[redacted]	Class 4	[redacted]	Miles
113	Age & Condition	Circuit Rebuilds	SOUTHPORT NO. 3	2023	$	[redacted]	Class 4	[redacted]	Miles
114	Age & Condition	Circuit Rebuilds	SOUTHPORT NO. 7	2023	$	[redacted]	Class 4	[redacted]	Miles
115	Age & Condition	Circuit Rebuilds	THOMPSON NO. 6	2023	$	[redacted]	Class 4	[redacted]	Miles
116	Age & Condition	Circuit Rebuilds	TOBEY NO. 1	2023	$	[redacted]	Class 4	[redacted]	Miles
117	Age & Condition	Circuit Rebuilds	TREMONT NO. 3	2023	$	[redacted]	Class 4	[redacted]	Miles
118	Age & Condition	Circuit Rebuilds	TREMONT NO. 5	2023	$	[redacted]	Class 4	[redacted]	Miles
119	Age & Condition	Circuit Rebuilds	WEST NO. 4	2023	$	[redacted]	Class 4	[redacted]	Miles
120	Age & Condition	Circuit Rebuilds	WEST NO. 8	2023	$	[redacted]	Class 4	[redacted]	Miles

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
121	Age & Condition	Circuit Rebuilds	WESTLANE NO. 3	2023	$ [redacted]	Class 4	[redacted]	Miles
		Circuit Rebuilds Total			$ 52,812,143		[redacted]	
249	Age & Condition	Substation Assets Replacements	GUION	2023	$ [redacted]	Class 4	[redacted]	Units
250	Age & Condition	Substation Assets Replacements	LAWRENCE	2023	$ [redacted]	Class 4	[redacted]	Units
251	Age & Condition	Substation Assets Replacements	PARKER	2023	$ [redacted]	Class 4	[redacted]	Units
252	Age & Condition	Substation Assets Replacements	SOUTHPORT	2023	$ [redacted]	Class 4	[redacted]	Units
253	Age & Condition	Substation Assets Replacements	SUNNYSIDE	2023	$ [redacted]	Class 4	[redacted]	Units
254	Age & Condition	Substation Assets Replacements	WEST	2023	$ [redacted]	Class 4	[redacted]	Units
		Substation Assets Replacements Total			$ 39,220,541		[redacted]	
275	Age & Condition	XLPE Cable Replacement	**XLPE Cable Replacements - 2023**	2023	$ [redacted]	Class 4	[redacted]	Feet
		XLPE Cable Replacement Total			$ 12,354,210		[redacted]	
296	Age & Condition	4 kV Conversion	CONVERT HEMLOCK TIE	2023	$ [redacted]	Class 4	[redacted]	Units
297	Age & Condition	4 kV Conversion	CONVERT COLUMBIA	2023	$ [redacted]	Class 4	[redacted]	Units
298	Age & Condition	4 kV Conversion	CONVERT McPHERSON TIE	2023	$ [redacted]	Class 4	[redacted]	Units
299	Age & Condition	4 kV Conversion	CONVERT RUCKLE TIE	2023	$ [redacted]	Class 4	[redacted]	Units
300	Age & Condition	4 kV Conversion	CONVERT COLLEGE	2023	$ [redacted]	Class 4	[redacted]	Units
301	Age & Condition	4 kV Conversion	CONVERT WATSON	2023	$ [redacted]	Class 4	[redacted]	Units
302	Age & Condition	4 kV Conversion	CONVERT 36th ST TIE	2023	$ [redacted]	Class 4	[redacted]	Units
		4 kV Conversion Total			$ 15,541,783		[redacted]	
346	Age & Condition	Tap Reliability Improvement Projects	TRIP - 2023	2023	$ [redacted]	Class 4	[redacted]	Units
		Tap Reliability Improvement Projects Total			$ 10,824,322		[redacted]	
353	Age & Condition	Meter Replacement	Meter Replacement - 2023	2023	$ [redacted]	Class 4	[redacted]	Meters
		Meter Replacement Total			$ 11,392,783		[redacted]	
410	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M54-01	2023	$ [redacted]	Class 4	[redacted]	Units
411	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M54-02	2023	$ [redacted]	Class 4	[redacted]	Units
412	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M45-02	2023	$ [redacted]	Class 4	[redacted]	Units
413	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M45-99	2023	$ [redacted]	Class 4	[redacted]	Units
414	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M45-03	2023	$ [redacted]	Class 4	[redacted]	Units
415	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M54-97	2023	$ [redacted]	Class 4	[redacted]	Units
416	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M55-08	2023	$ [redacted]	Class 4	[redacted]	Units
417	Age & Condition	CBD Secondary Network Upgrades	Duct Line (300 ft.) Location (vic. Michigan St. and Mass. Ave.)	2023	$ [redacted]	Class 4	[redacted]	Units
418	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 108 E. Maryland, UG412	2023	$ [redacted]	Class 4	[redacted]	Units
419	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 215 W. New York, UG411	2023	$ [redacted]	Class 4	[redacted]	Units
420	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 535 Mass. Ave., UG422	2023	$ [redacted]	Class 4	[redacted]	Units
421	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG432 227 E. Market	2023	$ [redacted]	Class 4	[redacted]	Units
422	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG412 108 E. Maryland	2023	$ [redacted]	Class 4	[redacted]	Units
423	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG411 215 W. New York	2023	$ [redacted]	Class 4	[redacted]	Units
424	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG442 2 W. Washington	2023	$ [redacted]	Class 4	[redacted]	Units
425	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG432 126 E. Market	2023	$ [redacted]	Class 4	[redacted]	Units

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
426	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG611 301 W. Maryland	2023	$ [redacted]	Class 4	[redacted]	Units
427	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 686 ft) MH M54-00 to MH M54-02	2023	$ [redacted]	Class 4	[redacted]	Units
428	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 828 ft) MH M54-00 to MH M54-03	2023	$ [redacted]	Class 4	[redacted]	Units
429	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 914 ft) MH M45-03 to MH M45-99	2023	$ [redacted]	Class 4	[redacted]	Units
430	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cicuit 641 (Length 1,988 ft)	2023	$ [redacted]	Class 4	[redacted]	Units
431	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Edison Circuit 463 (Length 4,023 ft)	2023	$ [redacted]	Class 4	[redacted]	Units
432	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable with Manholes (1307 ft.) MH in Year	2023	$ [redacted]	Class 4	[redacted]	Units
433	Age & Condition	CBD Secondary Network Upgrades	Real Time DTS Monitoring (vic. Indiana Ave. network Quadrant)	2023	$ [redacted]	Class 4	[redacted]	Units
434	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 321 W. New York, 215 W. New York	2023	$ [redacted]	Class 4	[redacted]	Units
435	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 229 W. Michigan, 210 W. North	2023	$ [redacted]	Class 4	[redacted]	Units
436	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 212 W. Michigan, 139 W. Vermont, 143 N. Illinois	2023	$ [redacted]	Class 4	[redacted]	Units
437	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 651 N. Pierson, 427 N. Illinois, 315 N. Pierson	2023	$ [redacted]	Class 4	[redacted]	Units
		CBD Secondary Network Upgrades Total			$ 5,868,219		[redacted]	
522	Age & Condition	Static Wire Performance Improvement	132-46 Sunnyside - Geist	2023	$ [redacted]	Class 4	[redacted]	Miles
523	Age & Condition	Static Wire Performance Improvement	132-51 German Church - Cumberland	2023	$ [redacted]	Class 4	[redacted]	Miles
524	Age & Condition	Static Wire Performance Improvement	132-43 Gulon - Crestview	2023	$ [redacted]	Class 4	[redacted]	Miles
		Static Wire Performance Improvement Total			$ 11,200,958		[redacted]	
558	Age & Condition	Remote End - Breaker Relay/Upgrades	METHODIST HOSPITAL-3131-1 BKR - Relay	2023	$ [redacted]	Class 4	[redacted]	Units
559	Age & Condition	Remote End - Breaker Relay/Upgrades	ALLISON #3-451-1 BREAKER - Breaker	2023	$ [redacted]	Class 4	[redacted]	Units
560	Age & Condition	Remote End - Breaker Relay/Upgrades	SUNNYSIDE-132-46 BKR - Breaker	2023	$ [redacted]	Class 4	[redacted]	Units
		Remote End - Breaker Relay/Upgrades Total			$ 1,608,007		[redacted]	
596	Age & Condition	Pole Replacements	Pole Replacement - 2023	2023	$ [redacted]	Class 4	[redacted]	Poles
597	Age & Condition	Pole Replacements	Pole Treatment - 2023	2023	$ [redacted]	Class 4	[redacted]	Poles
		Pole Replacements Total			$ 3,455,435		[redacted]	
607	Age & Condition	Steel Tower Life Extension	Steel Tower Life Extension - 2023	2023	$ [redacted]	Class 4	[redacted]	Structures
		Steel Tower Life Extension Total			$ 850,752		[redacted]	
611	Deliverability	Distribution Automation	Reclosers - 2023	2023	$ [redacted]	Class 4	[redacted]	Reclosers
		Distribution Automation Total			$ 13,916,985		[redacted]	
622	Deliverability	Substation Design Upgrades	Guion - 345/138kv Auto Xfmr Ring Bus	2023	$ [redacted]	Class 4	[redacted]	Units
623	Deliverability	Substation Design Upgrades	New Retail Substation	2023	$ [redacted]	Class 4	[redacted]	Units
624	Deliverability	Substation Design Upgrades	Northwest Control House	2023	$ [redacted]	Class 4	[redacted]	Units
		Substation Design Upgrades Total			$ 32,905,072		[redacted]	
		Grand Total			$ 211,971,249			

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
122	Age & Condition	Circuit Rebuilds	CENTER NO. 9	2024	$ [redacted]	Class 4	[redacted]	Miles
123	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 2	2024	$ [redacted]	Class 4	[redacted]	Miles
124	Age & Condition	Circuit Rebuilds	CUMBERLAND NO. 2	2024	$ [redacted]	Class 4	[redacted]	Miles
125	Age & Condition	Circuit Rebuilds	CUMBERLAND NO. 6	2024	$ [redacted]	Class 4	[redacted]	Miles
126	Age & Condition	Circuit Rebuilds	EAST NO. 9	2024	$ [redacted]	Class 4	[redacted]	Miles
127	Age & Condition	Circuit Rebuilds	GEIST NO. 4	2024	$ [redacted]	Class 4	[redacted]	Miles
128	Age & Condition	Circuit Rebuilds	GERMAN CHURCH NO. 8	2024	$ [redacted]	Class 4	[redacted]	Miles
129	Age & Condition	Circuit Rebuilds	NORTH NO. 3	2024	$ [redacted]	Class 4	[redacted]	Miles
130	Age & Condition	Circuit Rebuilds	PARK FLETCHER NO. 1	2024	$ [redacted]	Class 4	[redacted]	Miles
131	Age & Condition	Circuit Rebuilds	PARK FLETCHER NO. 2	2024	$ [redacted]	Class 4	[redacted]	Miles
132	Age & Condition	Circuit Rebuilds	PARK FLETCHER NO. 6	2024	$ [redacted]	Class 4	[redacted]	Miles
133	Age & Condition	Circuit Rebuilds	PARKER NO. 7	2024	$ [redacted]	Class 4	[redacted]	Miles
134	Age & Condition	Circuit Rebuilds	PROSPECT NO. 1	2024	$ [redacted]	Class 4	[redacted]	Miles
135	Age & Condition	Circuit Rebuilds	QUEMETCO NO. 2	2024	$ [redacted]	Class 4	[redacted]	Miles
136	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 5	2024	$ [redacted]	Class 4	[redacted]	Miles
137	Age & Condition	Circuit Rebuilds	SHEFFIELD NO. 9	2024	$ [redacted]	Class 4	[redacted]	Miles
138	Age & Condition	Circuit Rebuilds	SHEFFIELD NO. 10	2024	$ [redacted]	Class 4	[redacted]	Miles
139	Age & Condition	Circuit Rebuilds	SOUTH NO. 3	2024	$ [redacted]	Class 4	[redacted]	Miles
140	Age & Condition	Circuit Rebuilds	SOUTHEAST NO. 1	2024	$ [redacted]	Class 4	[redacted]	Miles
141	Age & Condition	Circuit Rebuilds	SOUTHEAST NO. 7	2024	$ [redacted]	Class 4	[redacted]	Miles
142	Age & Condition	Circuit Rebuilds	SOUTHPORT NO. 2	2024	$ [redacted]	Class 4	[redacted]	Miles
143	Age & Condition	Circuit Rebuilds	SOUTHPORT NO. 4	2024	$ [redacted]	Class 4	[redacted]	Miles
144	Age & Condition	Circuit Rebuilds	SOUTHPORT NO. 8	2024	$ [redacted]	Class 4	[redacted]	Miles
145	Age & Condition	Circuit Rebuilds	SOUTHWEST NO. 3	2024	$ [redacted]	Class 4	[redacted]	Miles
146	Age & Condition	Circuit Rebuilds	TOBEY NO. 6	2024	$ [redacted]	Class 4	[redacted]	Miles
147	Age & Condition	Circuit Rebuilds	WESTLANE NO. 4	2024	$ [redacted]	Class 4	[redacted]	Miles
148	Age & Condition	Circuit Rebuilds	WILLIAMS NO. 1	2024	$ [redacted]	Class 4	[redacted]	Miles
149	Age & Condition	Circuit Rebuilds	WILLIAMS NO. 4	2024	$ [redacted]	Class 4	[redacted]	Miles
		Circuit Rebuilds Total			$ 47,773,667			
255	Age & Condition	Substation Assets Replacements	ALLISON #3	2024	$ [redacted]	Class 4	[redacted]	Units
256	Age & Condition	Substation Assets Replacements	MAYWOOD	2024	$ [redacted]	Class 4	[redacted]	Units
257	Age & Condition	Substation Assets Replacements	MILL STREET	2024	$ [redacted]	Class 4	[redacted]	Units
258	Age & Condition	Substation Assets Replacements	SOUTHWEST	2024	$ [redacted]	Class 4	[redacted]	Units
		Substation Assets Replacements Total			$ 34,451,705			
276	Age & Condition	XLPE Cable Replacement	XLPE Cable Replacements - 2024	2024	$ [redacted]	Class 4	[redacted]	Feet
		XLPE Cable Replacement Total			$ 12,297,234			
303	Age & Condition	4 kV Conversion	CONVERT 32nd ST TIE	2024	$ [redacted]	Class 4	[redacted]	Units
304	Age & Condition	4 kV Conversion	CONVERT CROWN HILL	2024	$ [redacted]	Class 4	[redacted]	Units
305	Age & Condition	4 kV Conversion	CONVERT SALEM	2024	$ [redacted]	Class 4	[redacted]	Units

Indianapolis Power & Light Company
2024 - TDSIC Project Detail - Capital Dollars Only

	(A)	(B)	(C)	(D)	(E)		(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year		Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
305	Age & Condition	4 kV Conversion	CONVERT SUMMIT	2024	$	[redacted]	Class 4	[redacted]	Units
307	Age & Condition	4 kV Conversion	CONVERT 33rd ST TIE	2024	$	[redacted]	Class 4	[redacted]	Units
308	Age & Condition	4 kV Conversion	CONVERT COOP	2024	$	[redacted]	Class 4	[redacted]	Units
309	Age & Condition	4 kV Conversion	CONVERT TRENTON	2024	$	[redacted]	Class 4	[redacted]	Units
310	Age & Condition	4 kV Conversion	CONVERT ETHYL	2024	$	[redacted]	Class 4	[redacted]	Units
311	Age & Condition	4 kV Conversion	CONVERT TALBOTT	2024	$	[redacted]	Class 4	[redacted]	Units
		4 kV Conversion Total			$	7,583,329			
347	Age & Condition	Tap Reliability Improvement Projects	TRIP - 2024	2024	$	[redacted]	Class 4	[redacted]	Units
		Tap Reliability Improvement Projects Total			$	11,040,808			
354	Age & Condition	Meter Replacement	Meter Replacement - 2024	2024	$	[redacted]	Class 4	[redacted]	Meters
		Meter Replacement Total			$	11,620,639			
438	Age & Condition	CBD Secondary Network Upgrades	New Pre-Cast Manhole (Location vic. Michigan and Pennsylvania)	2024	$	[redacted]	Class 4	[redacted]	Units
439	Age & Condition	CBD Secondary Network Upgrades	New Pre-Cast Manhole (Location vic. 420 N. Pennsylvania)	2024	$	[redacted]	Class 4	[redacted]	Units
440	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH I35-03	2024	$	[redacted]	Class 4	[redacted]	Units
441	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M34-08	2024	$	[redacted]	Class 4	[redacted]	Units
442	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M34-09	2024	$	[redacted]	Class 4	[redacted]	Units
443	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M44-19	2024	$	[redacted]	Class 4	[redacted]	Units
444	Age & Condition	CBD Secondary Network Upgrades	Duct Line WR1 (200 ft.) (vic. Alabama and Mass. Ave.)	2024	$	[redacted]	Class 4	[redacted]	Units
445	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 326 E. New York, UG442	2024	$	[redacted]	Class 4	[redacted]	Units
446	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 117 E. Michigan, UG431	2024	$	[redacted]	Class 4	[redacted]	Units
447	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 150 E. Market, UG442	2024	$	[redacted]	Class 4	[redacted]	Units
448	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG652 120 W. Washington	2024	$	[redacted]	Class 4	[redacted]	Units
449	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG442 326 E. New York	2024	$	[redacted]	Class 4	[redacted]	Units
450	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG411 119 E. Vermont	2024	$	[redacted]	Class 4	[redacted]	Units
451	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG422 227 E. Market	2024	$	[redacted]	Class 4	[redacted]	Units
452	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG442 10 N. Meridian	2024	$	[redacted]	Class 4	[redacted]	Units
453	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG442 121 Monument Circle	2024	$	[redacted]	Class 4	[redacted]	Units
454	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 153 ft) MH M34-08 to MH M44-13	2024	$	[redacted]	Class 4	[redacted]	Units
455	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 97 ft) MH M34-09 to MH M34-08	2024	$	[redacted]	Class 4	[redacted]	Units
456	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 216 ft) MH M34-08 to MH M44-18	2024	$	[redacted]	Class 4	[redacted]	Units
457	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cicuit 642 (Length 1116 ft)	2024	$	[redacted]	Class 4	[redacted]	Units
458	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cicuit 641 (Length 3357 ft)	2024	$	[redacted]	Class 4	[redacted]	Units
459	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable with Manholes (300 ft.) MH in Year	2024	$	[redacted]	Class 4	[redacted]	Units
460	Age & Condition	CBD Secondary Network Upgrades	Real Time DAS Monitoring (Gardner Ln. north Quadrant)	2024	$	[redacted]	Class 4	[redacted]	Units
461	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 28 W. Michigan, 602 N. Alabama	2024	$	[redacted]	Class 4	[redacted]	Units
462	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 529 N. Ogden, 535 N. New Jersey	2024	$	[redacted]	Class 4	[redacted]	Units
463	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 535 Mass. Ave., 428 Mass. Ave., 390 Mass. Ave.	2024	$	[redacted]	Class 4	[redacted]	Units
464	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 333 Mass. Ave., 326 E. New York, 425 E. Vermont	2024	$	[redacted]	Class 4	[redacted]	Units
		CBD Secondary Network Upgrades Total			$	5,001,613			

Indianapolis Power & Light Company
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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
525	Age & Condition	Static Wire Performance Improvement	132-57 North - River Road	2024	$ [redacted]	Class 4	[redacted]	Miles
526	Age & Condition	Static Wire Performance Improvement	132-55 Castleton - River Road	2024	$ [redacted]	Class 4	[redacted]	Miles
527	Age & Condition	Static Wire Performance Improvement	132-52 Cumberland - Ford	2024	$ [redacted]	Class 4	[redacted]	Miles
528	Age & Condition	Static Wire Performance Improvement	132-50 German Church - Sunnyside	2024	$ [redacted]	Class 4	[redacted]	Miles
		Static Wire Performance Improvement Total			$ 11,497,320		[redacted]	
561	Age & Condition	Remote End - Breaker Relay/Upgrades	NORTH-132-71-86 TIE BKR (7) - Relay	2024	$ [redacted]	Class 4	[redacted]	Units
562	Age & Condition	Remote End - Breaker Relay/Upgrades	CRESTVIEW-138KV BUS TIE BKR - Relay	2024	$ [redacted]	Class 4	[redacted]	Units
563	Age & Condition	Remote End - Breaker Relay/Upgrades	SANITATION BLMT-138 BUSTIE OCB - Relay	2024	$ [redacted]	Class 4	[redacted]	Units
564	Age & Condition	Remote End - Breaker Relay/Upgrades	CASTLETON-132-66 BKR - Relay	2024	$ [redacted]	Class 4	[redacted]	Units
565	Age & Condition	Remote End - Breaker Relay/Upgrades	LAWRENCE-132-45 BREAKER - Relay	2024	$ [redacted]	Class 4	[redacted]	Units
566	Age & Condition	Remote End - Breaker Relay/Upgrades	ST GT YD-132-02 BKR - Relay	2024	$ [redacted]	Class 4	[redacted]	Units
567	Age & Condition	Remote End - Breaker Relay/Upgrades	IU CAMPUS N-437-1 BKR - Relay	2024	$ [redacted]	Class 4	[redacted]	Units
568	Age & Condition	Remote End - Breaker Relay/Upgrades	PERRY K-34.5KV 2839-1 BKR - Relay	2024	$ [redacted]	Class 4	[redacted]	Units
569	Age & Condition	Remote End - Breaker Relay/Upgrades	IU CAMPUS W-391-1 BKR - Relay	2024	$ [redacted]	Class 4	[redacted]	Units
570	Age & Condition	Remote End - Breaker Relay/Upgrades	BROOKWOOD-1571-5 BKR - Breaker & Relay	2024	$ [redacted]	Class 4	[redacted]	Units
571	Age & Condition	Remote End - Breaker Relay/Upgrades	BROOKWOOD-132-36 BKR - Breaker	2024	$ [redacted]	Class 4	[redacted]	Units
572	Age & Condition	Remote End - Breaker Relay/Upgrades	NORTHWEST-132-04 BKR - Breaker & Relay	2024	$ [redacted]	Class 4	[redacted]	Units
573	Age & Condition	Remote End - Breaker Relay/Upgrades	NORTHWEST-132-39 BKR - Breaker & Relay	2024	$ [redacted]	Class 4	[redacted]	Units
		Remote End - Breaker Relay/Upgrades Total			$ 6,334,867		[redacted]	
598	Age & Condition	Pole Replacements	Pole Replacement - 2024	2024	$ [redacted]	Class 4	[redacted]	Poles
599	Age & Condition	Pole Replacements	Pole Treatment - 2024	2024	$ [redacted]	Class 4	[redacted]	Poles
		Pole Replacements Total			$ 3,524,544		[redacted]	
612	Deliverability	Distribution Automation	Reclosers - 2024	2024	$ [redacted]	Class 4	[redacted]	Reclosers
		Distribution Automation Total			$ 14,195,325		[redacted]	
625	Deliverability	Substation Design Upgrades	Stout Sub - Add Breaker & Create Ring Bus	2024	$ [redacted]	Class 4	[redacted]	Units
626	Deliverability	Substation Design Upgrades	Southwest Control House	2024	$ [redacted]	Class 4	[redacted]	Units
		Substation Design Upgrades Total			$ 6,323,236			
		Grand Total			$ 171,544,287			

Indianapolis Power & Light Company
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Line No.	(A) Age & Condition or Deliverability	(B) Project Type	(C) project	(D) Year	(E) Plan Project Cost (Capital Dollars)	(F) AACE Cost Estimate	(G) Quantity	(H) Units
150	Age & Condition	Circuit Rebuilds	BROOKWOOD NO. 6	2025	$ [redacted]	Class 4	[redacted]	Miles
151	Age & Condition	Circuit Rebuilds	BROOKWOOD NO. 8	2025	$	Class 4		Miles
152	Age & Condition	Circuit Rebuilds	CASTLETON NO. 9	2025	$	Class 4		Miles
153	Age & Condition	Circuit Rebuilds	CENTER NO. 5	2025	$	Class 4		Miles
154	Age & Condition	Circuit Rebuilds	CRAWFORDSVILLE NO. 1	2025	$	Class 4		Miles
155	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 5	2025	$	Class 4		Miles
156	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 7	2025	$	Class 4		Miles
157	Age & Condition	Circuit Rebuilds	EAST NO. 2	2025	$	Class 4		Miles
158	Age & Condition	Circuit Rebuilds	GERMAN CHURCH NO. 5	2025	$	Class 4		Miles
159	Age & Condition	Circuit Rebuilds	GLENNS VALLEY NO. 8	2025	$	Class 4		Miles
160	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 7	2025	$	Class 4		Miles
161	Age & Condition	Circuit Rebuilds	MILL ST. NO. 6	2025	$	Class 4		Miles
162	Age & Condition	Circuit Rebuilds	MILL ST. NO. 10	2025	$	Class 4		Miles
163	Age & Condition	Circuit Rebuilds	PROSPECT NO. 3	2025	$	Class 4		Miles
164	Age & Condition	Circuit Rebuilds	SHEFFIELD NO. 8	2025	$	Class 4		Miles
165	Age & Condition	Circuit Rebuilds	SOUTH NO. 1	2025	$	Class 4		Miles
166	Age & Condition	Circuit Rebuilds	SOUTHEAST NO. 10	2025	$	Class 4		Miles
167	Age & Condition	Circuit Rebuilds	TOBEY NO. 3	2025	$	Class 4		Miles
168	Age & Condition	Circuit Rebuilds	WEST NO. 5	2025	$	Class 4		Miles
169	Age & Condition	Circuit Rebuilds	WESTLANE NO. 2	2025	$	Class 4		Miles
170	Age & Condition	Circuit Rebuilds	WESTLANE NO. 9	2025	$	Class 4		Miles
171	Age & Condition	Circuit Rebuilds	WILLIAMS NO. 6	2025	$	Class 4		Miles
		Circuit Rebuilds Total			$ 49,882,752			
259	Age & Condition	Substation Assets Replacements	EAST	2025	$ [redacted]	Class 4		Units
260	Age & Condition	Substation Assets Replacements	NAVAL AVIONICS	2025	$	Class 4		Units
261	Age & Condition	Substation Assets Replacements	NORTHWEST	2025	$	Class 4		Units
262	Age & Condition	Substation Assets Replacements	SOUTH	2025	$	Class 4		Units
263	Age & Condition	Substation Assets Replacements	SOUTHEAST	2025	$	Class 4		Units
		Substation Assets Replacements Total			$ 44,283,282			
277	Age & Condition	XLPE Cable Replacement	**XLPE Cable Replacements - 2025**	2025	$ [redacted]	Class 4		Feet
		XLPE Cable Replacement Total			$ 12,829,535			
312	Age & Condition	4 kV Conversion	CONVERT BECKWITH	2025	$ [redacted]	Class 4		Units
313	Age & Condition	4 kV Conversion	CONVERT CORNELL	2025	$	Class 4		Units
314	Age & Condition	4 kV Conversion	CONVERT ALVORD	2025	$	Class 4		Units
315	Age & Condition	4 kV Conversion	CONVERT INDUSTRIAL CENTER	2025	$	Class 4		Units
316	Age & Condition	4 kV Conversion	CONVERT MANLOVE	2025	$	Class 4		Units
317	Age & Condition	4 kV Conversion	CONVERT ROOSEVELT	2025	$	Class 4		Units
		4 kV Conversion Total			$ 12,385,359			
348	Age & Condition	Tap Reliability Improvement Projects	TRIP - 2025	2025	$ [redacted]	Class 4		Units

Indianapolis Power & Light Company
2025 - TDSIC Project Detail - Capital Dollars Only

	(A)	(B)	(C)	(D)		(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year		Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
		Tap Reliability Improvement Projects Total			$	11,261,624			
465	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M44-12	2025	$	[redacted]	Class 4	[redacted]	Units
466	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M44-10	2025	$	[redacted]	Class 4	[redacted]	Units
467	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M44-08	2025	$	[redacted]	Class 4	[redacted]	Units
468	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M44-07	2025	$	[redacted]	Class 4	[redacted]	Units
469	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M44-04	2025	$	[redacted]	Class 4	[redacted]	Units
470	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M44-98	2025	$	[redacted]	Class 4	[redacted]	Units
471	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M55-98	2025	$	[redacted]	Class 4	[redacted]	Units
472	Age & Condition	CBD Secondary Network Upgrades	Duct Line WR1 (200 ft.) (vic. New Jersey and Mass. Ave.)	2025	$	[redacted]	Class 4	[redacted]	Units
473	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 409 N. Pierson, UG441	2025	$	[redacted]	Class 4	[redacted]	Units
474	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 409 N. Pierson, UG451	2025	$	[redacted]	Class 4	[redacted]	Units
475	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 110 N. Scioto, UG422	2025	$	[redacted]	Class 4	[redacted]	Units
476	Age & Condition	CBD Secondary Network Upgrades	Rpl Network Transf. 120/208, UG651 60 W. Maryland	2025	$	[redacted]	Class 4	[redacted]	Units
477	Age & Condition	CBD Secondary Network Upgrades	Rpl Network Transf. 277/480, UG432 19 N. Meridian	2025	$	[redacted]	Class 4	[redacted]	Units
478	Age & Condition	CBD Secondary Network Upgrades	Rpl Network Transf 277/480, UG611 25 W. Georgia	2025	$	[redacted]	Class 4	[redacted]	Units
479	Age & Condition	CBD Secondary Network Upgrades	Rpl Network Transf. 277/480, UG641 21 S. Capital	2025	$	[redacted]	Class 4	[redacted]	Units
480	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cirut 633 (Length 4265 ft)	2025	$	[redacted]	Class 4	[redacted]	Units
481	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cirut 611 (Length 2535 ft)	2025	$	[redacted]	Class 4	[redacted]	Units
482	Age & Condition	CBD Secondary Network Upgrades	Real Time DAS Monitoring (Edison East Quadrant)	2025	$	[redacted]	Class 4	[redacted]	Units
483	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 115 E. Market, 117 N. Pennsylvania	2025	$	[redacted]	Class 4	[redacted]	Units
484	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 150 E. Market, 227 E. Market, 132 E. Washington	2025	$	[redacted]	Class 4	[redacted]	Units
485	Age & Condition	CBD Secondary Network Upgrades	Vault Technology 129 E. Washington, 21 Virginia Ave., 133 S. Delaware	2025	$	[redacted]	Class 4	[redacted]	Units
		CBD Secondary Network Upgrades Total			$	5,892,283			
529	Age & Condition	Static Wire Performance Improvement	132-38 Brookwood - Lawrence	2025	$	[redacted]	Class 4	[redacted]	Miles
530	Age & Condition	Static Wire Performance Improvement	132-49 East - Tobey	2025	$	[redacted]	Class 4	[redacted]	Miles
531	Age & Condition	Static Wire Performance Improvement	132-68 Tobey - German Church	2025	$	[redacted]	Class 4	[redacted]	Miles
532	Age & Condition	Static Wire Performance Improvement	132-33 Mill Street - Edison	2025	$	[redacted]	Class 4	[redacted]	Miles
		Static Wire Performance Improvement Total			$	10,679,473			
574	Age & Condition	Remote End - Breaker Relay/Upgrades	CRAWFORDSVILLE RD.-132-35 BKR - Relay	2025	$	[redacted]	Class 4	[redacted]	Units
575	Age & Condition	Remote End - Breaker Relay/Upgrades	WILLIAMS ST-132-75 BREAKER - Relay	2025	$	[redacted]	Class 4	[redacted]	Units
576	Age & Condition	Remote End - Breaker Relay/Upgrades	LILLY CORP-4151-3 BKR - Relay	2025	$	[redacted]	Class 4	[redacted]	Units
577	Age & Condition	Remote End - Breaker Relay/Upgrades	NAVAL AVIONICS-1771-1 - Breaker & Relay	2025	$	[redacted]	Class 4	[redacted]	Units
578	Age & Condition	Remote End - Breaker Relay/Upgrades	MAYWOOD-132-13 BREAKER - Breaker	2025	$	[redacted]	Class 4	[redacted]	Units
579	Age & Condition	Remote End - Breaker Relay/Upgrades	MAYWOOD-132-11 BREAKER - Breaker	2025	$	[redacted]	Class 4	[redacted]	Units
		Remote End - Breaker Relay/Upgrades Total			$	3,110,142			
600	Age & Condition	Pole Replacements	Pole Replacement - 2025	2025	$	[redacted]	Class 4	[redacted]	Poles
601	Age & Condition	Pole Replacements	Pole Treatment - 2025	2025	$	[redacted]	Class 4	[redacted]	Poles
		Pole Replacements Total			$	3,595,035			
613	Deliverability	Distribution Automation	Reclosers - 2025	2025	$	[redacted]	Class 4	[redacted]	Reclosers

Indianapolis Power & Light Company
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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
		Distribution Automation Total			$ 14,479,231			
627	Deliverability	Substation Design Upgrades	New Riverside Sub	2025	$ [redacted]	Class 4	[redacted]	Units
		Substation Design Upgrades Total			$ 16,777,568			
		Grand Total			$ 185,176,284			

Indianapolis Power & Light Company
2026 - TDSIC Project Detail - Capital Dollars Only

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
172	Age & Condition	Circuit Rebuilds	BROOKWOOD NO. 1	2026	$ [redacted]	Class 4	[redacted]	Miles
173	Age & Condition	Circuit Rebuilds	BROOKWOOD NO. 10	2026	$ [redacted]	Class 4	[redacted]	Miles
174	Age & Condition	Circuit Rebuilds	CAMBY NO. 3	2026	$ [redacted]	Class 4	[redacted]	Miles
175	Age & Condition	Circuit Rebuilds	CAMBY NO. 6	2026	$ [redacted]	Class 4	[redacted]	Miles
176	Age & Condition	Circuit Rebuilds	CENTER NO. 1	2026	$ [redacted]	Class 4	[redacted]	Miles
177	Age & Condition	Circuit Rebuilds	CENTER NO. 2	2026	$ [redacted]	Class 4	[redacted]	Miles
178	Age & Condition	Circuit Rebuilds	EDGEWOOD NO. 3	2026	$ [redacted]	Class 4	[redacted]	Miles
179	Age & Condition	Circuit Rebuilds	GUION NO. 8	2026	$ [redacted]	Class 4	[redacted]	Miles
180	Age & Condition	Circuit Rebuilds	INDIAN CREEK NO. 10	2026	$ [redacted]	Class 4	[redacted]	Miles
181	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 2	2026	$ [redacted]	Class 4	[redacted]	Miles
182	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 9	2026	$ [redacted]	Class 4	[redacted]	Miles
183	Age & Condition	Circuit Rebuilds	MILL ST. NO. 8	2026	$ [redacted]	Class 4	[redacted]	Miles
184	Age & Condition	Circuit Rebuilds	MOORESVILLE NO. 2	2026	$ [redacted]	Class 4	[redacted]	Miles
185	Age & Condition	Circuit Rebuilds	NORTH NO. 5	2026	$ [redacted]	Class 4	[redacted]	Miles
186	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 6	2026	$ [redacted]	Class 4	[redacted]	Miles
187	Age & Condition	Circuit Rebuilds	PARKER NO. 4	2026	$ [redacted]	Class 4	[redacted]	Miles
188	Age & Condition	Circuit Rebuilds	POST RD NO. 2	2026	$ [redacted]	Class 4	[redacted]	Miles
189	Age & Condition	Circuit Rebuilds	SOUTH NO. 2	2026	$ [redacted]	Class 4	[redacted]	Miles
190	Age & Condition	Circuit Rebuilds	SOUTH NO. 9	2026	$ [redacted]	Class 4	[redacted]	Miles
191	Age & Condition	Circuit Rebuilds	SOUTHEAST NO. 3	2026	$ [redacted]	Class 4	[redacted]	Miles
192	Age & Condition	Circuit Rebuilds	SOUTHEAST NO. 8	2026	$ [redacted]	Class 4	[redacted]	Miles
193	Age & Condition	Circuit Rebuilds	SOUTHWEST NO. 2	2026	$ [redacted]	Class 4	[redacted]	Miles
194	Age & Condition	Circuit Rebuilds	SOUTHWEST NO. 4	2026	$ [redacted]	Class 4	[redacted]	Miles
195	Age & Condition	Circuit Rebuilds	WEST NO. 6	2026	$ [redacted]	Class 4	[redacted]	Miles
196	Age & Condition	Circuit Rebuilds	WEST NO. 7	2026	$ [redacted]	Class 4	[redacted]	Miles
197	Age & Condition	Circuit Rebuilds	WESTLANE NO. 10	2026	$ [redacted]	Class 4	[redacted]	Miles
198	Age & Condition	Circuit Rebuilds	WILLIAMS NO. 7	2026	$ [redacted]	Class 4	[redacted]	Miles
		Circuit Rebuilds Total			$ 49,913,886		[redacted]	
264	Age & Condition	Substation Assets Replacements	BROOKWOOD	2026	$ [redacted]	Class 4	[redacted]	Units
265	Age & Condition	Substation Assets Replacements	ENGLISH	2026	$ [redacted]	Class 4	[redacted]	Units
266	Age & Condition	Substation Assets Replacements	EVANS MILLING INDUSTRIAL SUB	2026	$ [redacted]	Class 4	[redacted]	Units
267	Age & Condition	Substation Assets Replacements	GLIDDEN	2026	$ [redacted]	Class 4	[redacted]	Units
268	Age & Condition	Substation Assets Replacements	NATIONAL STARCH	2026	$ [redacted]	Class 4	[redacted]	Units
269	Age & Condition	Substation Assets Replacements	NORTH	2026	$ [redacted]	Class 4	[redacted]	Units
270	Age & Condition	Substation Assets Replacements	NORTHEAST	2026	$ [redacted]	Class 4	[redacted]	Units
271	Age & Condition	Substation Assets Replacements	PROSPECT	2026	$ [redacted]	Class 4	[redacted]	Units
		Substation Assets Replacements Total			$ 46,536,273		[redacted]	
278	Age & Condition	XLPE Cable Replacement	XLPE Cable Replacements - 2026	2026	$ [redacted]	Class 4	[redacted]	Feet
		XLPE Cable Replacement Total			$ 12,301,534		[redacted]	

Indianapolis Power & Light Company
2026 - TDSIC Project Detail - Capital Dollars Only

	(A)	(B)	(C)	(D)		(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year		Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
318	Age & Condition	4 kV Conversion	CONVERT JEFFERSON	2026	$	[redacted]	Class 4	[redacted]	Units
319	Age & Condition	4 kV Conversion	CONVERT LUDLOW	2026	$	[redacted]	Class 4	[redacted]	Units
320	Age & Condition	4 kV Conversion	CONVERT SUTHERLAND	2026	$	[redacted]	Class 4	[redacted]	Units
321	Age & Condition	4 kV Conversion	CONVERT BRIGHT	2026	$	[redacted]	Class 4	[redacted]	Units
322	Age & Condition	4 kV Conversion	CONVERT SCHWITZER NO 1	2026	$	[redacted]	Class 4	[redacted]	Units
323	Age & Condition	4 kV Conversion	CONVERT SCHWITZER NO 2	2026	$	[redacted]	Class 4	[redacted]	Units
		4 kV Conversion Total			$	7,520,673		[redacted]	
349	Age & Condition	Tap Reliability Improvement Projects	TRIP - 2026	2026	$	[redacted]	Class 4	[redacted]	Units
		Tap Reliability Improvement Projects Total			$	11,486,857		[redacted]	
486	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M32-14	2026	$	[redacted]	Class 4	[redacted]	Units
487	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M33-94	2026	$	[redacted]	Class 4	[redacted]	Units
488	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M33-95	2026	$	[redacted]	Class 4	[redacted]	Units
489	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M33-08	2026	$	[redacted]	Class 4	[redacted]	Units
490	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M33-06	2026	$	[redacted]	Class 4	[redacted]	Units
491	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M33-05	2026	$	[redacted]	Class 4	[redacted]	Units
492	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M23-93	2026	$	[redacted]	Class 4	[redacted]	Units
493	Age & Condition	CBD Secondary Network Upgrades	Duct Line (200 ft.) (vic. Delaware and Mass. Ave.)	2026	$	[redacted]	Class 4	[redacted]	Units
494	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 110 N. Scioto, UG432	2026	$	[redacted]	Class 4	[redacted]	Units
495	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 126 E. Market, UG432	2026	$	[redacted]	Class 4	[redacted]	Units
496	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 119 E. Vermont, UG411	2026	$	[redacted]	Class 4	[redacted]	Units
497	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG651 21 S. Capital	2026	$	[redacted]	Class 4	[redacted]	Units
498	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG432 30 E. Market	2026	$	[redacted]	Class 4	[redacted]	Units
499	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG633 40 N. Capital	2026	$	[redacted]	Class 4	[redacted]	Units
500	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG412 150 E. Ohio	2026	$	[redacted]	Class 4	[redacted]	Units
501	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG442 225 E. Michigan	2026	$	[redacted]	Class 4	[redacted]	Units
502	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG481 525 N. Pennsylvania	2026	$	[redacted]	Class 4	[redacted]	Units
503	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cicuit 613 (Length 3997 ft)	2026	$	[redacted]	Class 4	[redacted]	Units
504	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cicuit 622 (Length 2681 ft)	2026	$	[redacted]	Class 4	[redacted]	Units
505	Age & Condition	CBD Secondary Network Upgrades	Real Time DAS Monitoring (Edison West Quadrant)	2026	$	[redacted]	Class 4	[redacted]	Units
506	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 123 S. Illinois, 33 W. Georgia	2026	$	[redacted]	Class 4	[redacted]	Units
507	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 26 S. Meridian, 38 S. Meridian	2026	$	[redacted]	Class 4	[redacted]	Units
508	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 20 E. Maryland, 30 S. Pennsylvania	2026	$	[redacted]	Class 4	[redacted]	Units
509	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 30 E. Georgia, 31 E. Georgia, 211 S. Meridian	2026	$	[redacted]	Class 4	[redacted]	Units
		CBD Secondary Network Upgrades Total			$	6,373,447		[redacted]	
533	Age & Condition	Static Wire Performance Improvement	132-54 Castleton - Geist	2026	$	[redacted]	Class 4	[redacted]	Miles
534	Age & Condition	Static Wire Performance Improvement	132-64 Rockville - Allison #4	2026	$	[redacted]	Class 4	[redacted]	Miles
		Static Wire Performance Improvement Total			$	7,601,921		[redacted]	
580	Age & Condition	Remote End - Breaker Relay/Upgrades	SOUTHEAST-132-72 BKR - Relay	2026	$	[redacted]	Class 4	[redacted]	Units
581	Age & Condition	Remote End - Breaker Relay/Upgrades	SOUTHEAST-132-18 BKR - Relay	2026	$	[redacted]	Class 4	[redacted]	Units

Indianapolis Power & Light Company
2026 - TDSIC Project Detail - Capital Dollars Only

	(A)	(B)	(C)	(D)	(E)		(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)		AACE Cost Estimate	Quantity	Units
582	Age & Condition	Remote End - Breaker Relay/Upgrades	PROSPECT-1751-1 BREAKER - Breaker	2026	$	[redacted]	Class 4	[redacted]	Units
583	Age & Condition	Remote End - Breaker Relay/Upgrades	IU CAMPUS N-491-3 BKR - Relay	2026	$	[redacted]	Class 4	[redacted]	Units
584	Age & Condition	Remote End - Breaker Relay/Upgrades	IU CAMPUS W-431-3 BKR - Relay	2026	$	[redacted]	Class 4	[redacted]	Units
585	Age & Condition	Remote End - Breaker Relay/Upgrades	EAST-132-07 W BKR - Breaker	2026	$	[redacted]	Class 4	[redacted]	Units
586	Age & Condition	Remote End - Breaker Relay/Upgrades	WEST-132-70W BKR - Breaker	2026	$	[redacted]	Class 4	[redacted]	Units
587	Age & Condition	Remote End - Breaker Relay/Upgrades	WEST-132-05 BKR - Breaker & Relay	2026	$	[redacted]	Class 4	[redacted]	Units
588	Age & Condition	Remote End - Breaker Relay/Upgrades	WEST-132-63 BKR - Breaker	2026	$	[redacted]	Class 4	[redacted]	Units
589	Age & Condition	Remote End - Breaker Relay/Upgrades	EAST-132-07 E BKR - Breaker & Relay	2026	$	[redacted]	Class 4	[redacted]	Units
		Remote End - Breaker Relay/Upgrades Total			$	6,425,834		[redacted]	
602	Age & Condition	Pole Replacements	Pole Replacement - 2026	2026	$	[redacted]	Class 4	[redacted]	Poles
603	Age & Condition	Pole Replacements	Pole Treatment - 2026	2026	$	[redacted]	Class 4	[redacted]	Poles
		Pole Replacements Total			$	3,666,935		[redacted]	
614	Deliverability	Distribution Automation	Reclosers - 2026	2026	$	[redacted]	Class 4	[redacted]	Reclosers
		Distribution Automation Total			$	14,768,816		[redacted]	
628	Deliverability	Substation Design Upgrades	Northeast Control House	2026	$	[redacted]	Class 4	[redacted]	Units
		Substation Design Upgrades Total			$	2,632,615			
		Grand Total			$	169,228,791			

Public Appendix 8.8 Class 2 Estimate Example

Indianapolis Power & Light Company
PROJECT ESTIMATE SUPPLEMENT

PROJECT NAME:	Maywood No 1	Project #	
		WMIS #	517721

Section	MATERIAL DESCRIPTION	UOM	QTY	MATERIAL UNIT PRICE	MATERIAL TOTAL	
	CONTRACTOR MATERIAL & OR PURCHASED EQUIPMENT & MATERIAL					
	Use for contractor supplied material if applicable				0	
					0	
					0	
					0	
					0	
					0	
					0	
					0	
					0	
					0	
					0	
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					0	
					0	
					0	
					0	
					0	
					0	
					0	
	IPL STORES MATERIAL & EQUIP					
	Use for IPL supplied material. Input a single line item total since a WMS material request is already generated.		1	[redacted]		CON
	Transformers	LOT	1			CON
					0	
					0	
					0	
					0	
					0	
					0	
					0	
					0	

Section	CONTRACTOR NAME OR IPL DEPT.	LABOR INSTALLATION COSTS HOURS	RATE	TOTAL	
	CONTRACTOR LABOR				
	Construct labor hours from WMS for overhead labor, include street light labor. $[redacted]per hour includes labor and equipment	1,629.82	[redacted]		CON
	Traffic control crew hours. Construct hours / 5 * $[redacted]	365.96	[redacted]		CON
	Hydrovac - pole count *$[redacted]	37.00	[redacted]		CON
	Hydrovac Misc - add additonal based on job specifics (rate is $[redacted]per hour)	5.00	[redacted]		CON
	Line Clearing - Total cost / [redacted]to get crew hours (crew rate = $[redacted]	534.44	[redacted]		CON
	Engineering design and calc. Hours * $[redacted] Hours to complete IFC + 20%	172.00	[redacted]		CON
	SWPP plan development (flat rate)	1.00	[redacted]		CON
	SWPP management (estimate provided) Total / $[redacted]to get hours	100.00	[redacted]		CON
	Ingress / R/W clearing (total /$[redacted]to get hours)	43.33	[redacted]		CON
	R/W restoration (estimate provided) Total / $[redacted]to get hours. Includes contractor provided material. (backfill dirt)	23.33	[redacted]		CON
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
	IPL LABOR				
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
	IPL LABOR (ENGINEER & SUPERVISION)				
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	

TOTAL CONSTRUCTION COSTS		
IPL Stores Equip. Material	Use for Cash Flow Wks	[redacted]
Contractor Svcs. Material	Use for Cash Flow Wks	
Contractor Svcs. Labor	Use for Cash Flow Wks	
IPL Labor-Hourly ($)	Use for Cash Flow Wks	
IPL Labor-Salaried ($)	Use for Cash Flow Wks	
Sales Tax	Calc from Cash Flow Wks	
Indirects	Calc from Cash Flow Wks	
AFUDC	Calc from Cash Flow Wks	
CONSTRUCTION TOTAL		
CIAC	Calc from Cash Flow Wks	
NET CAPITAL	Calc from Cash Flow Wks	

TOTAL REMOVAL/SALVAGE COSTS		
Contractor Svcs. Material	Use for Cash Flow Wks	$0
Contractor Svcs. Labor	Use for Cash Flow Wks	$0
IPL Labor-Hourly ($)	Use for Cash Flow Wks	$0
IPL Labor-Salaried ($)	Use for Cash Flow Wks	$0
Indirects	Calc from Cash Flow Wks	$0
RETIREMENT TOTAL		$0
SALVAGE/PROCEEDS	Calc from Cash Flow Wks	$0

IPL - An AES Company

ESTIMATE DETAIL SUMMARY Project # | WMIS 517721

PROJECT NAME: Maywood No 1

AFUDC Eligible (Y or N): Y

Must be a Capital project, must have a duration of > 30 days, must cost >$1,000

CIAC or Full Bill Projects are Not Eligible for AFUDC

Year 1 — 2019	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CONSTRUCTION COSTS													
IPL Stores Equip. Material					[redacted]								[redacted]
Contractor Svcs. Material													0
Contractor Svcs. Labor					[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
Trans/Dist Lines Physical													0
PD Other Labor													0
Trans Design/Troublemen													0
Sub/Network/Relay-SCADA													0
Sales Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Indirects - A&G, Stores	0	0	0	0	[redacted]	0	0	0	0	0	0	0	[redacted]
AFUDC Debt	0	0	0	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0	0	[redacted]
AFUDC Equity	0	0	0	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0	0	[redacted]
CONSTRUCTION TOTAL	0	0	0	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0	0	[redacted]
CIAC / Full Cost Bill													0
RETIREMENT COSTS													
Contractor Svcs. Labor					0	0	0	0	0	0			0
Trans/Dist Lines Physical													0
PD Other													0
Trans Design/Troublemen													0
Sub/Network/Relay-SCADA													0
Indirects - A&G, Stores	0	0	0	0	0	0	0	0	0	0	0	0	0
RETIREMENT TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0
SALVAGE/PROCEEDS													0
NET CAPITAL COSTS	0	0	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	0	[illegible]

Year 2 — 2020	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CONSTRUCTION COSTS													
IPL Stores Equip. Material													0
Contractor Svcs. Material													0
Contractor Svcs. Labor													0
Trans/Dist Lines Physical													0
PD Other Labor													0
Trans Design/Troublemen													0
Sub/Network/Relay-SCADA													0
Sales Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Indirects - A&G, Stores	0	0	0	0	0	0	0	0	0	0	0	0	0
AFUDC Debt	0	0	0	0	0	0	0	0	0	0	0	0	0
AFUDC Equity	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSTRUCTION TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0
CIAC / Full Cost Bill													0
RETIREMENT COSTS													
Contractor Svcs. Labor													0
Trans/Dist Lines Physical													0
PD Other													0
Trans Design/Troublemen													0
Sub/Network/Relay-SCADA													0
Indirects - A&G, Stores	0	0	0	0	0	0	0	0	0	0	0	0	0
RETIREMENT TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0
SALVAGE/PROCEEDS													0
NET CAPITAL COSTS	0	0	0	0	0	0	0	0	0	0	0	0	0

Expected Annual Cash Outflow	2019	2020
Cash Outflow	[redacted]	0
Miss per Cash Flow	0	

Total $ per Construct Cash Flow Estimate: [redacted]

Total $ per Retire Cash Flow Estimate: 0

TOTAL AFUDC: [redacted]
CONSTRUCTION INDIRECTS: [redacted]
RETIREMENT INDIRECTS: [redacted]

Description	Rate	Eff. Date	
Trans/Dist Lines Physical	[redacted]	04/01/15	CC 105
Sub/Network/Relay-SCADA		04/01/18	CC's 103, 124, 129
AFUDC Debt		03/31/19	
AFUDC Equity		03/31/19	
IPL Stores Material Handling		01/01/19	
Benefits & FICA tax		04/01/18	
Travel Time Lines			

	Description	Rate	Eff. Date	
H	Trans Design/Troublemen	[redacted]	04/01/15	CC's 121, 123
I	PD Other		04/01/18	All Other PD CC's
J	Trans Contractor Labor		11/1/2013	Currently No Contractor Indirects
K	Sales Tax		4/1/2002	

Maywood No 1

TDSIC Elegible Cost Estimate		
	Material	$[redacted]
	Construction Contract Labor	$[redacted]
	Engineering, Ops or Other Labor	[redacted]
	Indirects / AFUDC	$[redacted]
	Sub-Total	$[redacted]
10%	Contingency	$[redacted]
	Sales Tax	[redacted]
TOTAL COSTS		$[redacted]

Assumptions/Qualifications

Note all details and assumptions related to project estimate development including:
Access to facilities
Weather/seasonal affects
Labor availability
Project duration
Basis for cost estimates or units of measure
Contingency assumptions and if applied at project total or component level

Maywood No 1

Modernization Project Estimate Summary			Planned Year 2020
WO Number (If Applicable)	Financial Number	Total Project Cost	TDSIC Program Category
517721	Maywood No. 1	$[redacted]	Circuit Rebuilds

Description of Work

Upgrade and Rehabilitate 13.2KV Overhead Distribution Circuit to current design standards. Location: Along alley from Farmsworth Road and Rybolt Road to Raymond (Airport)

Total Project Cost Summary

Cost Category		Project Cost Calculations	
Contract Labor	$[redacted]	Subtotal	$[redacted]
IPL Labor	[redacted]	Contingency	$[redacted]
Materials	$[redacted]	Subtotal + Contingency + Sales Tax	$[redacted]
Indirects/AFUDC	$[redacted]	E&S Loading	$[redacted]
		A&G Loading	
Sales Tax	$[redacted]	Total Loadings	$[redacted]
		Subtotal + Contingency + Loadings	$[redacted]
		Total Project Cost	$[redacted]

Public Appendix 8.9 Class 3 Estimate Example

Pole Replacement Project - Class 3 Estimate

	Type Percent	Average Annual Failures	Type Replaced Annually	Unit Replacement Cost	Replacemnt Cost per Type
13.2kv 1-Phase	75.00%	330	248	$[redacted]	$[redacted]
13.2kv 3-Phase	20.00%	330	66	$[redacted]	$[redacted]
13.2kv Double Ckt	1.25%	330	4	$[redacted]	$[redacted]
34.5kv 3-Phase	1.25%	330	4	$[redacted]	$[redacted]
34.5kv Double Ckt	1.25%	330	4	$[redacted]	$[redacted]
34.5kv 13.2kv UB	1.25%	330	4	$[redacted]	$[redacted]
Sub Total	100%	1,980	330		[redacted]
Treatment of Poles	16,500	330	16,170	$[redacted]	$[redacted]
Total Annual Cost Total					$3,192,288

Escalation 2.0% Estimate Year 2019

Plan Year	1	2	3	4	5	6	7
Year	2020	2021	2022	2023	2024	2025	2026
Cost	$3,256,134	$3,321,256	$3,387,682	$3,455,435	$3,524,544	$3,595,035	$3,666,935

Approx Number of Distribution poles on system	165,000
Approx Number of Annual Distribution Pole Inspections	16,500
Average failure rate	2.0%
Approx number of reject poles per year	330

PUBLIC Appendix 8.10 Class 4 Estimate Example

15 kV Switchgear Replacement Cost Breakdown (6 feeders)

6 Feeders											
Description	Qty	UoM	Unit/Mhr	Total Mhrs	Crew Rate	Labor Cost Total	Unit Material	Total Material	Unit Subcontract	Total Subcontract	Total Cost
Switchgear	6	ea	80	480	[redacted]						
Throat Addapter	1	ea	80	80	[redacted]						
DC Distribution Upgrade	1	ea	50	50	[redacted]						
Foundation Replacement	1	ea	200	200	[redacted]						
Stone	1	ea	20	20	[redacted]						
Relay/SCADA communication	1	ea	150	150	[redacted]						
Relay Engineering Access	1	ea	40	40	[redacted]						
Cabling					[redacted]						
Control Cables & conduits	500	ft	0.4	200	[redacted]						
Exit Cables	300	ft	0.94	282	[redacted]						
Ducts	300	ft	1	300	[redacted]						
New Manhole	1	ea	300	300	[redacted]						
					[redacted]						
Freight	1	ea			[redacted]						
Moving / Off loading	1	ea		20	[redacted]						
					[redacted]						
SubTotal					[redacted]						
					[redacted]						
Project Engineering 10%					[redacted]						
Project Management 5%					[redacted]						
Project Safety 5%					[redacted]						
					[redacted]						
SubTotal					[redacted]						
					[redacted]						
Project Contingency 10%					[redacted]						
AFUDC & Indirect Capital 10%					[redacted]						
					[redacted]						
Total				2122	[redacted]						

Appendix 8.11 Risk Reduction Benefit Monetization Report

Risk Reduction Benefit Monetization Report

Indianapolis Power & Light Company

IPL TDSIC Risk Reduction Benefit Monetization Report
Project No. 104713

Risk Reduction Benefit Monetization Report

prepared for

Indianapolis Power & Light Company
IPL TDSIC Risk Reduction Benefit Monetization Report
Indianapolis, Indiana

Project No. 104713

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
C&I	Commercial and Industrial
COF	Consequence of Failure
DOE	Department of Energy
ICE	Interruption Cost Estimate
IPL	Indianapolis Power & Light Company
LOF	Likelihood of Failure
NPV	Net Present Value
OH	Overhead
TDSIC	Transmission, Distribution and Storage System Improvement Charge
UG	Underground

1.0 INTRODUCTION AND OVERVIEW

Indianapolis Power and Light (IPL) engaged the services of Burns & McDonnell Engineering Company, Inc. (Burns & McDonnell) to monetize some of the risk reduction benefits of the Risk and Investment assessment (see IPL TDSIC Risk & Investment Report). This report outlines the approach Burns & McDonnell employed in monetizing risk reduction and the results of the analysis. The monetization analysis leverages a significant portion of the Asset Risk Model. For brevity, this report assumes the reader has read the IPL Transmission, Distribution and Storage System Improvement Charge (TDSIC) Risk & Investment Report to understand the more detailed analysis rather than duplicate sections here. However, it has been written to also communicate the general approach and results without the need to read the more detailed report.

The risk reduction benefit monetization was performed on the following projects: Substation Assets Replacement, Circuit Rebuilds, 4kv Conversion, XLPE Cable Replacement, and Remote End – Breaker Relay/Upgrades. At a high level, the risk reduction benefits were monetized at the asset level based on the following:

- 20 year evaluation profile
- Likelihood of Failure Profile calculated using the survivor curves and effective age based on the asset health algorithms
- Monetizing Consequence of Failure
    - Customer Reliability – using the DOE ICE Calculator
    - Reactive Failure Costs – assuming 40 percent cost adder to proactive replacement
- Monetized Risk Profile = Likelihood of Failure x Monetized Consequence of Failure
- Avoided cost calculated as the difference between the "Do Nothing" and Investment Scenario monetized risk profiles

The following sections outlines the risk reduction benefit monetization approach and results.

2.0 APPROACH

2.1 Financial Assumptions

The monetization approach described herein assumes the following discounted cash flow assumptions:

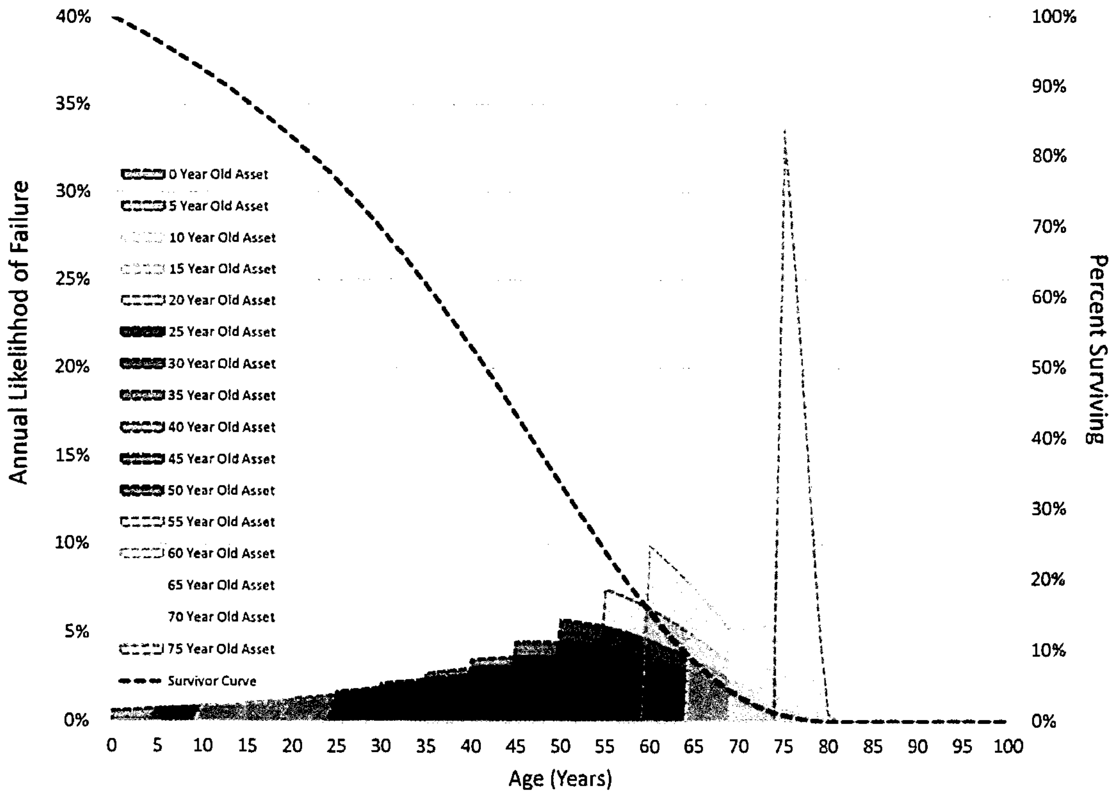
- An analysis period of 20 years
- Escalation rate of 2%
- A discount rate of 6.6%

2.2 Likelihood of Failure

The likelihood of failure (LOF) portion of the asset risk monetization utilized the developed survivor curves and effective age using Asset Health Indices outlined in the Asset Risk and Investment Assessment Report (see Section 2.2). The evaluation covered 1,690 substation assets and 218,175 overhead (OH) and underground (UG) sections. For each asset the LOF profile was estimated for the 'Do Nothing' and Investment scenarios.

Figure 2-1 shows the annual discrete LOF forecasts for an example survivor curve of an asset for various ages. The area of under each likelihood density function equals 100 percent. As the figure shows, younger assets have LOF profiles similar to normal distribution curves. But as assets age and the 100 percent is divided over fewer and fewer years, the annual discrete LOF increase dramatically, especially for assets past the average service life.

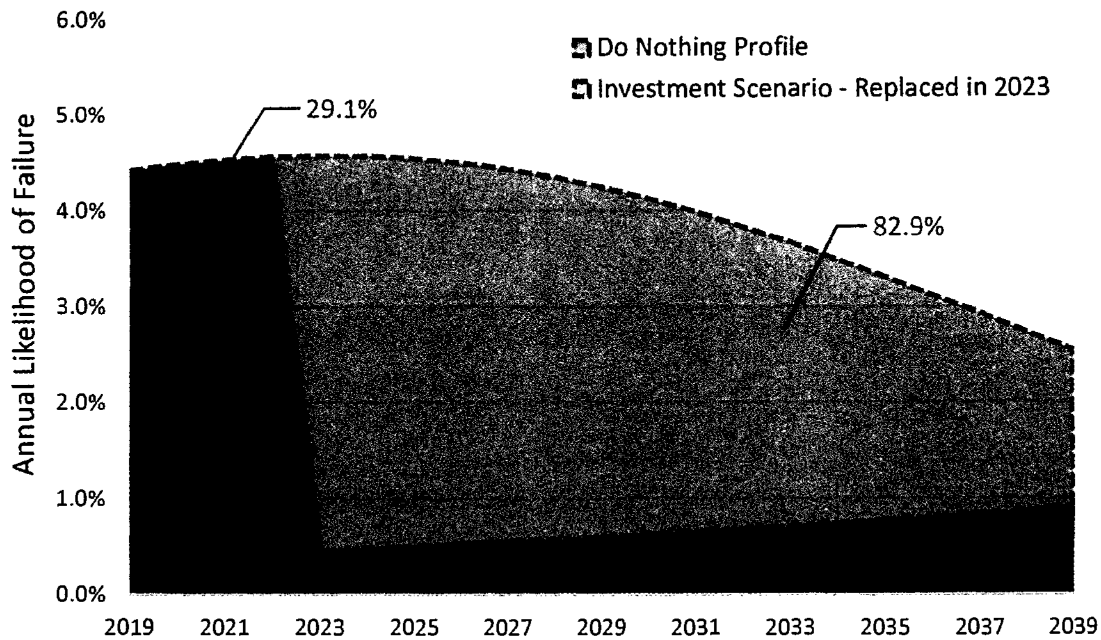
Figure 2-1: Likelihood of Failure Profiles for Various Asset Ages



The monetization approach considers the first 20 years of the LOF profile. It should be noted, that the likelihood of failure approach utilized in the Asset Risk Model and described in Burns & McDonnell's IPL TDSIC Asset Risk & Investment Assessment Report is over a 10 year period as outlined in Section 2.2.2. The asset risk monetization approach employs the same methodology for likelihood of failure using Survivor curves and asset health indices to estimate effective age. The main difference is the term used, 10 years versus 20 years.

Figure 2-2 shows the annual probabilities of failure over a 20-year period for Guion 132-39, a 138kV oil circuit breaker. The figure includes the LOF forecasts for both the 'Do Nothing' scenario and an Investment scenario where the asset is replaced in Year 4 of the TDSIC plan. With this approach, the monetization evaluation includes residual risk of the asset after it has been replaced. The difference between the area under each LOF forecast curve (82.9% and 29.1%) provides the benefit for the likelihood of failure component (53.8% benefit).

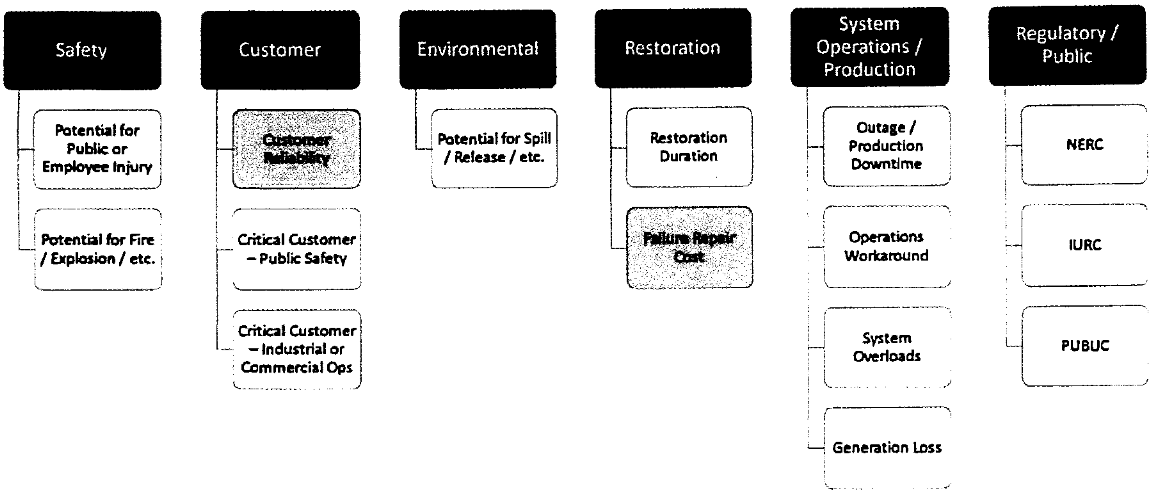
Figure 2-2: 'Do Nothing' and Investment Scenario Likelihood of Failure Forecasts



2.3 Monetized Consequence of Failure

The Asset Risk Model includes consequence scoring for 6 categories. Figure 2-3 provides a summary of the consequence of failure (COF) framework used in the Asset Risk Model. Section 2.3 of the Burns & McDonnell Asset Risk Model & Investment Report provides additional details on this COF framework. For this monetization evaluation the subcategories highlighted in green, Customer Reliability and Failure Repair Cost of the Restoration, were monetized. The sections below describe the approach to monetize these two subcategories.

Figure 2-3 Asset Risk Model: Consequence of Failure Criteria



2.3.1 Failure Repair Costs or Reactive Replacement Costs

This consequence category represents a direct cost to the utility that is passed through to customers. Both the Asset Risk Model and Monetization Analyses assume reactive replacement costs are approximately 40 percent more than proactive. Factors that contribute to this increase include:

- Overtime
- Premiums to make last minute purchase of equipment and materials
- Mobilization and rework related to making temporary fixes and returning to effect permanent repairs / replacements
- Schedule disruption in reassigning crews, previously deployed on other work, on emergent activities

2.3.2 Residential and Small C&I Customer Reliability

The Asset Risk and Investment Analysis scores customer reliability consequence for residential and small commercial and industrial (C&I) customers by using the DOE ICE Calculator and converts the interruption costs to a consequence score consistent with the holistic and integrated COF framework. The monetization analysis uses the same interruption costs for primary and transmission conductor, while utilizing a conservative assumption that pole and tower failures will not results in a monetized reliability cost to customer.

The interruption costs were first determined by developing outage scenarios, which were then assigned to each asset. The scenarios were developed by analyzing historical system outages for the various asset classes taking into account the number of customers an asset would serve. Additionally, the scenarios assume deployment of the advanced control system. Each outage scenario was modeled within the DOE ICE Calculator to determine the interruption costs on an asset by asset basis.

The Interruption Cost Estimate (ICE) Calculator is an electric reliability planning tool developed by Freeman, Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy (DOE).

The analysis includes 23 outage scenarios. One example scenario is a 3-phase overhead primary on the backbone. This example scenario assumes 875 customers would be out of service for 5 minutes before the advanced control system sectionalizes the circuit. Following the sectionalizing, the scenario assumes 400 customers to be out of service for an additional 55 minutes (60 minute outage in total). Review of outage records for this scenario indicates an average time to restore service of 60 minutes.

3.0 RESULTS

Figure 3-1 shows the annual cash flows (escalated nominal) profile by cash flow type for the monetized benefits and TDSIC investment. The figure shows net positive benefits by year 5.

Figure 3-1 Annual Cash Flow Profile

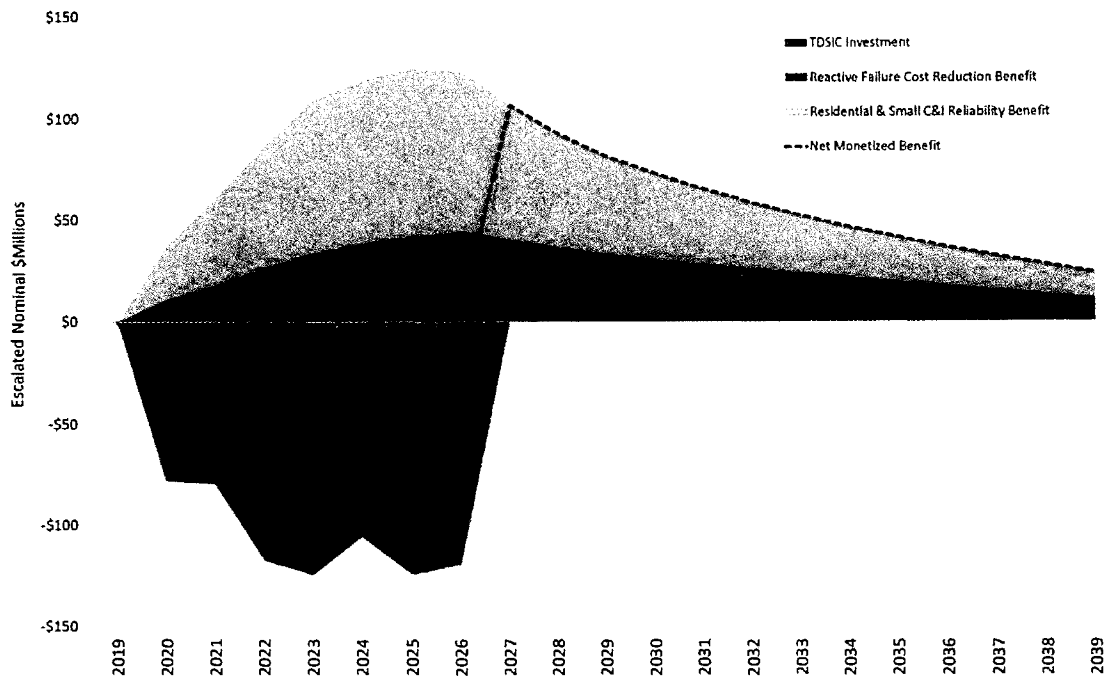


Figure 3-2 provides an alternative view showing the cumulative annual cash flows to date. The monetized benefits provide a net benefit of approximately $658 million over the 20 year period. Additionally, the profile shows a break-even point by year 8.

Figure 3-3 provides a summary of the 20 year escalated nominal cash flows and Net Present Value (NPV) by cash flow type. The monetized benefits provide total (or gross) NPV benefits of $840 million and net benefits of $268 million.

Figure 3-2 Cumulative Annual Cash Flow Profile

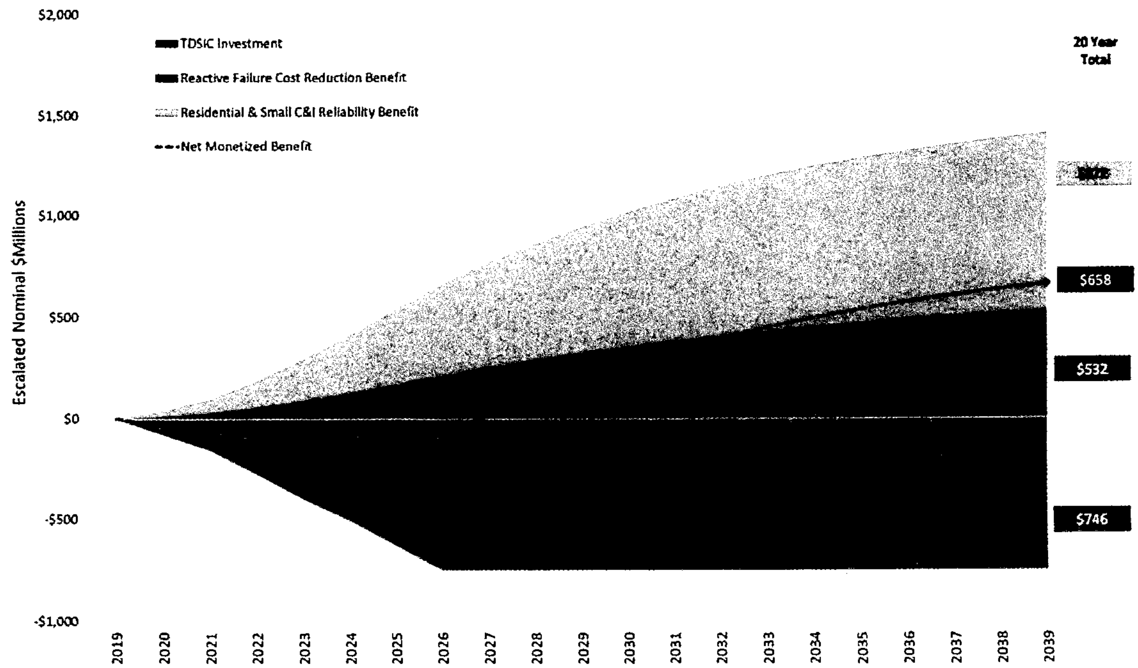
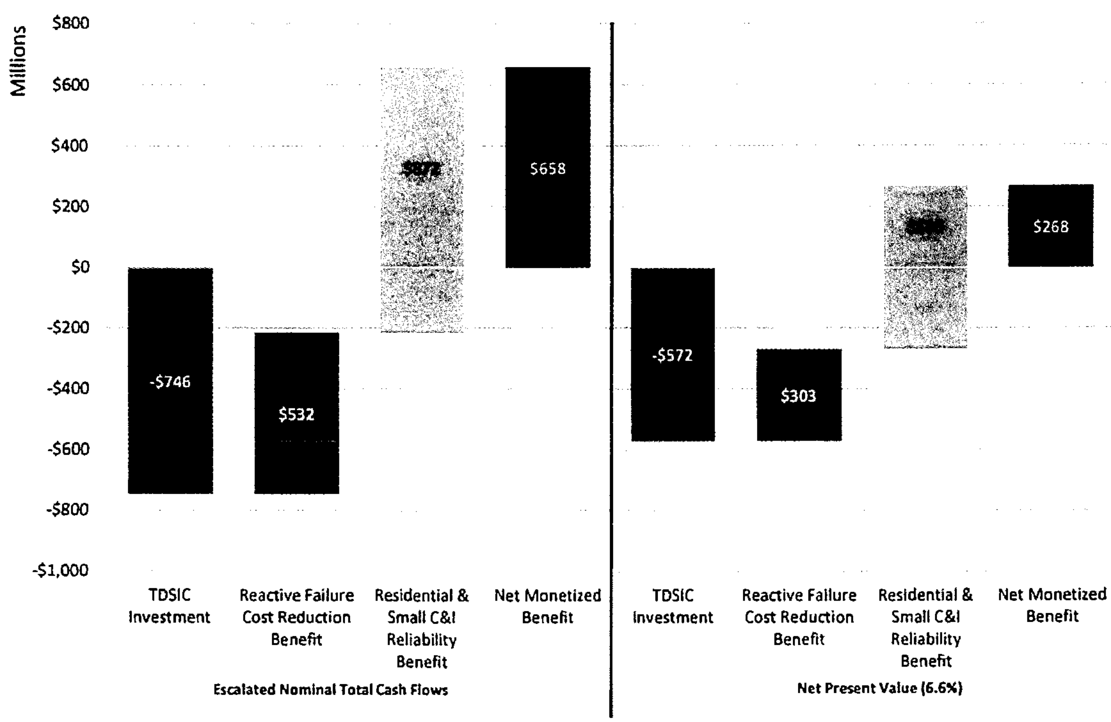


Figure 3-3 Cash Flow and NPV Summary



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OFFICIAL EXHIBITS

FILED
June 18, 2020
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IURC
PETITIONER'S
EXHIBIT NO. 2
9-11-20 AT
DATE REPORTER

PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY PURSUANT TO IND. CODE § 8-1-39-9 FOR: (1) APPROVAL OF AN ADJUSTMENT TO ITS ELECTRIC SERVICE RATES THROUGH ITS TRANSMISSION, DISTRIBUTION, AND STORAGE SYSTEM IMPROVEMENT CHARGE ("TDSIC") RATE SCHEDULE, STANDARD CONTRACT RIDER NO. 3; AND (2) AUTHORITY TO DEFER 20% OF THE APPROVED CAPITAL EXPENDITURES AND TDSIC COSTS FOR RECOVERY IN PETITIONER'S NEXT GENERAL RATE CASE.	)	**CAUSE NO. 45264 TDSIC 1**

PETITIONER'S SUBMISSION OF DIRECT TESTIMONY OF
<u>CHAD A. ROGERS</u>

Indianapolis Power & Light Company ("IPL" or "Petitioner"), by counsel, hereby submits the direct testimony and attachments of Chad A. Rogers.

Respectfully submitted,

Jeffrey Peabody

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing was served this 18th day of June, 2020, by email transmission, hand delivery or United States Mail, first class, postage prepaid to:

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ATTORNEYS FOR APPLICANT
INDIANAPOLIS POWER & LIGHT COMPANY

VERIFIED DIRECT TESTIMONY

OF

CHAD A. ROGERS

ON BEHALF OF

INDIANAPOLIS POWER & LIGHT COMPANY

<u>**SPONSORING IPL ATTACHMENTS CAR-1 – CAR-6**</u>

VERIFIED DIRECT TESTIMONY OF CHAD A. ROGERS
ON BEHALF OF
INDIANAPOLIS POWER & LIGHT COMPANY

Q1. Please state your name, employer and business address.

A1. My name is Chad A. Rogers. I am employed by Indianapolis Power & Light Company ("IPL" or "Company"), whose business address is One Monument Circle, Indianapolis, Indiana 46204.

Q2. What is your position with IPL?

A2. I am Senior Program Manager in Regulatory Affairs.

Q3. Please describe your duties as Senior Program Manager.

A3. I provide financial, technical and regulatory analysis and manage various regulatory projects and filings.

Q4. Please summarize your educational and professional qualifications.

A4. I hold a Bachelor of Science Degree in Accounting and Finance from the Kelley School of Business at Indiana University. I also hold a Master of Business Administration Degree from the Lacy School of Business at Butler University. I received my Certified Public Accountant ("CPA") license for the State of Indiana and have fulfilled the necessary educational requirements to allow use of the CPA designation. I have also attended various regulated utility training courses such as Edison Electric Institute ("EEI") Utilities Accounting Courses (Intro and Advanced), EEI Electric Rates Advanced Course, and PWC Rate Case Experience Course. I also am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA").

Q5. What is your previous work experience?

A5. I have been an employee of IPL since April 5, 2006, initially as a Senior Accountant and later as a Section Leader in the accounting and external reporting team. From June 2009 to September 2013, I worked as a Senior Analyst and later as a Section Leader in Financial Planning and Analysis. I have been in Regulatory Affairs since September 2013 where I was a Senior Analyst until becoming a Senior Program Manager in 2018.

From February 2004 to April 2006, I was employed by Cinergy Corporation (now Duke Energy). At Cinergy, I held a Senior Accountant role and was responsible for various accounting, financial analysis, and financial reporting duties.

From January 2001 to January 2004, I was employed by KPMG LLP as a Senior Associate in assurance services. In that position, I was responsible for audits, reviews, compilations, and control assessments for clients spread over a wide range of industries.

Q6. Have you previously testified before this Commission?

A6. Yes. I provided testimony in IPL's Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Plan Filing in IURC Cause No. 45264. I have also provided testimony in IPL's Environmental Compliance Cost Recovery Adjustment proceedings, beginning in IURC Cause No. 42170-ECR-28. I also provided testimony in IPL's Electric rate case, IURC Cause No. 45029 ("IPL's most recent rate case").

Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of my testimony is to:

1. Provide an overall summary of IPL's requested relief.

2. Discuss how IPL's TDSIC 1 filing in this proceeding comports with the TDSIC Statute and certain accounting treatment approvals in the Order approving IPL's TDSIC Plan.
3. Discuss IPL's proposed netting of depreciation expense.
4. Explain why the WACC reflected in the Company's proposed revenue requirement is reasonable and the Commission should make no adjustment to the Company's pretax return.
5. Estimate the effect of IPL's TDSIC Plan on retail rates and charges over the plan term.

Q8. Are you sponsoring any attachments?

A8. Yes. I sponsor IPL Attachment CAR - 1 thru 4 which contain and support the estimate of the effect of IPL's TDSIC Plan on retail rates charges over the Plan term. I also sponsor IPL Attachment CAR - 5 which contains IPL Witness AMM Attachment 3 from IPL's most recent rate case. This attachment summarized the regulatory adjustment mechanisms available to the proxy group of electric utilities used in that case to estimate the cost of equity. I also sponsor IPL Attachment CAR - 6 which is the Petition in this proceeding.

Q9. Were these attachments prepared or assembled by you or under your direction and supervision?

A9. Yes.

Q10. Are you submitting workpapers?

A10. Yes. I am submitting workpapers in their native format that are the same as or support the attachments included with my testimony. These workpapers are the electronic spreadsheets and were prepared or assembled by me or under my direction and supervision.

1. REQUESTED RELIEF

Q11. What relief is IPL requesting?

A11. IPL is requesting approval of an adjustment to its electric service rates through a TDSIC in accordance with I.C. § 8-1-39-9. This relief effectuates the timely recovery of 80% of approved capital expenditures and TDSIC Costs, as defined in I.C. § 8-1-39-7, in connection with IPL's approved TDSIC Plan and deferral of the remaining 20% to be recovered as part of IPL's next general rate case. IPL's TDSIC Plan was approved in IURC Cause No. 45264. IPL also requests approval to adjust Petitioner's authorized return for purposes of I.C. § 8-1-2-42(d)(3) to reflect the incremental earnings that will result from this TDSIC Rider filing upon Commission approval in accordance with I.C. §8-1-39-13(b).

As ordered by the Commission, IPL will file semi-annual TDSIC riders, staggered by six months: one to establish the TDSIC rider factors and one to update the TDSIC Plan. In this TDSIC Rate Update filing, the following Witnesses present testimony to support the requested TDSIC factors:

Chad A. Rogers – Regulatory Policy	– Provide an overall summary of IPL's requested relief. – Discuss how IPL's TDSIC 1 filing in this proceeding comports with the TDSIC Statute and certain accounting treatment approvals in the Order approving IPL's TDSIC Plan. – Discuss IPL's proposed netting of depreciation expense. – Explain why the WACC reflected in the Company's proposed revenue requirement

	is reasonable and the Commission should make no adjustment to the Company's pretax return. – Estimate the effect of IPL's TDSIC Plan on retail rates and charges over the Plan term.
James (Jim) William Shields Jr. – Project Management	– Provide an overview of IPL's approved TDSIC Plan. – Provide progress of Projects. – Present TDSIC capital investments as of March 31, 2020. – Describe the capital investments. – Identify cost variances and justify the variance for specific projects that have an actual cost greater than the previously approved estimate.
Natalie Herr Coklow – Regulatory Accounting	– Present and support the TDSIC revenue requirement calculations. – Support timely recovery of 80% of the calculated TDSIC revenue requirement, and deferral of 20% of the calculated TDSIC revenue requirement for future recovery in IPL's next general rate case. – Explain how Plan development costs and depreciation and property tax expenses are treated in the calculation of the revenue requirement. – Discuss the evaluation of the change in the TDSIC revenue requirement compared to the two percent (2%) of total annual revenues in a 12-month period cap, as required by the TDSIC Statute. – Discuss the impact of the TDSIC factors proposed in this filing. – Present the tariff pages for the TDSIC Rider.

2. TDSIC STATUTE & TDSIC PLAN ORDER

Q12. Does this filing comport with the TDSIC Statute set forth in Indiana Code ("I.C.") §8-1-39-9?

A12. Yes. The Commission approved IPL's TDSIC Plan under I.C. § 8-1-39-10 ("Section 10") and cost recovery pursuant to I.C. § 8-1-39-9 ("Section 9"). In this proceeding, IPL is seeking cost recovery pursuant to Section 9.

Q13. Has IPL used the customer class revenue allocation factors based on firm load approved in IPL's most recent basic rate case order as required by Section 9(a)(1)?

A13. Yes. This issue was resolved in IPL's most recent basic rate case. IPL Witness Coklow used the approved TDSIC allocation factors in IPL Attachment NHC-2 to calculate the appropriate customer class factors (IURC Cause No. 45029, Settling Parties Joint Exhibit 1 Settlement Attachment E).

Q14. Has IPL included its TDSIC Plan as part of this filing as required by Section 9(a)2?

A14. Yes. As noted above, IPL's TDSIC Plan was approved by the Commission's order dated March 4, 2020 in Cause No. 45264 ("IPL TDSIC Plan Order"). IPL's TDSIC Plan was admitted to the record in that Cause as IPL Exhibit 2. This was a comprehensive exhibit. Appendix 8.7 to this exhibit set forth the cost estimates and year detail and plan projects by FERC account (sortable list). IPL's Petition included a request for administrative notice to the IPL TDSIC Plan. For administrative efficiency IPL proposes that going forward, IPL's TDSIC Rider filings include Appendix 8.7 only to comply with the Section 9(a) requirement that the petition include the public utility's TDSIC Plan. IPL Witness Shields sponsors IPL Confidential Attachment JWS-1, which reconciles the cost estimates presented in Appendix 8.7 of IPL's approved TDSIC Plan with actual TDSIC capital costs as of March 31, 2020.

Q15. Are the TDSIC projects included for recovery eligible transmission, distribution, and storage system improvements under I.C. § 8-1-39-2?

A15. Yes. The projects implemented in IPL's TDSIC Plan were undertaken for the purpose of safety, reliability, or system modernization and were found by the Commission to constitute eligible transmission, distribution, or storage system improvements within I.C.

§ 8-1-39-2. IPL TDSIC Plan Order, p.21. The Commission Order authorized TDSIC treatment for the projects in IPL's TDSIC Plan in accordance with I.C. § 8-1-39-10(b). IPL TDSIC Plan Order, p. 24.

Q16. Were any of the TDSIC projects included for recovery in this Cause in IPL's rate base in IURC Cause No. 45029 (IPL's most recent rate case)?

A16. No. These are new projects which have not previously been included in IPL's rate base. The rate base cutoff in IPL's most recent rate case was June 30, 2017 with major project additions and certain net post-test year generation additions through April 2018. TDSIC Plan Development costs did not begin until May 2018. Additionally, the Order approving IPL's TDSIC Plan confirms that the proposed projects "were not included in IPL's most recent rate case." IPL TDSIC Plan Order, p. 21.

Q17. I.C. § 8-1-39-9(d) states that a public utility may not file a petition under I.C. § 8-1-39-9(a) within nine (9) months after the date on which the Commission issued an order changing Petitioner's basic rates and charges. When was IPL's most recent electric rate case order issued?

A17. The final order in IPL's most recent rate case (Cause No. 45029) is dated October 31, 2018, which is more than nine months prior to the filing of this TDSIC.

Q18. Does IPL intend to file a basic rates and charges petition with the Commission prior to the expiration of the 7-Year TDSIC Plan, as required by I.C. § 8-1-39-9(e)?

A18. Yes, IPL intends to petition the Commission for review and approval of its basic rates and charges prior to the expiration of the 7-year TDSIC Plan.

Q19. I.C. § 8-1-39-9(f) states that a public utility may file a Section 9 petition not more than one time every six months. Please provide an overview of IPL's planned TDSIC rider calendar.

A19. The Order approving IPL's TDSIC Plan states that "IPL shall file its TDSIC Plan updates and TDSIC rate updates separately on an annual basis, staggered six months from each other, as subdockets in this Cause under the cause number 45264 TDSIC X, with its first tracker filed on or before July 1, 2020." IPL TDSIC Plan Order, p. 29. The following schedule meets this requirement:

Table 1: IPL's TDSIC Rider Schedule

Filing	Type	Actual Costs Cutoff	Filing Date	Order Date	Rates Effective Period	Reconciliation Period
TDSIC 1	Rate	Mar 31, 2020	Mid Jun 2020	Oct 2020	Nov 2020 – Oct 2021	
TDSIC 2	Plan Update		Mid Dec 2020	Apr 2021		
TDSIC 3	Rate	Mar 31, 2021	Mid Jun 2021	Oct 2021	Nov 2021 – Oct 2022	
TDSIC 4	Plan Update		Mid Dec 2021	Apr 2022		
TDSIC 5	Rate	Mar 31, 2022	Mid Jun 2022	Oct 2022	Nov 2022 – Oct 2023	Nov 2020 – Oct 2021
TDSIC 6	Plan Update		Mid Dec 2022	Apr 2023		
TDSIC 7	Rate	Mar 31, 2023	Mid Jun 2023	Oct 2023	Nov 2023 – Oct 2024	Nov 2021 – Oct 2022
TDSIC 8	Plan Update		Mid Dec 2023	Apr 2024		
TDSIC 9	Rate	Mar 31, 2024	Mid Jun 2024	Oct 2024	Nov 2024 – Oct 2025	Nov 2022 – Oct 2023
TDSIC 10	Plan Update		Mid Dec 2024	Apr 2025		
TDSIC 11	Rate	Mar 31, 2025	Mid Jun 2025	Oct 2025	Nov 2025 – Oct 2026	Nov 2023 – Oct 2024
TDSIC 12	Plan Update		Mid Dec 2025	Apr 2026		
TDSIC 13	Rate	Mar 31, 2026	Mid Jun 2026	Oct 2026	Nov 2026 – Oct 2027	Nov 2024 – Oct 2025
TDSIC 14	Rate	Mar 31, 2027	Mid Jun 2027	Oct 2027	Nov 2027 – Oct 2028	Nov 2025 – Oct 2026
TDSIC 15	Rate	Mar 31, 2028	Mid Jun 2028	Oct 2028	Nov 2028 – Oct 2029	Nov 2026 – Oct 2027

Q20. Please describe IPL's planned TDSIC 2 Plan Update filing.

A20. In its TDSIC 2 Plan Update filing, IPL will present the progress of the TDSIC projects and compare spending levels to the previously approved TDSIC Plan estimates. IPL will also present any proposed changes to the Plan and provide specific justification for the Commission to approve the recovery of costs in excess of approved estimates. IPL TDSIC Plan Order, p. 29.

IPL will also update certain cost estimates based on refined engineering performed for certain projects. Specifically, IPL plans to present Class 2 cost estimates for certain TDSIC Year 3 projects. Due to travel restrictions and social distancing requirements of IPL and contractor personnel caused by the COVID-19 pandemic, Class 2 engineering of some of these projects is expected to be delayed and likely not available for presentation in the December 2020 filing. In order to provide timely Plan updates and adhere to the Order requirements outlining the six-month staggering of TDSIC Plan Update rider filings, IPL will file TDSIC 2 as scheduled in December 2020, and proposes to file supplemental information that will include the remaining Class 2 cost estimates for Year 3 projects when complete. IPL anticipates the timing of the TDSIC supplemental filing to be in the first half of 2021. IPL Witness Shields discusses the anticipated delay in engineering estimates in more detail. IPL will know more closer to the filing of TDSIC 2 and will seek to discuss procedural details with the OUCC.

Q21. Did IPL meet with the OUCC and interested stakeholders prior to filing its petition in this Cause?

A21. Yes. IPL met with the OUCC and interested stakeholders to preview the accounting and ratemaking schedules and to discuss topics of interest.

Q22. Please summarize the findings and approvals made by the Commission in the IPL TDSIC Plan Order which are reflected in this TDSIC rate filing.

A22. The Commission Order included the following related to the accounting ratemaking in the TDSIC Rider:

- authorized TDSIC treatment for the improvements described in IPL's TDSIC Plan including costs incurred starting on August 1, 2019. IPL TDSIC Plan Order, p. 24.
- found the best cost estimate of the eligible improvements included in the Plan is the $1.2 billion estimate provided by IPL. IPL TDSIC Plan Order, p. 29.
- authorized IPL to defer post-in-service TDSIC Plan costs on an interim basis until such costs are included in TDSIC Rider rates or in future base rates. IPL TDSIC Plan Order, p. 29.
- approved IPL's request for authority to defer its plan development costs for recovery via IPL's future TDSIC tracker pursuant to I.C. § 8-1-39-9 over a three-year amortization period. IPL TDSIC Plan Order, p. 29.
- approved IPL's proposals to utilize the applicable depreciation rates approved in its most recent rate case and to recover depreciation prospectively. IPL TDSIC Plan Order, p. 29.
- directed IPL to remove the gross up for taxes associated with the 20% deferred regulatory asset from future filings. IPL TDSIC Plan Order, p. 25.
- found it appropriate to explore a reasonable adjustment when determining the WACC in TDSIC 1 to address the OUCC's depreciation netting concern and the IPL Industrial Group's (IG) concerns with the shifting of risks based on the plan. IPL TDSIC Plan Order, p. 27.

Q23. Has IPL complied with the accounting and ratemaking treatment approved in the TDSIC Plan Order in developing the proposed TDSIC factors?

A23. Yes. IPL Witness Coklow presents the accounting schedules and utilized the accounting treatment discussed above in determining the applicable TDSIC Rider factors.

Q24. What specific costs were included in the development of the proposed TDSIC factors for which IPL is requesting Commission approval?

A24. IPL included eligible TDSIC Costs as defined under I.C. § 8-1-39-7, including depreciation expense, property taxes, and pretax returns. IPL also included the amortization of plan development costs as authorized in the TDSIC Plan filing order discussed above.

Q25. How is IPL's treatment of income taxes on the deferred regulatory asset in this filing compliant with the Commission's TDSIC Plan Order?

A25. IPL has recorded the 20% deferral related to income taxes to a separate regulatory asset account to facilitate the treatment ordered by the Commission. In the IPL TDSIC Plan Order (p. 25), the Commission stated:

> **Recovery of Income Taxes on Deferred Regulatory Asset.** Mr. Blakley raised a concern that IPL should not recover income taxes on the same earnings twice when the 20% deferred regulatory asset is included in IPL' s next general rate case. We agree and find that IPL shall remove the gross up for taxes associated with the 20% deferred regulatory asset from future filings.

IPL Witness Coklow identified the portion of the deferral for income tax and presented the balance separately on <u>IPL Attachment NHC-10</u>. IPL will continue to reflect the deferred regulatory asset related to income tax recovery on this schedule which can then be excluded from the gross up of taxes in a future rate case filing.

3. <u>"OTHER INFORMATION" IN CONSIDERING THE APPROPRIATE PRETAX RETURN</u>

Q26. Please explain how IPL addressed the OUCC's concern that the TDSIC Rider revenues for new assets should be offset with the discontinued depreciation expense on the retirement of the replaced assets. IURC Cause No. 45264 Order pp. 8-9, 26-27)?

A26. As an initial matter, I continue to disagree with the OUCC's position that IPL's previous proposal is unreasonable. I addressed this in my rebuttal in Cause No. 45264. That being said, to address this concern and to reduce controversy, IPL calculated depreciation expense on the retired and replaced assets and has included that depreciation expense amount as a credit to the depreciation expense recovery sought in this filing. The netting of depreciation expense is presented on IPL Attachment NHC-6 Line 2. This netting of depreciation is calculated in the same way IPL has implemented the netting of depreciation in past Environmental Compliance Cost Recovery Adjustment filings for Mercury Air Toxics Standard ("MATS") equipment. The effect of this adjustment is a reduction in the revenue that would otherwise have been recovered through the TDSIC rider, effectively reducing IPL's return on the new assets as compared to not reflecting the depreciation credit. This treatment sufficiently addresses the concern of netting depreciation expense on the assets retired as part of the TDSIC Plan. As discussed below, no adjustment to the pretax return is necessary.

Q27. Please summarize the IG's concern that the TDSIC mechanism "shifts risks based on plan approval." (IPL TDSIC Plan Order pp. 10 & 27)

A27. The IPL TDSIC Plan Order (p. 10) reflects that the IG's witness contended that "IPL's ROE approved in its most recent rate case reflects the risk of utility without a TDSIC plan and TDSIC plan pre-approval greatly reduces IPL's risk profile." I would note that the IG witness provided no analysis to support his summary contention. Cause No. 45264, IG Witness Collin p. 19. In my rebuttal in the Plan case, I indicated that this concern was premature, explaining that the IPL did not seek approval of revenue requirement at that time. As a result, the Company did not attempt to rebut this concern in the Plan case.

Q28. What does the term "risk profile" mean?

A28. I understand the IG's use of the term "risk profile" to refer to the threats to which an organization is exposed. In the Plan case, the IG witness viewpoint was that unlike the status quo, once the TDSIC Plan is approved, IPL will no longer face risk of disallowances or non-recovery.[1] IG Witness Collins said the only check and balance is with the Commission when the TDSIC Plan is presented for approval.[2] I disagree that it is appropriate to look only at risk-reducing factors and not also take into consideration factors that increase risk, such as the size of the capital expenditure needed to respond to the statutory objective of using a multi-year investment plan to address infrastructure needs systemically, which in turn provides efficiency and other benefits.[3] The undertaking of a capital plan the magnitude of IPL's TDSIC Plan increases capital expenditures beyond what would otherwise be undertaken. Without an approved TDSIC tracker, this would put pressure on IPL's 1) ability to satisfy credit metrics (operating cashflows metrics, EBITDA metrics, and debt metrics), 2) ability to issue debt at attractive rates, and 3) ability to maintain a balanced capital structure. Timely cost recovery through the TDSIC helps to offset these pressures.

Q29. Does Commission approval of IPL's TDSIC Plan mean that the Company will no longer face any risk of disallowance or non-recovery?

A29. No. The TDSIC Statute provides that an approved TDSIC Plan is eligible for 80% timely cost recovery and 20% cost deferral to a subsequent rate case as set forth in Section 9 of

[1] Cause No. 45264, IG Witness Collins p. 19.

[2] Cause No. 45264, IG Witness Collin p. 19.

[3] Cause No. 45264, IPL Witness Bentley Direct Testimony p. 9.

the Statute. While I agree that the 80% timely cost recovery is important to maintaining the financial health of the utility, I disagree that the statutory "TDSIC treatment" means the Company will no longer face any risk of disallowance or non-recovery or that there are no other checks and balances. As explained in the IPL TDSIC Plan Order (p. 23):

> After approval of a TDSIC plan, Ind. Code § 8-1-39-9 establishes procedures for TDSIC trackers, providing that "[a]ctual capital expenditures and TDSIC costs that exceed the approved capital expenditures and TDSIC costs require specific justification by the public utility and specific approval by the commission before being authorized for recovery in customer rates."

I would add that the IG has appealed the Commission's Order approving IPL's TDSIC Plan. The Industrial Group's appeals of other cases have resulted in other Commission TDSIC orders being vacated. Thus, while the Company is moving forward with the TDSIC Plan, doing so is not without risk given the Industrial Group's pending appeal.

Q30. Please discuss whether Commission approval of the IPL TDSIC Plan is "unlike the status quo" as indicated by the IG witness in the Plan proceeding.

A30. The TDSIC Statute has been part of Indiana's utility regulatory framework since 2013 and many other Indiana energy utilities have used this statute. In this regard, the Commission's March 2020 approval of the IPL Plan is not a departure from Indiana's existing a regulatory scheme. Furthermore, it is my understanding that Indiana has long allowed utilities to obtain pre-approval of investments from the Commission. I.C. § 8-1-2-23. Thus, I view the TDSIC Statute as changing the timeliness of cost recovery. Even then, this change is limited to 80% of capital expenditures and TDSIC Costs and is also tied to requirements that the utility defer 20% of its costs and file a basic rate case before expiration of the plan.

I.C. § 8-1-39-9(e). My understanding is that Indiana's utility regulatory framework does not otherwise impose a requirement on how often a utility must file a general rate case.

Thus, to the extent the TDSIC Statute changed the so-called status quo for Indiana ratemaking for T&D capital investment, it did so in two ways (*i.e.* timely cost recovery and a required general rate case). It is unreasonable to consider the impact of the timely cost recovery mechanism in a vacuum. As discussed below, when viewed holistically, a downward adjustment to IPL's TDSIC Rider pretax return is not warranted.

Q31. Is it reasonable to reduce IPL's pre-tax return in the TDSIC Rider in response to the IG's concern summarized above?

A31. No. I disagree that the ratemaking provisions of the TDSIC Statute warrant an adjustment to the Company's Commission's authorized pre-tax return. IPL's basic rates and charges have been reviewed in two recent cases (Cause Nos. 44576 and 45029). The Commission's decisions in these cases were issued March 15, 2016 and October 31, 2018, respectively, well after the enactment of the TDSIC Statute. The general rate case the Company is required to file under the TDSIC Statute, will provide another opportunity for the Commission to review the Company's rates and charges, including its authorized return.

The TDSIC Statute is designed to incentivize the expeditious investment in and improvement and modernization of Indiana's energy delivery system infrastructure. I am not aware instance where the Commission reduced the pre-tax return in a TDSIC Rider where the utility involved had at least one recent rate case.

As discussed above, the netting of depreciation expense reflected in IPL's proposed revenue requirement reduces the revenue IPL will receive and reasonably responds to the

Commission's Order. The netting has the effect of reducing IPL's pre-tax return; no other downward adjustment should be made.

The fact that IPL operates under certain rate adjustment mechanisms (also referred to as trackers) does not distinguish it from other firms in the electric utility industry. In IPL's most recent rate case, IPL's ROE witness explained that the existence of trackers is already reflected in the forward-looking cost of equity analysis because such mechanisms are industry wide:

> Adjustment mechanisms and cost trackers have been increasingly prevalent in the utility industry in recent years. In response to the increasing risk sensitivity of investors to uncertainty over fluctuations in costs and the importance of advancing other public interest goals such as reliability, energy conservation, and safety, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty and align the interest of utilities and their customers through a variety of adjustment mechanisms. Based largely on the expanded use of ratemaking mechanisms to address operational risks and investment recovery, Moody's upgraded most regulated utilities in January 2014. This is consistent with the view that investors perceive the impact of regulatory mechanisms to be an industry-wide factor. Just as a rising tide lifts all boats, ratemaking mechanisms have had an across-the-board impact on risk perceptions for virtually all utilities. (citations omitted)

IPL Witness McKenzie Direct Testimony, pp. 8-9.[4] In that case, IPL Witness McKenzie summarized the regulatory adjustment mechanisms available to the proxy group of electric utilities used to estimate the cost of equity which included infrastructure cost trackers that allow for recovery of new capital investment outside of a traditional rate case as well as a variety of other adjustment clauses. Witness AMM Attachment 3 (included with my testimony as IPL Attachment CAR-5). As shown by this attachment, timely cost recovery

[4] Citing Moody's Investors Service, "US utility sector upgrades driven by stable and transparent regulatory frameworks," *Sector Comment* (Feb. 2, 2014).

mechanisms are common among the proxy companies. IPL Witness McKenzie concluded, "Thus, while the mechanisms approved for IPL by the IURC would be regarded as supportive, investors would not view the risks of IPL as lower than the proxy group in these important respects." IPL Witness McKenzie Direct Testimony, p. 9. Thus, it would be incorrect to conclude that approval of the Company's TDSIC Plan and use of the statutory cost recovery has created a change in the Company's overall risk profile that would cause investors to specifically and measurably revise their return requirements.

Furthermore, the settlement in that recent rate case did not ignore that a TDSIC was available to IPL. To the contrary, the parties (including IG) settled on TDSIC allocation factors which were included in the Commission Order approving the Settlement, (Cause No 45029 Settling Parties Joint Exhibit 1 Settlement Attachment E).

Additionally, when paired with the introduction of a TDSIC Plan, the approval of a TDSIC rate mechanism is credit supportive and maintains the Company's opportunity to earn its previously authorized return. *Without* an approved mechanism to timely recover capital investment and TDSIC Costs related to IPL's TDSIC Plan investment, IPL's opportunity to earn its authorized return and maintain the metrics used to establish its credit rating would diminish.

Q32. Have you considered the Commission's recent discussion and findings on the topic of rate adjustment mechanisms and the utility's cost of equity?

A32. Yes. I reviewed the order in a recent litigated IPL rate case docketed as Cause No. 44576 (IURC 3/16/2016) (p. 42) and a litigated Indiana Michigan Power Company ("I&M") rate case docketed as Cause No. 44075 (IURC 2/13/2013) (p. 43). The order in the I&M case

(p. 31) states that the OUCC witness "did not make a specific adjustment to his COE estimate to recognize the influence of trackers. He explained to the extent that Indiana has trackers that are similar to those provided in other regulatory jurisdictions the effect of trackers is already captured by using an appropriately representative proxy group of state regulated electric utilities." This is consistent with the testimony of IPL Witness McKenzie I discussed above.

In each of these decisions, the Commission also distinguishes rate adjustment mechanisms addressed to regulatory lag from mechanisms addressed to volatility:

> Earnings risk can be seen in both an absolute and a volatility context - the absolute context serves as an effective marker to provide investors with an understanding of the base line earnings available, while the volatility context relates to the ability of the company to perform under a range of real world operating conditions. Trackers that adjust rates for incremental investments or for costs that are nearly certain to be increasing serve to adjust the base line earnings for post rate case changes and address issues primarily associated with regulatory lag. Trackers that adjust rates for cost changes that are more unknown and that are equally likely to decrease or increase address the risk of volatile earnings results. The general effect of these trackers is to reduce the uncertainty of the earnings that an investor can expect.

Id.

In this context, IPL's TDSIC is best described as a tracker that adjust rates for incremental investment and serve to adjusts the base line earnings for post rate case changes and addresses issues primarily associated with regulatory lag. The TDSIC is not a tracker that addresses the risk of volatile earnings. Because the TDSIC tracker is a means of reducing regulatory lag, the approval of the TDSIC should be viewed as maintaining (not reducing) IPL's risk profile. Rather, the TDSIC Rider is a tool that supports IPL's opportunity to earn its previously authorized return.

Finally, neither of the above decisions discussed this issue with respect to the TDSIC Statute or as a means of achieving the objectives of this statute. A Commission decision to reduce IPL's pre-tax return would be contrary to the policy underlying the TDSIC Statute as it would not reasonably incentivize investment in energy delivery infrastructure.

Q33. Does the financial community monitor the Company's financial condition and the Commission's ratemaking decisions?

A33. Yes. The financial community has established metrics that are used to monitor the ongoing financial condition of utility companies, including IPL. The financial community also monitors the regulatory environment in which IPL (and other utilities) operates. The regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk.

For example, Moody's states that 32.50 percent of the weight it gives to various factors considered in its ratings determinations are focused on cash flow because "[f]inancial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers."[5]

[5] Moody's Investors Service, *Rating Methodology; Regulated Electric and Gas Utilities*, June 23, 2017, pp. 4, 20.

S&P's Corporate Criteria Framework shows that cash flow-based metrics are integral to its assessment of the "Financial Risk Profile" which, when combined with the "Business Risk Profile" forms the basis of its rating assessment.[6]

S&P has explained that the regulatory structure is one of the most important factors in its credit rating analyses:

> For a regulated utility company, the regulatory regime in which it operates will influence its performance in profound ways. As such, Standard & Poor's Ratings Services' regulatory advantage assessment - - which informs both our business risk and financial risk scores - - is one of the most important factors in our credit analysis of regulated utilities.
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> ***
>
> Our assessment of a utility's regulatory regime rests on four pillars: regulatory stability, efficiency of tariff-setting procedures, financial stability, and regulatory independence... We believe these factors strongly influence a utility's credit quality and its ability to recover its costs and earn a timely return.[7]

As I noted above, the Commission has not previously required a downward adjustment in a pre-tax return under the TDSIC Statute where the utility had had recent rate cases. Furthermore, as also discussed above, doing so appears inconsistent with the policy objectives underpinning the Statute and fails to recognize the impact that significant capital investments have on the utility's financial health and the ongoing ability to maintain credit metrics. Thus, a Commission decision to make a downward adjustment to IPL's pre-tax return would be a departure from the Commission's previous actions and could be viewed

[6] Standard & Poor's Ratings Services, *Industry Report Card: The Outlook for U.S. Regulated Utilities Remains Stable on Increasing Capital Spending and Robust Financial Performance*, December 16, 2014, p. 7.

[7] Standard & Poor's Ratings Services, How Regulatory Advantage Scores Can Affect Ratings on Regulated Utilities, April 23, 2015, p. 2.

as a penalty on the Company for its efforts to pursue the goals of the TDSIC Statute in the largest City in the State of Indiana. As discussed below, while Moody's has rated IPL's outlook as "stable", this outlook is based on expectation that Indiana's credit supportive regulatory environment will continue. Moody's has identified a "perceived deterioration" of Indiana's regulatory environment as a factor that would lead to a downgrade.[8]

Q34. You indicated above that rate adjustment mechanisms are viewed by the financial community as credit supportive. Please explain.

A34. S&P has noted that it has "seen many state commissions approve alternative ratemaking techniques to traditional base rate case applications, which help utilities sustain cash flow measures, earning power, and ultimately, credit quality."[9]

In their recent reports regarding IPL, major credit rating agencies refer to tracking mechanisms available to IPL as being viewed as credit supportive.

More specifically, Moody's identified the "[e]xpected increase in capex pending IURC's final approval of the 2020-2027 [TDSIC Plan]" as one of the credit challenges backed by the Company" but noted: "[c]ost recovery mechanisms [that] allow for the recovery of certain cost and investments between rate cases" as a credit strength for IPL.[10] Moody's rated IPL's outlook as "stable" based on expectation that Indiana's credit supportive regulatory environment will continue but identified a "perceived deterioration" of Indiana's regulatory environment as a factor that would lead to a downgrade:

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[8] See QA 34 below referencing Moody's Investors Service, Credit Opinion, Indianapolis Power & Light Company, December 27, 2019, pp. 2-3.

[9] S&P RatingsDirect, *Industry Economic and Ratings Outlook: U.S. Regulated Utilities Expected To Continue On Stable Trajectory In 2013*, January 25, 2013, p. 4.

[10] Moody's Investors Service, Credit Opinion, Indianapolis Power & Light Company, December 27, 2019, p. 2.

> IPL's stable outlook reflects our expectation that its cash flows will continue to benefit from the credit supportive regulatory environment in the state of Indiana, that IPALCO's holding company debt will remain relatively constant, and that IPL's and IPALCO's ratios of cash flow from operations before changes in working capital (CFO pre-W/C) to debt will be sustained in the high and midteens respectively, pending the IURC's approval of IPL's revAMP and IRP programs.
>
> ***
>
> IPL's rating could face downward pressure upon a perceived deterioration of the regulatory environment in Indiana or upon a deterioration in IPL's credit metrics including if its ratio of CFO pre-W/C to debt falls below 18%, on a sustained basis .[11]

The Moody's report explained:

> Our view that the regulatory environment in Indiana is credit supportive considers that IPL's cash flows benefit from several recovery mechanisms that allow the utility to recover operational costs and investments in-between rate cases.[12]

The report added that "cost recovery mechanisms that reduce regulatory lag between rate cases" benefit cash flows and stated that the rating agency assumed that the Commission will allow IPL the 80/20 cost recovery provided in the TDSIC statute.[13]

S&P's rating report also shows that tracking mechanisms are viewed as supporting the utility's opportunity to earn its authorized return:

> The state's regulatory framework supports IPL's overall credit quality. Indiana's stable and transparent regulatory environment provides adequate opportunities to earn close to authorized returns. The company benefits from rate riders, which generally allow for the timely cost recovery of its fuel expenses and most of its incremental environmental capital spending,

[11] *Id.* pp. 2-3.

[12] *Id.* p. 3.

[13] *Id.* pp. 3-4.

> as well as a Transmission Distribution Storage System Improvement Charge (TDSIC) plan.[14]

A month after the Commission approved IPL's TDSIC Plan, S&P identified the Company's BBB credit rating as stable.[15] The report rated the Company's financial risk as "significant."[16] The same report viewed the Company's business risk as "excellent", citing timely cost recovery as being supportive of IPL's credit quality and supporting generally stable returns:

> Our assessment of IPL's business risk reflects its lower-risk, rate-regulated, vertically integrated electric utility operations. Although IPL has a below-average-sized customer base and generates much of its electricity from its coal-fired units, it effectively manages its regulatory risk under the IURC, earning generally stable returns. IPL further benefits from numerous rate riders, allowing for the timely cost recovery of its fuel expenses and the majority of its incremental environmental capital spending. Additionally, the company recently received approval for its TDSIC plan, which outlines a plan to invest in and earn a tracked return of and on capital spent for about $1.2 billion of investments between 2020 and 2027. We view this development as supportive of IPL's credit quality, since these investments support low risk regulated growth for the company.[17]

The rating agencies are consistent in viewing utilities that have access to tracking mechanisms as credit supportive as it is a sign of a constructive regulatory environment, one of the key considerations given by the rating agencies when assessing utilities.

Q35. What weighted average cost of capital ("WACC") did IPL use to calculate the pretax return component of TDSIC Costs used to calculate the TDSIC rates in this filing?

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[14] S&P Ratings Direct, Indianapolis Power & Light Company, April 14, 2020, p. 2.

[15] *Id.*

[16] *Id.*

[17] *Id.* p. 4.

A35. IPL utilized a WACC of 6.68% which is calculated using IPL's capital structure as of March 31, 2020, actual cost of long-term debt and preferred stock, and IPL's cost of common equity of 9.99% determined by the commission in IPL's most recent general rate proceeding. The WACC used to calculate pretax return is calculated by IPL Witness Coklow in IPL Attachment NHC-5.

In summary, this WACC is appropriately calculated using the cost of common equity determined by the Commission in IPL's most recent general rate proceeding. The "other information" identified in the Commission's IPL TDSIC Plan Order as warranting exploration does not warrant an adjustment to the WACC (or return on equity) for the following reasons:

1.) In this filing, IPL has addressed the concern of netting depreciation expense on the assets retired as part of the TDSIC Plan.

2.) IPL's most recent general rate proceeding in which the Commission approved settlement including a 9.99% ROE was approved in an Order dated October 31, 2018 which is less than two years from this TDSIC rate filing.

3.) IPL's most recent general rate proceeding also contemplated the availability of cost recovery mechanisms to utilities (including capital investment recovery trackers such as TDSIC) and IPL's risk profile, which is not changed based on the approval of a TDSIC.

4.) TDSIC and other timely cost recovery mechanisms are considered credit supportive by credit rating agencies which aids IPL in attracting capital at competitive rates which benefits IPL customers.

4. <u>TDSIC PLAN EFFECTS ON CUSTOMER RATES</u>

Q36. Has IPL calculated the aggregate increase in IPL's total retail revenues as a result of this TDSIC Rider?

A36. Yes. IPL Witness Coklow's testimony and attachments present a calculation of the aggregate increase in IPL's total retail revenues as a result of this TDSIC Rider and demonstrate such increase is less than the 2% statutory TDSIC limit set forth in I.C. § 8-1-39-14. IPL Witness Coklow also presents the proposed TDSIC 1 factors and impact of TDSIC 1 factors on residential bills.

Q37. What period will the TDSIC 1 factors, when approved, remain in effect?

A37. The TDSIC 1 factors, when approved, are planned to go into effect starting with the November 2020 billing cycle and remain in effect until new Rider factors are approved in IPL TDSIC 3, which is expected to be a period of approximately 12 months because IPL TDSIC 3 will seek approval of new factors for the November 2021 billing cycle.

Q38. Please identify the documents that have been marked for purposes of identification as <u>IPL Attachment CAR-1 through 4</u>.

A38. <u>IPL Attachment CAR-1</u> presents IPL's TDSIC Plan projected effects on retail rates and charges over the seven-year TDSIC Plan period. This attachment presents an estimate of the factors over the Plan period based on the current TDSIC project costs estimates and timing. I utilized the same revenue requirements calculation presented in the TDSIC Plan approval filing to estimate the impact of the TDSIC Plan on revenues with the following updates:

- I updated the estimate to recognize the rate base cutoff dates on March 31 for the rider filings.
- I also reflected the netting of depreciation expense on the retired and replaced assets as a credit to the depreciation expense recovery.
- Additionally, I applied the allocation factors and IPL's most recent volume forecast to estimate the effect the TDSIC Plan has on customer rates and charges.

IPL Attachment CAR-2 calculates IPL's TDSIC Plan projected rate base and depreciation expense utilized to calculate the rate impact in IPL Attachment CAR-1.

IPL Attachment CAR-3 calculates IPL's TDSIC Plan projected property tax expense utilized to calculate the rate impact in IPL Attachment CAR-1.

IPL Attachment CAR-4 presents IPL's TDSIC Plan projected depreciation expense on the retired and replaced assets to include as a credit in calculating the rate impact in IPL Attachment CAR-1.

Q39. What are the projected effects of the seven-year Plan impact on retail rates and charges?

A39. The projected effects are presented as follows and further detailed in IPL Attachment CAR-1 and presented below in Table 2.

Table 2: Projected effects of IPL's TDSIC Plan on retail rates and charges.

	TDSIC 1	TDSIC 3	TDSIC 5	TDSIC 7	TDSIC 9	TDSIC 11	TDSIC 13	TDSIC 14
Rate Base Cutoff	3/31/20	3/31/21	3/31/22	3/31/23	3/31/24	3/31/25	3/31/26	3/31/27
Rate Period	Nov 20-Oct 21	Nov 21-Oct 22	Nov 22-Oct 23	Nov 23-Oct 24	Nov 24-Oct 25	Nov 25-Oct 26	Nov 26-Oct 27	Nov 27-Oct 28
TDSIC Revenue Requirement ($M)	$ 4.2	$ 16.1	$ 32.9	$ 51.5	$ 71.6	$ 89.0	$ 104.1	$ 112.8
Total Revenue Change[1]	0.3%	0.8%	1.1%	1.2%	1.3%	1.1%	1.0%	0.6%
Estimated Rates ($/kWh)								
Residential	$ 0.000440	$ 0.001703	$ 0.003440	$ 0.005337	$ 0.007345	$ 0.008999	$ 0.010403	$ 0.011087
Small C&I	$ 0.000365	$ 0.001420	$ 0.002885	$ 0.004520	$ 0.006282	$ 0.007804	$ 0.009133	$ 0.009889
Large C&I - Secondary	$ 0.000146	$ 0.000867	$ 0.001766	$ 0.002770	$ 0.003850	$ 0.004784	$ 0.005580	$ 0.006055
Large C&I - Primary	$ 0.000226	$ 0.000570	$ 0.001163	$ 0.001831	$ 0.002566	$ 0.003222	$ 0.003775	$ 0.004139
Lighting	$ 0.000362	$ 0.001350	$ 0.002793	$ 0.004396	$ 0.006175	$ 0.007745	$ 0.009190	$ 0.010027

[1] Based on Total Retail Revenues per IPL Attachment NHC-11

5. CONCLUSION

Q40. In your opinion is the accounting and ratemaking relief sought by IPL in this Cause reasonable?

A40. Yes.

Q41. Does that conclude your prepared verified direct testimony?

A41. Yes.

VERIFICATION

I, Chad A. Rogers, Senior Program Manager, affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

Dated June 18, 2020.

Chad Rogers

Chad A. Rogers

INDIANAPOLIS POWER & LIGHT COMPANY
TRANSMISSION DISTRIBUTION STORAGE SYSTEM IMPROVEMENT CHARGE (TDSIC)
TDSIC Plan Estimated Annual Revenue Requirement

Line	TDSIC Rate Base Cutoff Rate Period	(B) TDSIC 3 3/31/21 Nov 21-Oct 22	(C) TDSIC 5 3/31/22 Nov 22-Oct 23	(D) TDSIC 7 3/31/23 Nov 23-Oct 24	(E) TDSIC 9 3/31/24 Nov 24-Oct 25	(F) TDSIC 11 3/31/25 Nov 25-Oct 26	(G) TDSIC 13 3/31/26 Nov 26-Oct 27	(H) TDSIC 14 3/31/27 Nov 27-Oct 28	Reference
	Transmission Revenue Requirement Calculation:								
	Return on Rate Base Annual Revenue Requirement:								
1	Rate Base	$ 31,959,484	$ 60,907,755	$ 94,119,045	$ 127,382,719	$ 156,583,423	$ 171,960,164	$ 198,415,324	Attachment CAR-2
2	Pre-Tax WACC	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	IPL Attachment NHC-5 p. 3
3	Allowed Return on TDSIC Utility Plant	$ 2,134,894	$ 4,068,638	$ 6,287,152	$ 8,509,166	$ 10,459,773	$ 11,486,939	$ 13,254,144	Line 1 x Line 2
4	Revenue Conversion	1.23886	1.23886	1.23886	1.23886	1.23886	1.23886	1.23886	IPL Attachment NHC-6
5	Total Return on Rate Base Annual Revenue Requirement	$ 2,644,834	$ 5,040,473	$ 7,788,901	$ 10,541,665	$ 12,958,194	$ 14,230,709	$ 16,420,028	Line 3 x Line 4
	Incremental Expenses Annual Revenue Requirement:								
6	Property Tax Expense - Annualized	$ 257,920	$ 907,148	$ 1,653,252	$ 2,461,950	$ 3,215,065	$ 3,808,136	$ 3,808,136	Attachment CAR-3
7	Depreciation Expense - Annualized	$ 245,658	$ 787,936	$ 1,441,159	$ 2,177,626	$ 2,904,788	$ 3,551,653	$ 4,186,572	Attachment CAR-2
8	Depreciation Expense on Retirements - Credit	$ (28,695)	$ (100,222)	$ (160,406)	$ (183,921)	$ (201,436)	$ (221,956)	$ (241,590)	Attachment CAR-4
9	Amortization Expense - Plan Development Costs	$ 137,259	$ 137,259	$ -	$ -	$ -	$ -	$ -	IPL Attachment NHC-6
10	Total Incremental Expenses before Revenue Conversion	$ 612,142	$ 1,732,121	$ 2,934,005	$ 4,455,655	$ 5,918,417	$ 7,137,832	$ 7,753,117	Line 6 + Line 7 + Line 8 + Line 9
11	Revenue Conversion	1.01995	1.01995	1.01995	1.01995	1.01995	1.01995	1.01995	IPL Attachment NHC-6
12	Total Incremental Expenses Annual Revenue Requirement	$ 624,354	$ 1,766,677	$ 2,992,538	$ 4,544,545	$ 6,036,490	$ 7,280,231	$ 7,907,792	Line 10 x Line 11
13	**Total Annual Revenue Requirement**	$ 3,269,188	$ 6,807,150	$ 10,781,440	$ 15,086,210	$ 18,994,683	$ 21,510,941	$ 24,327,820	Line 5 + Line 12
14	**Revenue Requirement Recoverable in TDSIC Rider (80%)**	$ **2,615,351**	$ **5,445,720**	$ **8,625,152**	$ **12,068,968**	$ **15,195,747**	$ **17,208,753**	$ **19,462,256**	Line 13 x 80%

Line	TDSIC Rate Base Cutoff Rate Period	(B) TDSIC 3 3/31/21 Nov 21-Oct 22	(C) TDSIC 5 3/31/22 Nov 22-Oct 23	(D) TDSIC 7 3/31/23 Nov 23-Oct 24	(E) TDSIC 9 3/31/24 Nov 24-Oct 25	(F) TDSIC 11 3/31/25 Nov 25-Oct 26	(G) TDSIC 13 3/31/26 Nov 26-Oct 27	(G) TDSIC 14 3/31/27 Nov 27-Oct 28	(H) Reference
	Distribution Revenue Requirement Calculation:								
	Return on Rate Base Annual Revenue Requirement:								
15	Rate Base	$ 152,698,568	$ 279,798,342	$ 429,393,259	$ 579,072,934	$ 700,242,713	$ 827,018,320	$ 893,954,448	Attachment CAR-2
16	Pre-Tax WACC	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	IPL Attachment NHC-5 p. 3
17	Allowed Return on TDSIC Utility Plant	$ 10,200,264	$ 18,690,529	$ 28,683,470	$ 38,682,072	$ 46,776,213	$ 55,244,824	$ 59,716,157	Line 15 x Line 16
18	Revenue Conversion	1.23886	1.23886	1.23886	1.23886	1.23886	1.23886	1.23886	IPL Attachment NHC-6
19	Total Return on Rate Base Annual Revenue Requirement	$ 12,636,699	$ 23,154,949	$ 35,534,803	$ 47,921,672	$ 57,949,179	$ 68,440,602	$ 73,979,958	Line 17 x Line 18
	Incremental Expenses Annual Revenue Requirement:								
20	Property Tax Expense - Annualized	$ 1,406,618	$ 4,486,267	$ 7,811,942	$ 11,542,401	$ 14,833,269	$ 17,457,302	$ 17,457,302	Attachment CAR-3
21	Depreciation Expense - Annualized	$ 2,468,877	$ 6,709,853	$ 11,327,281	$ 16,454,700	$ 21,225,220	$ 24,781,988	$ 27,623,552	Attachment CAR-2
22	Depreciation Expense on Retirements - Credit	$ (330,227)	$ (904,382)	$ (1,430,612)	$ (1,964,954)	$ (2,471,394)	$ (2,888,395)	$ (3,188,687)	Attachment CAR-4
23	Amortization Expense - Plan Development Costs	$ 647,080	$ 647,080	$ -	$ -	$ -	$ -	$ -	IPL Attachment NHC-6
24	Total Incremental Expenses before Revenue Conversion	$ 4,192,349	$ 10,938,818	$ 17,708,611	$ 26,032,148	$ 33,587,094	$ 39,350,895	$ 41,892,167	Line 20 + Line 21 + Line 22+ Line 23
25	Revenue Conversion	1.01995	1.01995	1.01995	1.01995	1.01995	1.01995	1.01995	IPL Attachment NHC-6
26	Total Incremental Expenses Annual Revenue Requirement	$ 4,275,986	$ 11,157,048	$ 18,061,898	$ 26,551,489	$ 34,257,157	$ 40,135,945	$ 42,727,916	Line 24 x Line 25
27	**Total Annual Revenue Requirement**	$ 16,912,685	$ 34,311,997	$ 53,596,701	$ 74,473,161	$ 92,206,336	$ 108,576,548	$ 116,707,874	Line 19 + Line 26
28	**Revenue Requirement Recoverable in TDSIC Rider (80%)**	$ **13,530,148**	$ **27,449,597**	$ **42,877,361**	$ **59,578,529**	$ **73,765,069**	$ **86,861,238**	$ **93,366,299**	Line 27 x 80%

Line	TDSIC Rate Base Cutoff Rate Period	(B) TDSIC 3 3/31/21 Nov 21-Oct 22	(C) TDSIC 5 3/31/22 Nov 22-Oct 23	(D) TDSIC 7 3/31/23 Nov 23-Oct 24	(E) TDSIC 9 3/31/24 Nov 24-Oct 25	(F) TDSIC 11 3/31/25 Nov 25-Oct 26	(G) TDSIC 13 3/31/26 Nov 26-Oct 27	(G) TDSIC 14 3/31/27 Nov 27-Oct 28	(H) Reference
	Total TDSIC Revenue Requirement Calculation:								
	Return on Rate Base Annual Revenue Requirement:								
29	Rate Base	$ 184,658,051	$ 340,706,097	$ 523,512,304	$ 706,455,653	$ 856,826,136	$ 998,978,485	$ 1,092,369,771	Attachment CAR-2
30	Pre-Tax WACC	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	IPL Attachment NHC-5 p. 3
31	Allowed Return on TDSIC Utility Plant	$ 12,335,158	$ 22,759,167	$ 34,970,622	$ 47,191,238	$ 57,235,986	$ 66,731,763	$ 72,970,301	Line 29 x Line 30
32	Revenue Conversion	1.23886	1.23886	1.23886	1.23886	1.23886	1.23886	1.23886	IPL Attachment NHC-6
33	Total Return on Rate Base Annual Revenue Requirement	$ 15,281,534	$ 28,195,422	$ 43,323,705	$ 58,463,337	$ 70,907,373	$ 82,671,312	$ 90,399,987	Line 31 x Line 32
	Incremental Expenses Annual Revenue Requirement:								
34	Property Tax Expense - Annualized	$ 1,664,538	$ 5,393,415	$ 9,465,194	$ 14,004,351	$ 18,048,334	$ 21,265,437	$ 21,265,437	Attachment CAR-3
35	Depreciation Expense - Annualized	$ 2,714,535	$ 7,497,789	$ 12,768,441	$ 18,632,327	$ 24,130,008	$ 28,333,641	$ 31,810,124	Attachment CAR-2
36	Depreciation Expense on Retirements - Credit	$ (358,922)	$ (1,004,605)	$ (1,591,018)	$ (2,148,875)	$ (2,672,830)	$ (3,110,351)	$ (3,430,277)	Attachment CAR-4
37	Amortization Expense - Plan Development Costs	$ 784,339	$ 784,339	$ -	$ -	$ -	$ -	$ -	IPL Attachment NHC-6
38	Total Incremental Expenses before Revenue Conversion	$ 4,804,490	$ 12,670,939	$ 20,642,616	$ 30,487,802	$ 39,505,512	$ 46,488,727	$ 49,645,284	Line 6 + Line 7 + Line 8 + Line 9
39	Revenue Conversion	1.01995	1.01995	1.01995	1.01995	1.01995	1.01995	1.01995	IPL Attachment NHC-6
40	Total Incremental Expenses Annual Revenue Requirement	$ 4,900,340	$ 12,923,724	$ 21,054,436	$ 31,096,034	$ 40,293,646	$ 47,416,177	$ 50,635,708	Line 38 x Line 39
41	**Total Annual Revenue Requirement**	$ 20,181,874	$ 41,119,146	$ 64,378,141	$ 89,559,371	$ 111,201,020	$ 130,087,489	$ 141,035,695	Line 33 + Line 40
42	**Revenue Requirement Recoverable in TDSIC Rider (80%)**	$ **16,145,499**	$ **32,895,317**	$ **51,502,513**	$ **71,647,496**	$ **88,960,816**	$ **104,069,991**	$ **112,828,556**	Line 41 x 80%

INDIANAPOLIS POWER & LIGHT COMPANY
TRANSMISSION DISTRIBUTION STORAGE SYSTEM IMPROVEMENT CHARGE (TDSIC)
TDSIC Plan Estimated Retail Rates

		(B)	(C)	(D)	(E)	(F)	(G)	(G)	(H)
	TDSIC	**TDSIC 3**	**TDSIC 5**	**TDSIC 7**	**TDSIC 9**	**TDSIC 11**	**TDSIC 13**	**TDSIC 14**	
	Rate Base Cutoff	**3/31/21**	**3/31/22**	**3/31/23**	**3/31/24**	**3/31/25**	**3/31/26**	**3/31/27**	
Line	**Rate Period**	**Nov 21-Oct 22**	**Nov 22-Oct 23**	**Nov 23-Oct 24**	**Nov 24-Oct 25**	**Nov 25-Oct 26**	**Nov 26-Oct 27**	**Nov 27-Oct 28**	**Reference**
1	**Total Revenue Requirement Rider**	$ 16,145,499	$ 32,895,317	$ 51,502,513	$ 71,647,496	$ 88,960,816	$ 104,069,991	$ 112,828,556	P. 1 Line 41
2	**Rider Revenue Requirement - Transmission**	$ 2,615,351	$ 5,445,720	$ 8,625,152	$ 12,068,968	$ 15,195,747	$ 17,208,753	$ 19,462,256	P. 1 Line 14
3	**Rider Revenue Requirement - Distribution**	$ 13,530,148	$ 27,449,597	$ 42,877,361	$ 59,578,529	$ 73,765,069	$ 86,861,238	$ 93,366,299	P. 1 Line 28
	Allocation Factor - Transmission								
4	Residential	40.50%	40.50%	40.50%	40.50%	40.50%	40.50%	40.50%	CN 45029 Settlement Agreement Att E
5	Small C&I	15.21%	15.21%	15.21%	15.21%	15.21%	15.21%	15.21%	CN 45029 Settlement Agreement Att E
6	Large C&I - Secondary	25.85%	25.85%	25.85%	25.85%	25.85%	25.85%	25.85%	CN 45029 Settlement Agreement Att E
7	Large C&I - Primary	18.04%	18.04%	18.04%	18.04%	18.04%	18.04%	18.04%	CN 45029 Settlement Agreement Att E
8	Lighting	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	CN 45029 Settlement Agreement Att E
	Allocation Factor - Distribution								
10	Residential	57.06%	57.06%	57.06%	57.06%	57.06%	57.06%	57.06%	CN 45029 Settlement Agreement Att E
11	Small C&I	15.84%	15.84%	15.84%	15.84%	15.84%	15.84%	15.84%	CN 45029 Settlement Agreement Att E
12	Large C&I - Secondary	17.95%	17.95%	17.95%	17.95%	17.95%	17.95%	17.95%	CN 45029 Settlement Agreement Att E
13	Large C&I - Primary	8.28%	8.28%	8.28%	8.28%	8.28%	8.28%	8.28%	CN 45029 Settlement Agreement Att E
14	Lighting	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	CN 45029 Settlement Agreement Att E
	Transmission - Revenue Requirement								
15	Residential	$ 1,059,000	$ 2,206,000	$ 3,494,000	$ 4,888,000	$ 6,155,000	$ 6,970,000	$ 7,883,000	Line 2 x Line 4
16	Small C&I	$ 398,000	$ 828,000	$ 1,312,000	$ 1,836,000	$ 2,312,000	$ 2,618,000	$ 2,961,000	Line 2 x Line 5
17	Large C&I - Secondary	$ 676,000	$ 1,408,000	$ 2,230,000	$ 3,120,000	$ 3,928,000	$ 4,448,000	$ 5,031,000	Line 2 x Line 6
18	Large C&I - Primary	$ 472,000	$ 982,000	$ 1,556,000	$ 2,177,000	$ 2,741,000	$ 3,104,000	$ 3,510,000	Line 2 x Line 7
19	Lighting	$ 10,000	$ 22,000	$ 34,000	$ 48,000	$ 61,000	$ 69,000	$ 78,000	Line 2 x Line 8
20	**Total**	$ 2,615,000	$ 5,446,000	$ 8,626,000	$ 12,069,000	$ 15,197,000	$ 17,209,000	$ 19,463,000	Sum Lines 15-19
	Distribution - Revenue Requirement								
21	Residential	$ 7,721,000	$ 15,664,000	$ 24,468,000	$ 33,998,000	$ 42,093,000	$ 49,567,000	$ 53,279,000	Line 3 x Line 10
22	Small C&I	$ 2,143,000	$ 4,348,000	$ 6,792,000	$ 9,437,000	$ 11,685,000	$ 13,759,000	$ 14,789,000	Line 3 x Line 11
23	Large C&I - Secondary	$ 2,429,000	$ 4,929,000	$ 7,699,000	$ 10,697,000	$ 13,244,000	$ 15,596,000	$ 16,764,000	Line 3 x Line 12
24	Large C&I - Primary	$ 1,121,000	$ 2,273,000	$ 3,551,000	$ 4,935,000	$ 6,110,000	$ 7,194,000	$ 7,733,000	Line 3 x Line 13
25	Lighting	$ 116,000	$ 236,000	$ 368,000	$ 511,000	$ 633,000	$ 746,000	$ 802,000	Line 3 x Line 14
26	**Total**	$ 13,530,000	$ 27,450,000	$ 42,878,000	$ 59,578,000	$ 73,765,000	$ 86,862,000	$ 93,367,000	Sum Lines 21-25
	Total Revenue Requirement								
27	Residential	$ 8,780,000	$ 17,870,000	$ 27,962,000	$ 38,886,000	$ 48,248,000	$ 56,537,000	$ 61,162,000	Line 15 + Line 21
28	Small C&I	$ 2,541,000	$ 5,176,000	$ 8,104,000	$ 11,273,000	$ 13,997,000	$ 16,377,000	$ 17,750,000	Line 16 + Line 22
29	Large C&I - Secondary	$ 3,105,000	$ 6,337,000	$ 9,929,000	$ 13,817,000	$ 17,172,000	$ 20,044,000	$ 21,795,000	Line 17 + Line 23
30	Large C&I - Primary	$ 1,593,000	$ 3,255,000	$ 5,107,000	$ 7,112,000	$ 8,851,000	$ 10,298,000	$ 11,243,000	Line 18 + Line 24
31	Lighting	$ 126,000	$ 258,000	$ 402,000	$ 559,000	$ 694,000	$ 815,000	$ 880,000	Line 19 + Line 25
32	**Total**	$ 16,145,000	$ 32,896,000	$ 51,504,000	$ 71,647,000	$ 88,962,000	$ 104,071,000	$ 112,830,000	Sum Lines 27-31

	TDSIC	**TDSIC 3**	**TDSIC 5**	**TDSIC 7**	**TDSIC 9**	**TDSIC 11**	**TDSIC 13**	**TDSIC 14**	
	Rate Base Cutoff	**3/31/21**	**3/31/22**	**3/31/23**	**3/31/24**	**3/31/25**	**3/31/26**	**3/31/27**	
Line	**Rate Period**	**Nov 21-Oct 22**	**Nov 22-Oct 23**	**Nov 23-Oct 24**	**Nov 24-Oct 25**	**Nov 25-Oct 26**	**Nov 26-Oct 27**	**Nov 27-Oct 28**	**Reference**
	Estimated Forecasted Firm Load Volume (MWh)								
33	Residential	5,155,525	5,195,340	5,239,032	5,294,228	5,361,309	5,434,537	5,516,703	IPL Load Forecast
34	Small C&I	1,789,164	1,793,896	1,793,078	1,794,594	1,793,637	1,793,175	1,794,967	IPL Load Forecast
35	Large C&I - Secondary	3,580,334	3,589,004	3,584,686	3,588,756	3,589,762	3,592,276	3,599,307	IPL Load Forecast
36	Large C&I - Primary	2,792,394	2,799,824	2,789,700	2,771,182	2,747,478	2,728,069	2,716,049	IPL Load Forecast
37	Lighting	93,299	92,376	91,452	90,529	89,606	88,682	87,759	IPL Load Forecast
38	**Total**	13,410,716	13,470,439	13,497,948	13,539,289	13,581,791	13,636,739	13,714,785	IPL Load Forecast
	$ per kWh								
39	**Residential**	$ 0.001703	$ 0.003440	$ 0.005337	$ 0.007345	$ 0.008999	$ 0.010403	$ 0.011087	Line 27/Line 33/1,000
40	**Small C&I**	$ 0.001420	$ 0.002885	$ 0.004520	$ 0.006282	$ 0.007804	$ 0.009133	$ 0.009889	Line 28/Line 34/1,000
41	**Large C&I - Secondary**	$ 0.000867	$ 0.001766	$ 0.002770	$ 0.003850	$ 0.004784	$ 0.005580	$ 0.006055	Line 29/Line 35/1,000
42	**Large C&I - Primary**	$ 0.000570	$ 0.001163	$ 0.001831	$ 0.002566	$ 0.003222	$ 0.003775	$ 0.004139	Line 30/Line 36/1,000
43	**Lighting**	$ 0.001350	$ 0.002793	$ 0.004396	$ 0.006175	$ 0.007745	$ 0.009190	$ 0.010027	Line 31/Line 37/1,000

INDIANAPOLIS POWER & LIGHT COMPANY
TRANSMISSION DISTRIBUTION STORAGE SYSTEM IMPROVEMENT CHARGE (TDSIC)
TDSIC Rate Base and Depreciation Expense Estimate Calculation

Line	TDSIC Plan Transmission Assets CapEx Additions (incl AFUDC): FERC Account	(A) Depr Rate	(B) Calendar Year 1 2020	(C) Calendar Year 2 2021	(D) Calendar Year 3 2022	(E) Calendar Year 4 2023	(F) Calendar Year 5 2024	(G) Calendar Year 6 2025	(H) Calendar Year 7 2026	(I)	(J) Total Plan	(K) Reference
1	352.00	2.40%	$ -	$ -	$ -	$ 2,300,385	$ 2,844,940	$ -	$ 2,632,615		$ 7,777,940	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
2	353.00	2.53%	$ 16,542,692	$ 19,582,382	$ 23,096,878	$ 22,073,157	$ 19,302,399	$ 18,615,703	$ 20,407,195		$ 139,620,406	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
3	354.00	1.37%	$ 1,138,320	$ 1,111,147	$ 1,082,432	$ 850,792	$ -	$ -	$ -		$ 4,182,691	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
4	356.00	1.20%	$ 4,765,917	$ 6,881,909	$ 9,502,181	$ 11,200,958	$ 11,497,320	$ 10,679,473	$ 7,601,921		$ 62,129,679	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
5	362.00	1.61%										
6	364.00	2.06%										
7	365.00	2.35%										
8	366.00	2.62%										
9	367.00	2.55%										
10	368.00	0.65%										
11	370.01	19.35%										
12	Total CapEx Additions		$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176	$ 30,641,731		$ 213,710,716	Sum Lines 1-11

Line	Transmission Assets CapEx Additions (incl AFUDC): FERC Account	Depr Rate	TDSIC 1 Thru 3/31/20	TDSIC 3 4/1/20-3/31/21	TDSIC 5 4/1/21-3/31/22	TDSIC 7 4/1/22-3/31/23	TDSIC 9 4/1/23-3/31/24	TDSIC 11 4/1/24-3/31/25	TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Total Plan	Reference
13	352.00	2.40%	$ -	$ -	$ -	$ -	$ 2,300,385	$ 2,844,940	$ -	$ 2,632,615	$ 7,777,940	TDSIC 1: 3/31/2020 Act Balance, Thereafter: Prior Calendar Yr
14	353.00	2.53%	$ -	$ 16,542,692	$ 19,582,382	$ 23,096,878	$ 22,073,157	$ 19,302,399	$ 18,615,703	$ 20,407,195	$ 139,620,406	TDSIC 1: 3/31/2020 Act Balance, Thereafter: Prior Calendar Yr
15	354.00	1.37%	$ -	$ 1,138,320	$ 1,111,147	$ 1,082,432	$ 850,792	$ -	$ -	$ -	$ 4,182,691	TDSIC 1: 3/31/2020 Act Balance, Thereafter: Prior Calendar Yr
16	356.00	1.20%	$ -	$ 4,765,917	$ 6,881,909	$ 9,502,181	$ 11,200,958	$ 11,497,320	$ 10,679,473	$ 7,601,921	$ 62,129,679	TDSIC 1: 3/31/2020 Act Balance, Thereafter: Prior Calendar Yr
17	362.00	1.61%										
18	364.00	2.06%										
19	365.00	2.35%										
20	366.00	2.62%										
21	367.00	2.55%										
22	368.00	0.65%										
23	370.01	19.35%										
24	Total CapEx Additions Placed in Service		$ -	$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176	$ 30,641,731	$ 213,710,716	Sum Lines 13-24
	CWIP Balance 3/31		$ 7,943,370	$ 9,758,213	$ 11,918,982	$ 12,889,940	$ 11,905,948	$ 10,366,782	$ -	$ -		

Line	Transmission Assets 3/31 Utility Plant Balance: FERC Account	Depr Rate	TDSIC 1 3/31/2020	TDSIC 3 3/31/2021	TDSIC 5 3/31/2022	TDSIC 7 3/31/2023	TDSIC 9 3/31/2024	TDSIC 11 3/31/2025	TDSIC 13 3/31/2026	TDSIC 14 3/31/2027	Reference
25	352.00	2.40%	$ -	$ -	$ -	$ -	$ 2,300,385	$ 5,145,325	$ 5,145,325	$ 7,777,940	Line 13 Accumulated
26	353.00	2.53%	$ -	$ 16,542,692	$ 36,125,074	$ 59,221,952	$ 81,295,109	$ 100,597,508	$ 119,213,211	$ 139,620,406	Line 14 Accumulated
27	354.00	1.37%	$ -	$ 1,138,320	$ 2,249,467	$ 3,331,899	$ 4,182,691	$ 4,182,691	$ 4,182,691	$ 4,182,691	Line 15 Accumulated
28	356.00	1.20%	$ -	$ 4,765,917	$ 11,647,826	$ 21,150,007	$ 32,350,965	$ 43,848,285	$ 54,527,758	$ 62,129,679	Line 16 Accumulated
29	362.00	1.61%									
30	364.00	2.06%									
31	365.00	2.35%									
32	366.00	2.62%									
33	367.00	2.55%									
34	368.00	0.65%									
35	370.01	19.35%									
36	Total 3/31 Utility Plant Balance		$ -	$ 22,446,929	$ 50,022,367	$ 83,703,858	$ 120,129,150	$ 153,773,809	$ 183,068,985	$ 213,710,716	Sum Lines 25-36

Line	Transmission Assets Depreciation Expense: FERC Account	Depr Rate	TDSIC 1 Thru 3/31/20	TDSIC 3 4/1/20-3/31/21	TDSIC 5 4/1/21-3/31/22	TDSIC 7 4/1/22-3/31/23	TDSIC 9 4/1/23-3/31/24	TDSIC 11 4/1/24-3/31/25	TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Reference
37	352.00	2.40%	$ -	$ -	$ -	$ -	$ 27,605	$ 89,349	$ 123,488	$ 155,079	(Line 13 x Column A x 50%) + (Prior Line 25 x Column A)
38	353.00	2.53%	$ -	$ 209,265	$ 666,247	$ 1,206,140	$ 1,777,541	$ 2,300,942	$ 2,780,606	$ 3,274,245	(Line 14 x Column A x 50%) + (Prior Line 26 x Column A)
39	354.00	1.37%	$ -	$ 7,797	$ 23,206	$ 38,232	$ 51,475	$ 57,303	$ 57,303	$ 57,303	(Line 15 x Column A x 50%) + (Prior Line 27 x Column A)
40	356.00	1.20%	$ -	$ 28,596	$ 98,482	$ 196,787	$ 321,006	$ 457,196	$ 590,256	$ 699,945	(Line 16 x Column A x 50%) + (Prior Line 28 x Column A)
41	362.00	1.61%									
42	364.00	2.06%									
43	365.00	2.35%									
44	366.00	2.62%									
45	367.00	2.55%									
46	368.00	0.65%									
47	370.01	19.35%									
48	Total Depr Exp - Annualized		$ -	$ 245,658	$ 787,936	$ 1,441,159	$ 2,177,626	$ 2,904,788	$ 3,551,653	$ 4,186,572	

Line	Transmission Assets 3/31 Accumulated Depreciation: FERC Account	Depr Rate	TDSIC 1 3/31/2020	TDSIC 3 3/31/2021	TDSIC 5 3/31/2022	TDSIC 7 3/31/2023	TDSIC 9 3/31/2024	TDSIC 11 3/31/2025	TDSIC 13 3/31/2026	TDSIC 14 3/31/2027	Reference
49	352.00	2.40%	$ -	$ -	$ -	$ -	$ (27,605)	$ (116,953)	$ (240,441)	$ (395,520)	Line 37 Accumulated
50	353.00	2.53%	$ -	$ (209,265)	$ (875,512)	$ (2,081,652)	$ (3,859,193)	$ (6,160,135)	$ (8,940,740)	$ (12,214,985)	Line 38 Accumulated
51	354.00	1.37%	$ -	$ (7,797)	$ (31,004)	$ (69,236)	$ (120,711)	$ (178,014)	$ (235,317)	$ (292,620)	Line 39 Accumulated
52	356.00	1.20%	$ -	$ (28,596)	$ (127,078)	$ (323,865)	$ (644,871)	$ (1,102,066)	$ (1,692,323)	$ (2,392,267)	Line 40 Accumulated
53	362.00	1.61%									
54	364.00	2.06%									
55	365.00	2.35%									
56	366.00	2.62%									
57	367.00	2.55%									
58	368.00	0.65%									
59	370.01	19.35%									
60	Total 3/31 Accum Depr		$ -	$ (245,658)	$ (1,033,594)	$ (2,474,753)	$ (4,652,380)	$ (7,557,168)	$ (11,108,821)	$ (15,295,392)	

Line	Transmission Assets	TDSIC 3	TDSIC 5	TDSIC 7	TDSIC 9	TDSIC 11	TDSIC 13	TDSIC 14
61	3/31 Rate Base	$ 31,959,484	$ 60,907,755	$ 94,119,045	$ 127,382,719	$ 156,583,423	$ 171,960,164	$ 198,415,324

Line	TDSIC Plan Distribution Assets CapEx Additions (incl AFUDC): FERC Account	(A) Depr Rate	(B) Calendar Year 1 2020	(C) Calendar Year 2 2021	(D) Calendar Year 3 2022	(E) Calendar Year 4 2023	(F) Calendar Year 5 2024	(G) Calendar Year 6 2025	(H) Calendar Year 7 2026	(I)	(J) Total Plan	(K) Reference
1	352.00	2.40%										
2	353.00	2.53%										
3	354.00	1.37%										
4	356.00	1.20%										
5	362.00	1.61%	$ 7,026,754	$ 25,672,321	$ 38,188,063	$ 49,360,078	$ 24,862,469	$ 45,555,289	$ 32,554,913		$ 223,219,887	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
6	364.00	2.06%	$ 39,069,911	$ 34,048,557	$ 47,918,689	$ 52,531,374	$ 44,678,960	$ 49,169,935	$ 46,385,522		$ 313,802,948	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
7	365.00	2.35%	$ 28,815,380	$ 27,771,432	$ 26,078,201	$ 27,620,140	$ 25,686,598	$ 27,204,806	$ 26,696,855		$ 189,873,412	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
8	366.00	2.62%	$ 2,250,626	$ 2,346,110	$ 2,405,220	$ 2,690,012	$ 1,809,774	$ 2,715,591	$ 2,769,903		$ 16,987,236	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
9	367.00	2.55%	$ 13,966,103	$ 13,407,560	$ 14,443,018	$ 14,226,294	$ 14,093,313	$ 14,938,612	$ 14,497,783		$ 99,572,683	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
10	368.00	0.65%	$ 12,521,414	$ 12,200,598	$ 15,845,026	$ 17,725,277	$ 15,147,875	$ 16,296,875	$ 15,682,084		$ 105,419,149	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
11	370.01	19.35%	$ 10,735,674	$ 10,950,388	$ 11,169,395	$ 11,392,783	$ 11,620,639	$ -	$ -		$ 55,868,879	TDSIC Plan Filing, IPL Attachment BJB-2 Appendix 8.7
12	Total CapEx Additions		$ 114,385,862	$ 126,396,966	$ 156,047,612	$ 175,545,958	$ 137,899,628	$ 155,881,108	$ 138,587,060		$ 1,004,744,194	

Line	Distribution Assets CapEx Additions (incl AFUDC): FERC Account	Depr Rate	TDSIC 1 Thru 3/31/20	TDSIC 3 4/1/20-3/31/21	TDSIC 5 4/1/21-3/31/22	TDSIC 7 4/1/22-3/31/23	TDSIC 9 4/1/23-3/31/24	TDSIC 11 4/1/24-3/31/25	TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Total Plan	Reference
13	352.00	2.40%										
14	353.00	2.53%										
15	354.00	1.37%										
16	356.00	1.20%										
17	362.00	1.61%	$ -	$ 11,251,524	$ 27,502,588	$ 39,999,824	$ 44,450,455	$ 29,095,162	$ 43,032,278	$ 27,888,056	$ 223,219,887	
18	364.00	2.06%	$ 4,281,117	$ 37,235,492	$ 35,886,510	$ 48,027,574	$ 52,751,284	$ 44,786,565	$ 49,509,809	$ 41,324,597	$ 313,802,948	
19	365.00	2.35%	$ 12,312,934	$ 28,082,071	$ 26,461,278	$ 25,914,617	$ 28,391,801	$ 25,504,493	$ 27,674,067	$ 15,532,151	$ 189,873,412	TDSIC 1: 3/31/2020 Actual Balance,
20	366.00	2.62%	$ 250,490	$ 2,234,596	$ 2,279,093	$ 2,422,942	$ 2,558,378	$ 1,980,163	$ 2,791,032	$ 2,470,542	$ 16,987,236	Thereafter: 75% of Prior Calendar Year + 25% of Current Calendar Year -
21	367.00	2.55%	$ 428,901	$ 13,598,438	$ 13,175,258	$ 14,106,029	$ 14,881,648	$ 13,996,222	$ 15,152,199	$ 14,233,987	$ 99,572,683	Change in CWIP
22	368.00	0.65%	$ 231,365	$ 12,233,709	$ 12,572,860	$ 15,962,723	$ 17,821,051	$ 15,098,668	$ 16,493,422	$ 15,005,351	$ 105,419,149	
23	370.01	19.35%	$ -	$ 10,603,114	$ 10,625,300	$ 10,998,762	$ 12,017,531	$ 8,715,479	$ -	$ 2,908,693	$ 55,868,879	
24	Total CapEx Additions Placed in Service		$ 17,504,807	$ 115,238,944	$ 128,502,887	$ 157,432,471	$ 172,872,149	$ 139,176,753	$ 154,652,808	$ 119,363,376	$ 1,004,744,194	
	CWIP Balance 3/31		$ 20,472,274	$ 22,621,968	$ 27,928,709	$ 31,418,437	$ 24,680,663	$ 27,898,909	$ 24,803,697	$ -		

Line	Distribution Assets 3/31 Utility Plant Balance: FERC Account	Depr Rate	TDSIC 1 3/31/2020	TDSIC 3 3/31/2021	TDSIC 5 3/31/2022	TDSIC 7 3/31/2023	TDSIC 9 3/31/2024	TDSIC 11 3/31/2025	TDSIC 13 3/31/2026	TDSIC 14 3/31/2027	Reference
25	352.00	2.40%									
26	353.00	2.53%									
27	354.00	1.37%									
28	356.00	1.20%									
29	362.00	1.61%	$ -	$ 11,251,524	$ 38,754,112	$ 78,753,936	$ 123,204,391	$ 152,299,553	$ 195,331,831	$ 223,219,887	Line 17 Accumulated
30	364.00	2.06%	$ 4,281,117	$ 41,516,609	$ 77,403,119	$ 125,430,694	$ 178,181,977	$ 222,968,542	$ 272,478,351	$ 313,802,948	Line 18 Accumulated
31	365.00	2.35%	$ 12,312,934	$ 40,395,005	$ 66,856,283	$ 92,770,900	$ 121,162,701	$ 146,667,194	$ 174,341,261	$ 189,873,412	Line 19 Accumulated
32	366.00	2.62%	$ 250,490	$ 2,485,086	$ 4,764,178	$ 7,187,121	$ 9,745,499	$ 11,725,662	$ 14,516,694	$ 16,987,236	Line 20 Accumulated
33	367.00	2.55%	$ 428,901	$ 14,027,340	$ 27,202,598	$ 41,308,626	$ 56,190,274	$ 70,186,497	$ 85,338,696	$ 99,572,683	Line 21 Accumulated
34	368.00	0.65%	$ 231,365	$ 12,465,074	$ 25,037,934	$ 41,000,657	$ 58,821,708	$ 73,920,376	$ 90,413,798	$ 105,419,149	Line 22 Accumulated
35	370.01	19.35%	$ -	$ 10,603,114	$ 21,228,414	$ 32,227,176	$ 44,244,707	$ 52,960,186	$ 52,960,186	$ 55,868,879	Line 23 Accumulated
36	Total 3/31 Utility Plant Balance		$ 17,504,807	$ 132,743,751	$ 261,246,638	$ 418,679,109	$ 591,551,258	$ 730,728,010	$ 885,380,818	$ 1,004,744,194	

Line	Distribution Assets Depreciation Expense: FERC Account	Depr Rate	TDSIC 1 Thru 3/31/20	TDSIC 3 4/1/20-3/31/21	TDSIC 5 4/1/21-3/31/22	TDSIC 7 4/1/22-3/31/23	TDSIC 9 4/1/23-3/31/24	TDSIC 11 4/1/24-3/31/25	TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Reference
37	352.00	2.40%									
38	353.00	2.53%									
39	354.00	1.37%									
40	356.00	1.20%									
41	362.00	1.61%	$ -	$ 90,575	$ 402,545	$ 945,940	$ 1,625,765	$ 2,217,807	$ 2,798,433	$ 3,369,341	(Line 17 x Column A x 50%) + (Prior Line 29 x Column A)
42	364.00	2.06%	$ 44,096	$ 471,717	$ 1,224,873	$ 2,089,188	$ 3,127,211	$ 4,131,850	$ 5,103,103	$ 6,038,697	(Line 18 x Column A x 50%) + (Prior Line 30 x Column A)
43	365.00	2.35%	$ 144,677	$ 619,318	$ 1,260,203	$ 1,875,619	$ 2,513,720	$ 3,147,001	$ 3,771,849	$ 4,279,522	(Line 19 x Column A x 50%) + (Prior Line 31 x Column A)
44	366.00	2.62%	$ 3,281	$ 35,836	$ 94,965	$ 156,562	$ 221,817	$ 281,272	$ 343,775	$ 412,701	(Line 20 x Column A x 50%) + (Prior Line 32 x Column A)
45	367.00	2.55%	$ 5,468	$ 184,317	$ 525,682	$ 873,518	$ 1,243,111	$ 1,611,304	$ 1,982,946	$ 2,357,620	(Line 21 x Column A x 50%) + (Prior Line 33 x Column A)
46	368.00	0.65%	$ 752	$ 41,263	$ 121,885	$ 214,625	$ 324,423	$ 431,412	$ 534,086	$ 636,457	(Line 22 x Column A x 50%) + (Prior Line 34 x Column A)
47	370.01	19.35%	$ -	$ 1,025,851	$ 3,079,700	$ 5,171,828	$ 7,398,655	$ 9,404,573	$ 10,247,796	$ 10,529,212	(Line 23 x Column A x 50%) + (Prior Line 35 x Column A)
48	Total Depr Exp - Annualized		$ 198,274	$ 2,468,877	$ 6,709,853	$ 11,327,281	$ 16,454,700	$ 21,225,220	$ 24,781,988	$ 27,623,552	

Line	Distribution Assets 3/31 Accumulated Depreciation: FERC Account	Depr Rate	TDSIC 1 3/31/2020	TDSIC 3 3/31/2021	TDSIC 5 3/31/2022	TDSIC 7 3/31/2023	TDSIC 9 3/31/2024	TDSIC 11 3/31/2025	TDSIC 13 3/31/2026	TDSIC 14 3/31/2027	Reference
49	352.00	2.40%									
50	353.00	2.53%									
51	354.00	1.37%									
52	356.00	1.20%									
53	362.00	1.61%	$ -	$ (90,575)	$ (493,120)	$ (1,439,060)	$ (3,064,824)	$ (5,282,631)	$ (8,081,064)	$ (11,450,405)	Line 41 Accumulated
54	364.00	2.06%	$ (44,096)	$ (515,812)	$ (1,740,685)	$ (3,829,874)	$ (6,957,084)	$ (11,088,934)	$ (16,192,037)	$ (22,230,735)	Line 42 Accumulated
55	365.00	2.35%	$ (144,677)	$ (763,995)	$ (2,024,198)	$ (3,899,817)	$ (6,413,537)	$ (9,560,538)	$ (13,332,388)	$ (17,611,910)	Line 43 Accumulated
56	366.00	2.62%	$ (3,281)	$ (39,117)	$ (134,083)	$ (290,645)	$ (512,462)	$ (793,734)	$ (1,137,509)	$ (1,550,211)	Line 44 Accumulated
57	367.00	2.55%	$ (5,468)	$ (189,786)	$ (715,467)	$ (1,588,985)	$ (2,832,096)	$ (4,443,400)	$ (6,426,346)	$ (8,783,966)	Line 45 Accumulated
58	368.00	0.65%	$ (752)	$ (42,015)	$ (163,900)	$ (378,526)	$ (702,948)	$ (1,134,360)	$ (1,668,446)	$ (2,304,903)	Line 46 Accumulated
59	370.01	19.35%	$ -	$ (1,025,851)	$ (4,105,552)	$ (9,277,380)	$ (16,676,035)	$ (26,080,608)	$ (36,328,404)	$ (46,857,616)	Line 47 Accumulated
60	Total 3/31 Accum Depr		$ (198,274)	$ (2,667,152)	$ (9,377,005)	$ (20,704,286)	$ (37,158,987)	$ (58,384,206)	$ (83,166,195)	$ (110,789,746)	
	Distribution Assets										
61	3/31 Year Rate Base			$ 152,698,568	$ 279,798,342	$ 429,393,259	$ 579,072,934	$ 700,242,713	$ 827,018,320	$ 893,954,448	

Line	FERC Account	(A) Depr Rate	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Total TDSIC Assets CapEx Additions (incl AFUDC):		Calendar Year 1 2020	Calendar Year 2 2021	Calendar Year 3 2022	Calendar Year 4 2023	Calendar Year 5 2024	Calendar Year 6 2025	Calendar Year 7 2026		Total Plan	Reference
1	352.00	2.40%	$ -	$ -	$ -	$ 2,300,385	$ 2,844,940	$ -	$ 2,632,615		$ 7,777,940	Sum of Same Lines on p. 1 & p. 2
2	353.00	2.53%	$ 16,542,692	$ 19,582,382	$ 23,096,878	$ 22,073,157	$ 19,302,399	$ 18,615,703	$ 20,407,195		$ 139,620,406	Sum of Same Lines on p. 1 & p. 2
3	354.00	1.37%	$ 1,138,320	$ 1,111,147	$ 1,082,432	$ 850,792	$ -	$ -	$ -		$ 4,182,691	Sum of Same Lines on p. 1 & p. 2
4	356.00	1.20%	$ 4,765,917	$ 6,881,909	$ 9,502,181	$ 11,200,958	$ 11,497,320	$ 10,679,473	$ 7,601,921		$ 62,129,679	Sum of Same Lines on p. 1 & p. 2
5	362.00	1.61%	$ 7,026,754	$ 25,672,321	$ 38,188,063	$ 49,360,078	$ 24,862,469	$ 45,555,289	$ 32,554,913		$ 223,219,887	Sum of Same Lines on p. 1 & p. 2
6	364.00	2.06%	$ 39,069,911	$ 34,048,557	$ 47,918,689	$ 52,531,374	$ 44,678,960	$ 49,169,935	$ 46,385,522		$ 313,802,948	Sum of Same Lines on p. 1 & p. 2
7	365.00	2.35%	$ 28,815,380	$ 27,771,432	$ 26,078,201	$ 27,620,140	$ 25,686,598	$ 27,204,806	$ 26,696,855		$ 189,873,412	Sum of Same Lines on p. 1 & p. 2
8	366.00	2.62%	$ 2,250,626	$ 2,346,110	$ 2,405,220	$ 2,690,012	$ 1,809,774	$ 2,715,591	$ 2,769,903		$ 16,987,236	Sum of Same Lines on p. 1 & p. 2
9	367.00	2.55%	$ 13,966,103	$ 13,407,560	$ 14,443,018	$ 14,226,294	$ 14,093,313	$ 14,938,612	$ 14,497,783		$ 99,572,683	Sum of Same Lines on p. 1 & p. 2
10	368.00	0.65%	$ 12,521,414	$ 12,200,598	$ 15,845,026	$ 17,725,277	$ 15,147,875	$ 16,296,875	$ 15,682,084		$ 105,419,149	Sum of Same Lines on p. 1 & p. 2
11	370.01	19.35%	$ 10,735,674	$ 10,950,388	$ 11,169,395	$ 11,392,783	$ 11,620,639	$ -	$ -		$ 55,868,879	Sum of Same Lines on p. 1 & p. 2
12	Total CapEx Additions		$ 136,832,791	$ 153,972,404	$ 189,729,103	$ 211,971,250	$ 171,544,287	$ 185,176,284	$ 169,228,791		$ 1,218,454,910	
	Total TDSIC Assets CapEx Additions (incl AFUDC):	Depr Rate	Plan Year TDSIC 1 Thru 3/31/20	Plan Year TDSIC 3 4/1/20-3/31/21	Plan Year TDSIC 5 4/1/21-3/31/22	Plan Year TDSIC 7 4/1/22-3/31/23	Plan Year TDSIC 9 4/1/23-3/31/24	Plan Year TDSIC 11 4/1/24-3/31/25	Plan Year TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Total Plan	Reference
13	352.00	2.40%	$ -	$ -	$ -	$ -	$ 2,300,385	$ 2,844,940	$ -	$ 2,632,615	$ 7,777,940	Sum of Same Lines on p. 1 & p. 2
14	353.00	2.53%	$ -	$ 16,542,692	$ 19,582,382	$ 23,096,878	$ 22,073,157	$ 19,302,399	$ 18,615,703	$ 20,407,195	$ 139,620,406	Sum of Same Lines on p. 1 & p. 2
15	354.00	1.37%	$ -	$ 1,138,320	$ 1,111,147	$ 1,082,432	$ 850,792	$ -	$ -	$ -	$ 4,182,691	Sum of Same Lines on p. 1 & p. 2
16	356.00	1.20%	$ -	$ 4,765,917	$ 6,881,909	$ 9,502,181	$ 11,200,958	$ 11,497,320	$ 10,679,473	$ 7,601,921	$ 62,129,679	Sum of Same Lines on p. 1 & p. 2
17	362.00	1.61%	$ -	$ 11,251,524	$ 27,502,588	$ 39,999,824	$ 44,450,455	$ 29,095,162	$ 43,032,278	$ 27,888,056	$ 223,219,887	Sum of Same Lines on p. 1 & p. 2
18	364.00	2.06%	$ 4,281,117	$ 37,235,492	$ 35,886,510	$ 48,027,574	$ 52,751,284	$ 44,786,565	$ 49,509,809	$ 41,324,597	$ 313,802,948	Sum of Same Lines on p. 1 & p. 2
19	365.00	2.35%	$ 12,312,934	$ 28,082,071	$ 26,461,278	$ 25,914,617	$ 28,391,801	$ 25,504,493	$ 27,674,067	$ 15,532,151	$ 189,873,412	Sum of Same Lines on p. 1 & p. 2
20	366.00	2.62%	$ 250,490	$ 2,234,596	$ 2,279,093	$ 2,422,942	$ 2,558,378	$ 1,980,163	$ 2,791,032	$ 2,470,542	$ 16,987,236	Sum of Same Lines on p. 1 & p. 2
21	367.00	2.55%	$ 428,901	$ 13,598,438	$ 13,175,258	$ 14,106,029	$ 14,881,648	$ 13,996,222	$ 15,152,199	$ 14,233,987	$ 99,572,683	Sum of Same Lines on p. 1 & p. 2
22	368.00	0.65%	$ 231,365	$ 12,233,709	$ 12,572,860	$ 15,962,723	$ 17,821,051	$ 15,098,668	$ 16,493,422	$ 15,005,351	$ 105,419,149	Sum of Same Lines on p. 1 & p. 2
23	370.01	19.35%	$ -	$ 10,603,114	$ 10,625,300	$ 10,998,762	$ 12,017,531	$ 8,715,479	$ -	$ 2,908,693	$ 55,868,879	Sum of Same Lines on p. 1 & p. 2
24	Total CapEx Additions Placed in Service		$ 17,504,807	$ 137,685,873	$ 156,078,325	$ 191,113,962	$ 209,297,441	$ 172,821,412	$ 183,947,984	$ 150,005,107	$ 1,218,454,910	
	CWIP Balance 3/31		$ 28,415,644	$ 32,380,181	$ 39,847,691	$ 44,308,377	$ 36,586,612	$ 38,265,691	$ 24,803,697	$ -		
	Total TDSIC Assets 3/31 Utility Plant Balance: FERC Account	Depr Rate	TDSIC 1 3/31/2020	TDSIC 3 3/31/2021	TDSIC 5 3/31/2022	TDSIC 7 3/31/2023	TDSIC 9 3/31/2024	TDSIC 11 3/31/2025	TDSIC 13 3/31/2026	TDSIC 14 3/31/2027		Reference
25	352.00	2.40%	$ -	$ -	$ -	$ -	$ 2,300,385	$ 5,145,325	$ 5,145,325	$ 7,777,940		Sum of Same Lines on p. 1 & p. 2
26	353.00	2.53%	$ -	$ 16,542,692	$ 36,125,074	$ 59,221,952	$ 81,295,109	$ 100,597,508	$ 119,213,211	$ 139,620,406		Sum of Same Lines on p. 1 & p. 2
27	354.00	1.37%	$ -	$ 1,138,320	$ 2,249,467	$ 3,331,899	$ 4,182,691	$ 4,182,691	$ 4,182,691	$ 4,182,691		Sum of Same Lines on p. 1 & p. 2
28	356.00	1.20%	$ -	$ 4,765,917	$ 11,647,826	$ 21,150,007	$ 32,350,965	$ 43,848,285	$ 54,527,758	$ 62,129,679		Sum of Same Lines on p. 1 & p. 2
29	362.00	1.61%	$ -	$ 11,251,524	$ 38,754,112	$ 78,753,936	$ 123,204,391	$ 152,299,553	$ 195,331,831	$ 223,219,887		Sum of Same Lines on p. 1 & p. 2
30	364.00	2.06%	$ 4,281,117	$ 41,516,609	$ 77,403,119	$ 125,430,694	$ 178,181,977	$ 222,968,542	$ 272,478,351	$ 313,802,948		Sum of Same Lines on p. 1 & p. 2
31	365.00	2.35%	$ 12,312,934	$ 40,395,005	$ 66,856,283	$ 92,770,900	$ 121,162,701	$ 146,667,194	$ 174,341,261	$ 189,873,412		Sum of Same Lines on p. 1 & p. 2
32	366.00	2.62%	$ 250,490	$ 2,485,086	$ 4,764,178	$ 7,187,121	$ 9,745,499	$ 11,725,662	$ 14,516,694	$ 16,987,236		Sum of Same Lines on p. 1 & p. 2
33	367.00	2.55%	$ 428,901	$ 14,027,340	$ 27,202,598	$ 41,308,626	$ 56,190,274	$ 70,186,497	$ 85,338,696	$ 99,572,683		Sum of Same Lines on p. 1 & p. 2
34	368.00	0.65%	$ 231,365	$ 12,465,074	$ 25,037,934	$ 41,000,657	$ 58,821,708	$ 73,920,376	$ 90,413,798	$ 105,419,149		Sum of Same Lines on p. 1 & p. 2
35	370.01	19.35%	$ -	$ 10,603,114	$ 21,228,414	$ 32,227,176	$ 44,244,707	$ 52,960,186	$ 52,960,186	$ 55,868,879		Sum of Same Lines on p. 1 & p. 2
36	Total End of Year Utility Plant Balance		$ 17,504,807	$ 155,190,680	$ 311,269,005	$ 502,382,967	$ 711,680,408	$ 884,501,819	$ 1,068,449,803	$ 1,218,454,910		
	Total TDSIC Assets Depreciation Expense: FERC Account	Depr Rate	TDSIC 1 Thru 3/31/20	TDSIC 3 4/1/20-3/31/21	TDSIC 5 4/1/21-3/31/22	TDSIC 7 4/1/22-3/31/23	TDSIC 9 4/1/23-3/31/24	TDSIC 11 4/1/24-3/31/25	TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27		Reference
37	352.00	2.40%	$ -	$ -	$ -	$ -	$ 27,605	$ 89,349	$ 123,488	$ 155,079		Sum of Same Lines on p. 1 & p. 2
38	353.00	2.53%	$ -	$ 209,265	$ 666,247	$ 1,206,140	$ 1,777,541	$ 2,300,942	$ 2,780,606	$ 3,274,245		Sum of Same Lines on p. 1 & p. 2
39	354.00	1.37%	$ -	$ 7,797	$ 23,206	$ 38,232	$ 51,475	$ 57,303	$ 57,303	$ 57,303		Sum of Same Lines on p. 1 & p. 2
40	356.00	1.20%	$ -	$ 28,596	$ 98,482	$ 196,787	$ 321,006	$ 457,196	$ 590,256	$ 699,945		Sum of Same Lines on p. 1 & p. 2
41	362.00	1.61%	$ -	$ 90,575	$ 402,545	$ 945,940	$ 1,625,765	$ 2,217,807	$ 2,798,433	$ 3,369,341		Sum of Same Lines on p. 1 & p. 2
42	364.00	2.06%	$ 44,096	$ 471,717	$ 1,224,873	$ 2,089,188	$ 3,127,211	$ 4,131,850	$ 5,103,103	$ 6,038,697		Sum of Same Lines on p. 1 & p. 2
43	365.00	2.35%	$ 144,677	$ 619,318	$ 1,260,203	$ 1,875,619	$ 2,513,720	$ 3,147,001	$ 3,771,849	$ 4,279,522		Sum of Same Lines on p. 1 & p. 2
44	366.00	2.62%	$ 3,281	$ 35,836	$ 94,965	$ 156,562	$ 221,817	$ 281,272	$ 343,775	$ 412,701		Sum of Same Lines on p. 1 & p. 2
45	367.00	2.55%	$ 5,468	$ 184,317	$ 525,682	$ 873,518	$ 1,243,111	$ 1,611,304	$ 1,982,946	$ 2,357,620		Sum of Same Lines on p. 1 & p. 2
46	368.00	0.65%	$ 752	$ 41,263	$ 121,885	$ 214,625	$ 324,423	$ 431,412	$ 534,086	$ 636,457		Sum of Same Lines on p. 1 & p. 2
47	370.01	19.35%	$ -	$ 1,025,851	$ 3,079,700	$ 5,171,828	$ 7,398,655	$ 9,404,573	$ 10,247,796	$ 10,529,212		Sum of Same Lines on p. 1 & p. 2
48	Total Depr Exp - Annualized		$ 198,274	$ 2,714,535	$ 7,497,789	$ 12,768,441	$ 18,632,327	$ 24,130,008	$ 28,333,641	$ 31,810,124		
	Total TDSIC Assets 3/31 Accumulated Depreciation: FERC Account	Depr Rate	TDSIC 1 3/31/2020	TDSIC 3 3/31/2021	TDSIC 5 3/31/2022	TDSIC 7 3/31/2023	TDSIC 9 3/31/2024	TDSIC 11 3/31/2025	TDSIC 13 3/31/2026	TDSIC 14 3/31/2027		Reference
49	352.00	2.40%	$ -	$ -	$ -	$ -	$ (27,605)	$ (116,953)	$ (240,441)	$ (395,520)		Sum of Same Lines on p. 1 & p. 2
50	353.00	2.53%	$ -	$ (209,265)	$ (875,512)	$ (2,081,652)	$ (3,859,193)	$ (6,160,135)	$ (8,940,740)	$ (12,214,985)		Sum of Same Lines on p. 1 & p. 2
51	354.00	1.37%	$ -	$ (7,797)	$ (31,004)	$ (69,236)	$ (120,711)	$ (178,014)	$ (235,317)	$ (292,620)		Sum of Same Lines on p. 1 & p. 2
52	356.00	1.20%	$ -	$ (28,596)	$ (127,078)	$ (323,865)	$ (644,871)	$ (1,102,066)	$ (1,692,323)	$ (2,392,267)		Sum of Same Lines on p. 1 & p. 2
53	362.00	1.61%	$ -	$ (90,575)	$ (493,120)	$ (1,439,060)	$ (3,064,824)	$ (5,282,631)	$ (8,081,064)	$ (11,450,405)		Sum of Same Lines on p. 1 & p. 2
54	364.00	2.06%	$ (44,096)	$ (515,812)	$ (1,740,685)	$ (3,829,874)	$ (6,957,084)	$ (11,088,934)	$ (16,192,037)	$ (22,230,735)		Sum of Same Lines on p. 1 & p. 2
55	365.00	2.35%	$ (144,677)	$ (763,995)	$ (2,024,198)	$ (3,899,817)	$ (6,413,537)	$ (9,560,538)	$ (13,332,388)	$ (17,611,910)		Sum of Same Lines on p. 1 & p. 2
56	366.00	2.62%	$ (3,281)	$ (39,117)	$ (134,083)	$ (290,645)	$ (512,462)	$ (793,734)	$ (1,137,509)	$ (1,550,211)		Sum of Same Lines on p. 1 & p. 2
57	367.00	2.55%	$ (5,468)	$ (189,786)	$ (715,467)	$ (1,588,985)	$ (2,832,096)	$ (4,443,400)	$ (6,426,346)	$ (8,783,966)		Sum of Same Lines on p. 1 & p. 2
58	368.00	0.65%	$ (752)	$ (42,015)	$ (163,900)	$ (378,526)	$ (702,948)	$ (1,134,360)	$ (1,668,446)	$ (2,304,903)		Sum of Same Lines on p. 1 & p. 2
59	370.01	19.35%	$ -	$ (1,025,851)	$ (4,105,552)	$ (9,277,380)	$ (16,676,035)	$ (26,080,608)	$ (36,328,404)	$ (46,857,616)		Sum of Same Lines on p. 1 & p. 2
60	Total 3/31 Accum Depr		$ (198,274)	$ (2,912,810)	$ (10,410,599)	$ (23,179,040)	$ (41,811,366)	$ (65,941,375)	$ (94,275,015)	$ (126,085,139)		
	Total TDSIC Assets											
61	3/31 Rate Base			$ 184,658,051	$ 340,706,097	$ 523,512,304	$ 706,455,653	$ 856,826,136	$ 998,978,485	$ 1,092,369,771		Sum of Same Lines on p. 1 & p. 2

INDIANAPOLIS POWER & LIGHT COMPANY
TRANSMISSION DISTRIBUTION STORAGE SYSTEM IMPROVEMENT CHARGE (TDSIC)
Property Tax Expense Estimate Calculation

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Year 2	Year 3	Year 4	Year 5	Year 6	Year 7		
Line	Description		2021	2022	2023	2024	2025	2026		Reference
	Assessment Date	12/31/19	12/31/20	12/31/21	12/31/22	12/31/23	12/31/24	12/31/25		
	Transmission Assets									
	Property Tax Calculation - One Year in Arrears:									
1	Accumulated Additions		$ 22,446,929	$ 50,022,367	$ 83,703,858	$ 120,129,150	$ 153,773,809	$ 183,068,985		TDSIC Plan Filing Attachment CAR-3
2	less Accumulated Tax Depreciation		$ 953,591	$ 3,929,938	$ 9,263,661	$ 17,125,014	$ 27,296,330	$ 39,309,822		TDSIC Plan Filing Attachment CAR-3
3	Accumulated Additions Net of Tax Depr		$ 21,493,338	$ 46,092,429	$ 74,440,197	$ 103,004,136	$ 126,477,479	$ 143,759,163		Line 1 - Line 2
4	Current Year Additions		$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176		TDSIC Plan Filing Attachment CAR-3
5	less Tax Depreciation on CY Spend		$ 953,591	$ 1,151,833	$ 1,461,825	$ 1,526,714	$ 1,463,581	$ 1,259,657		TDSIC Plan Filing Attachment CAR-3
6	Current Year Additions Net of Tax Depr		$ 21,493,338	$ 26,423,605	$ 32,219,666	$ 34,898,578	$ 32,181,078	$ 28,035,519		Line 4 - Line 5
7	Credit Amount		60.0%	60.0%	60.0%	60.0%	60.0%	60.0%		
8	60% Credit for Gross Additions		$ 12,896,003	$ 15,854,163	$ 19,331,799	$ 20,939,147	$ 19,308,647	$ 16,821,311		Line 6 x Line 7
9	Net Assessed Value		$ 8,597,335	$ 30,238,267	$ 55,108,397	$ 82,064,990	$ 107,168,832	$ 126,937,851		Line 3 - Line 8
10	Property Tax Rate		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%		Property Tax Rate
11	Property Tax Expense - Annualized		$ 257,920	$ 907,148	$ 1,653,252	$ 2,461,950	$ 3,215,065	$ 3,808,136		Line 9 x Line 10
		TDSIC 1	TDSIC 3	TOSIC 5	TDSIC 7	TDSIC 9	TDSIC 11	TDSIC 13	TDSIC 14	
		11/1/20-10/31/21	11/1/21-10/31/22	11/1/22-10/31/23	11/1/23-10/31/24	11/1/24-10/31/25	11/1/25-10/31/26	11/1/26-10/31/27	11/1/27-10/31/28	
12		$ -	$ 257,920	$ 907,148	$ 1,653,252	$ 2,461,950	$ 3,215,065	$ 3,808,136	$ 3,808,136	Calendar Year
			Year 2	Year 3	Year 4	Year 5	Year 6	Year 7		
Line	Description		2021	2022	2023	2024	2025	2026		Reference
	Assessment Date	12/31/19	12/31/20	12/31/21	12/31/22	12/31/23	12/31/24	12/31/25		
	Distribution Assets									
	Property Tax Calculation - One Year in Arrears:									
13	Accumulated Additions		$ 114,385,862	$ 240,782,828	$ 396,830,440	$ 572,376,398	$ 710,276,026	$ 866,157,134		TDSIC Plan Filing Attachment CAR-3
14	less Accumulated Tax Depreciation		$ 5,709,531	$ 22,526,290	$ 50,613,292	$ 90,568,943	$ 140,535,209	$ 197,829,920		TDSIC Plan Filing Attachment CAR-3
15	Accumulated Additions Net of Tax Depr		$ 108,676,331	$ 218,256,539	$ 346,217,149	$ 481,807,456	$ 569,740,817	$ 668,327,214		Line 13 - Line 14
16	Current Year Additions		$ 114,385,862	$ 126,396,966	$ 156,047,612	$ 175,545,958	$ 137,899,628	$ 155,881,108		TDSIC Plan Filing Attachment CAR-3
17	less Tax Depreciation on CY Spend		$ 5,709,531	$ 6,178,592	$ 7,321,232	$ 8,083,486	$ 6,707,523	$ 6,157,963		TDSIC Plan Filing Attachment CAR-3
18	Current Year Additions Net of Tax Depr		$ 108,676,331	$ 120,218,374	$ 148,726,380	$ 167,462,472	$ 131,192,105	$ 149,723,145		Line 16 - Line 17
19	Credit Amount		60.0%	60.0%	60.0%	60.0%	60.0%	60.0%		
20	60% Credit for Gross Additions		$ 65,205,799	$ 72,131,024	$ 89,235,828	$ 100,477,483	$ 78,715,263	$ 89,833,887		Line 18 x Line 19
21	Net Assessed Value		$ 43,470,532	$ 146,125,514	$ 256,981,320	$ 381,329,972	$ 491,025,554	$ 578,493,327		Line 15 - Line 20
22	Property Tax Rate		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%		Property Tax Rate
23	Property Tax Expense - Annualized		$ 1,304,116	$ 4,383,765	$ 7,709,440	$ 11,439,899	$ 14,730,767	$ 17,354,800		Line 21 x Line 22
		TDSIC 1	TDSIC 3	TDSIC 5	TDSIC 7	TDSIC 9	TDSIC 11	TDSIC 13	TDSIC 14	
		11/1/20-10/31/21	11/1/21-10/31/22	11/1/22-10/31/23	11/1/23-10/31/24	11/1/24-10/31/25	11/1/25-10/31/26	11/1/26-10/31/27	11/1/27-10/31/28	
24		$ 102,502	$ 1,406,618	$ 4,486,267	$ 7,811,942	$ 11,542,401	$ 14,833,269	$ 17,457,302	$ 17,457,302	Calendar Year + TDSIC 1 Amount
			Year 2	Year 3	Year 4	Year 5	Year 6	Year 7		
Line	Description		2021	2022	2023	2024	2025	2026		Reference
	Total TDSIC Assets									
	Property Tax Calculation - One Year in Arrears:									
25	Accumulated Additions		$ 136,832,791	$ 290,805,195	$ 480,534,298	$ 692,505,548	$ 864,049,835	$ 1,049,226,119		TDSIC Plan Filing Attachment CAR-3
26	less Accumulated Tax Depreciation		$ 6,663,122	$ 26,456,227	$ 59,876,953	$ 107,693,956	$ 167,831,539	$ 237,139,742		TDSIC Plan Filing Attachment CAR-3
27	Accumulated Additions Net of Tax Depr		$ 130,169,669	$ 264,348,968	$ 420,657,345	$ 584,811,592	$ 696,218,296	$ 812,086,377		Line 25 - Line 26
28	Current Year Additions		$ 136,832,791	$ 153,972,404	$ 189,729,103	$ 211,971,250	$ 171,544,287	$ 185,176,284		TDSIC Plan Filing Attachment CAR-3
29	less Tax Depreciation on CY Spend		$ 6,663,122	$ 7,330,426	$ 8,783,057	$ 9,610,200	$ 8,171,104	$ 7,417,620		TDSIC Plan Filing Attachment CAR-3
30	Current Year Additions Net of Tax Depr		$ 130,169,669	$ 146,641,979	$ 180,946,046	$ 202,361,050	$ 163,373,183	$ 177,758,664		Line 28 - Line 29
31	Credit Amount		60.0%	60.0%	60.0%	60.0%	60.0%	60.0%		
32	60% Credit for Gross Additions		$ 78,101,802	$ 87,985,187	$ 108,567,628	$ 121,416,630	$ 98,023,910	$ 106,655,198		Line 30 x Line 31
33	Net Assessed Value		$ 52,067,868	$ 176,363,781	$ 312,089,718	$ 463,394,962	$ 598,194,386	$ 705,431,179		Line 27 - Line 32
34	Property Tax Rate		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%		Property Tax Rate
35	Property Tax Expense - Annualized		$ 1,562,036	$ 5,290,913	$ 9,362,692	$ 13,901,849	$ 17,945,832	$ 21,162,935		Line 33 x Line 34
		TDSIC 1	TDSIC 3	TDSIC 5	TDSIC 7	TDSIC 9	TDSIC 11	TDSIC 13	TDSIC 14	
		11/1/20-10/31/21	11/1/21-10/31/22	11/1/22-10/31/23	11/1/23-10/31/24	11/1/24-10/31/25	11/1/25-10/31/26	11/1/26-10/31/27	11/1/27-10/31/28	
36		$ 102,502	$ 1,664,538	$ 5,393,415	$ 9,465,194	$ 14,004,351	$ 18,048,334	$ 21,265,437	$ 21,265,437	Line 12 + Line 24

INDIANAPOLIS POWER & LIGHT COMPANY
TRANSMISSION DISTRIBUTION STORAGE SYSTEM IMPROVEMENT CHARGE (TDSIC)
TDSIC Retirements Depreciation Expense Estimate Calculation

Line	TDSIC Plan Projected Retirements FERC Account	(A) Depr Rate	(B) Calendar Year 1 2020	(C) Calendar Year 2 2021	(D) Calendar Year 3 2022	(E) Calendar Year 4 2023	(F) Calendar Year 5 2024	(G) Calendar Year 6 2025	(H) Calendar Year 7 2026	(I)	(J) Total Plan	(K) Reference
1	352.00	2.40%	-	-	-	-	-	-	-		-	IPL Fixed Assets Accounting Estimate
2	353.00	2.53%	1,231,941	3,954,309	1,644,555	341,603	916,047	620,044	1,048,727		9,757,226	IPL Fixed Assets Accounting Estimate
3	354.00	1.37%	-	-	-	-	-	-	-		-	IPL Fixed Assets Accounting Estimate
4	356.00	1.20%	51,662	83,569	52,677	60,877	61,263	55,789	38,933		404,770	IPL Fixed Assets Accounting Estimate
5	362.00	1.61%	1,146,021	2,654,604	1,409,638	1,053,622	1,320,470	1,153,473	537,942		9,275,770	IPL Fixed Assets Accounting Estimate
6	364.00	2.06%	7,415,217	5,720,125	7,560,967	7,374,609	7,114,649	6,443,123	5,789,027		47,417,717	IPL Fixed Assets Accounting Estimate
7	365.00	2.35%	1,125,231	863,094	1,305,598	1,418,379	1,168,250	1,258,873	1,134,708		8,274,133	IPL Fixed Assets Accounting Estimate
8	366.00	2.62%	57,632	57,632	57,632	100,856	86,448	100,856	100,856		561,912	IPL Fixed Assets Accounting Estimate
9	367.00	2.55%	6,232,198	6,342,870	6,389,583	6,351,738	6,310,125	6,353,246	6,351,297		44,331,057	IPL Fixed Assets Accounting Estimate
10	368.00	0.65%	1,584,238	1,567,558	2,097,123	2,232,092	1,932,754	2,041,205	1,892,610		13,347,580	IPL Fixed Assets Accounting Estimate
11	370.00	3.90%	3,899,910	3,899,910	3,899,910	3,899,910	3,899,910	-	-		19,499,550	IPL Fixed Assets Accounting Estimate
12	**Total Estimated Projected Retirments**		22,744,050	25,143,671	24,417,683	22,833,686	22,809,916	18,026,609	16,894,100		152,869,715	

Line	TDSIC Plan Projected Retirments FERC Account	Depr Rate	TDSIC 1 Thru 3/31/20	TDSIC 3 4/1/20-3/31/21	TDSIC 5 4/1/21-3/31/22	TDSIC 7 4/1/22-3/31/23	TDSIC 9 4/1/23-3/31/24	TDSIC 11 4/1/24-3/31/25	TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Total Plan	Reference
13	352.00	2.40%	-	-	-	-	-	-	-	-	-	
14	353.00	2.53%	13,461	2,207,057	3,376,870	1,318,817	485,214	842,046	727,215	786,545	9,757,226	
15	354.00	1.37%	-	-	-	-	-	-	-	-	-	
16	356.00	1.20%	-	72,554	75,846	54,727	60,974	59,895	51,575	29,200	404,770	
17	362.00	1.61%	-	1,809,672	2,343,363	1,320,634	1,120,334	1,278,721	999,590	403,457	9,275,770	TDSIC 1: 3/31/2020 Actual Balance,
18	364.00	2.06%	225,925	8,619,323	6,180,336	7,514,378	7,309,619	6,946,768	6,279,599	4,341,770	47,417,717	Thereafter: 75% of Prior Calendar Year + 25% of Current
19	365.00	2.35%	252,191	1,088,813	973,720	1,333,793	1,355,847	1,190,906	1,227,832	851,031	8,274,133	Calendar Year
20	366.00	2.62%	2,184	69,856	57,632	68,438	97,254	90,050	100,856	75,642	561,912	
21	367.00	2.55%	8,877	7,809,039	6,354,548	6,380,122	6,341,335	6,320,905	6,352,759	4,763,473	44,331,057	
22	368.00	0.65%	387,462	1,588,665	1,699,949	2,130,865	2,157,258	1,959,867	2,004,056	1,419,458	13,347,580	
23	370.00	3.90%	-	4,874,888	3,899,910	3,899,910	3,899,910	2,924,933	-	-	19,499,550	
24	**Total CapEx Additions Placed In Service**		890,101	28,139,866	24,962,174	24,021,684	22,827,744	21,614,089	17,743,482	12,670,575	152,869,715	

Line	Retired Assets 3/31 Cumulative Retired Plant Balance: FERC Account	Depr Rate	TDSIC 1 3/31/2020	TDSIC 3 3/31/2021	TDSIC 5 3/31/2022	TDSIC 7 3/31/2023	TDSIC 9 3/31/2024	TDSIC 11 3/31/2025	TDSIC 13 3/31/2026	TDSIC 14 3/31/2027	Reference
25	352.00	2.40%	-	-	-	-	-	-	-	-	Line 13 Accumulated
26	353.00	2.53%	13,461	2,220,518	5,597,389	6,916,205	7,401,419	8,243,466	8,970,681	9,757,226	Line 14 Accumulated
27	354.00	1.37%	-	-	-	-	-	-	-	-	Line 15 Accumulated
28	356.00	1.20%	-	72,554	148,400	203,127	264,101	323,995	375,570	404,770	Line 16 Accumulated
29	362.00	1.61%	-	1,809,672	4,153,035	5,473,669	6,594,003	7,872,724	8,872,314	9,275,770	Line 17 Accumulated
30	364.00	2.06%	225,925	8,845,248	15,025,584	22,539,961	29,849,580	36,796,348	43,075,947	47,417,717	Line 18 Accumulated
31	365.00	2.35%	252,191	1,341,005	2,314,725	3,648,518	5,004,365	6,195,270	7,423,102	8,274,133	Line 19 Accumulated
32	366.00	2.62%	2,184	72,040	129,672	198,110	295,364	385,414	486,270	561,912	Line 20 Accumulated
33	367.00	2.55%	8,877	7,817,916	14,172,464	20,552,586	26,893,920	33,214,826	39,567,584	44,331,057	Line 21 Accumulated
34	368.00	0.65%	387,462	1,976,128	3,676,077	5,806,942	7,964,200	9,924,066	11,928,123	13,347,580	Line 22 Accumulated
35	370.00	3.90%	-	4,874,888	8,774,798	12,674,708	16,574,618	19,499,550	19,499,550	19,499,550	Line 23 Accumulated
36	**Total 3/31 Utility Plant Balance**		890,101	29,029,968	53,992,142	78,013,826	100,841,569	122,455,659	140,199,140	152,869,715	

Line	Retired Assets Depreciation Expense: FERC Account	Depr Rate	TDSIC 1 Thru 3/31/20	TDSIC 3 4/1/20-3/31/21	TDSIC 5 4/1/21-3/31/22	TDSIC 7 4/1/22-3/31/23	TDSIC 9 4/1/23-3/31/24	TDSIC 11 4/1/24-3/31/25	TDSIC 13 4/1/25-3/31/26	TDSIC 14 4/1/26-3/31/27	Reference
37	352.00	2.40%		-	-	-	-	-	-	-	(Line 13 x Col A x 50%) + (Prior Line 25 x Col A)
38	353.00	2.53%		28,260	98,897	158,297	181,118	197,908	217,759	236,908	(Line 14 x Col A x 50%) + (Prior Line 26 x Col A)
39	354.00	1.37%		-	-	-	-	-	-	-	(Line 15 x Col A x 50%) + (Prior Line 27 x Col A)
40	356.00	1.20%		435	1,326	2,109	2,803	3,529	4,197	4,682	(Line 16 x Col A x 50%) + (Prior Line 28 x Col A)
41	362.00	1.61%		14,568	48,000	77,495	97,145	116,457	134,798	146,092	(Line 17 x Col A x 50%) + (Prior Line 29 x Col A)
42	364.00	2.06%		93,433	245,870	386,925	539,612	686,453	822,685	932,085	(Line 18 x Col A x 50%) + (Prior Line 30 x Col A)
43	365.00	2.35%		18,720	42,955	70,068	101,671	131,596	160,016	184,443	(Line 19 x Col A x 50%) + (Prior Line 31 x Col A)
44	366.00	2.62%		972	2,642	4,294	6,465	8,918	11,419	13,731	(Line 20 x Col A x 50%) + (Prior Line 32 x Col A)
45	367.00	2.55%		99,792	280,377	442,744	604,943	766,387	927,976	1,069,708	(Line 21 x Col A x 50%) + (Prior Line 33 x Col A)
46	368.00	0.65%		7,682	18,370	30,820	44,756	58,137	71,020	82,146	(Line 22 x Col A x 50%) + (Prior Line 34 x Col A)
47	370.00	3.90%		95,060	266,169	418,265	570,362	703,446	760,482	760,482	(Line 23 x Col A x 50%) + (Prior Line 35 x Col A)
48	**Total Depr Exp - Annualized**		14,320	358,922	1,004,605	1,591,018	2,148,875	2,672,830	3,110,351	3,430,277	

			TDSIC 1	TDSIC 3	TDSIC 5	TDSIC 7	TDSIC 9	TDSIC 11	TDSIC 13	TDSIC 14	Reference
	Total Depr Exp - Annualized - Transmission		-	28,695	100,222	160,406	183,921	201,436	221,956	241,590	Sum of Lines 37 - 40
	Total Depr Exp - Annualized - Distribution		14,320	330,227	904,382	1,430,612	1,964,954	2,471,394	2,888,395	3,188,687	Sum of Lines 41 - 47

REGULATORY MECHANISMS

ELECTRIC GROUP

		Type of Adjustment Clause										
				Decoupling				New Capital				
	Holding Company	Elec. Fuel/ Purch. Pwr	Conserv. Program Expense	Full	Partial	Renew-ables Expense	Environ-mental Compliance	Gener-ation Capacity	Generic Infra-structure	Trans-mission Expense	Other	Future Test Year
1	Algonquin Pwr & Util	√	- -	- -	√	- -	√	- -	√	√	Taxes, franchise fees; Renewables mechanism available	P
2	ALLETE	√	√	- -	- -	√	√	- -	- -	√		C
3	Alliant Energy	√	√	- -	- -	√	√	√	√	√	Taxes, franchise fees	C
4	Ameren Corp.	√	√	- -	√	√	√	- -	√	√	Taxes, franchise fees, bad debts	O,P
5	American Elec Pwr	√	√	- -	√	√	√	√	√	√	Taxes, franchise fees, bad debts, vegetation management costs	C,O,P
6	AVANGRID, Inc.	D	√	√	- -	√	- -	D	- -	- -	Storm costs	C
7	Black Hills Corp.	√	√	- -	√	√	√	√	√	√		O
8	CenterPoint Energy	D	√	- -	- -	- -	- -	D	√	√	Franchise fees	- -
9	CMS Energy Corp.	√	√	- -	- -	√	- -	- -	- -	√		C
10	Consolidated Edison	D	- -	√	- -	√	- -	- -	- -	- -		C
11	Dominion Energy	√	√	- -	- -	√	√	√	- -	√	Taxes, franchise fees	- -
12	DTE Energy Co.	√	√	- -	- -	√	- -	- -	- -	√		C
13	Duke Energy Corp.	√	√	- -	√	√	√	√	√	√	Taxes, franchise fees, bad debts, storm costs	C,O,P
14	Edison International	√	- -	√	- -	- -	- -	- -	- -	- -		C
15	El Paso Electric Co.	√	√	- -	- -	- -	- -	√	- -	- -	Military base discounts	- -
16	Entergy Corp.	√	√	- -	√	- -	√	√	√	√	Taxes, franchise fees, storm costs	O,P
17	Exelon Corp.	D	√	√	√	√	√	D	√	√	Taxes, franchise fees, bad debts, nuclear decomm., societal benefits	O,P
18	IDACORP, Inc.	√	√	√	- -	- -	- -	- -	- -	- -		P
19	NextEra Energy, Inc.	√	√	- -	- -	- -	√	√	- -	- -	Taxes, franchise fees	C
20	NorthWestern Corp.	√	√	- -	- -	- -	- -	- -	- -	- -	Purchased power contracts	- -
21	OGE Energy Corp.	√	√	- -	√	√	√	- -	√	√	Taxes, franchise fees, storm costs, security/safety related costs	- -
22	Otter Tail Corp.	√	√	- -	- -	√	√	- -	- -	√		C
23	PG&E Corp.	√	- -	√	- -	- -	- -	- -	- -	- -		C
24	Pinnacle West Capital	√	√	- -	√	√	√	√	- -	√	Franchise fees	- -
25	Portland General Elec.	√	√	- -	√	√	- -	- -	- -	- -		C
26	PPL Corp.	√	√	- -	√	√	√	- -	√	√	Taxes, franchise fees, universal service program costs	O
27	Pub Sv Enterprise Grp.	D	√	- -	- -	√	√	D	√	- -	Taxes, franchise fees, societal benefits	P
28	Southern Company	√	√	- -	√	- -	√	√	- -	- -	Taxes, franchise fees, storm costs	C,O
29	Vectren Corp.	√	√	- -	√	- -	- -	- -	√	√		- -
30	WEC Energy Group	√	- -	- -	- -	- -	- -	- -	- -	- -	Taxes, franchise fees	C
31	Xcel Energy Inc.	√	√	√	- -	√	√	√	√	√	Taxes, franchise fees, university discounts	C

Sources:

IPL Witness AMM Attachment 3, pages 2-5, contain operating company data that are aggregated into the parent company data on this page.

Notes:

D - Delivery-only utility.

C - Fully-forecasted test years commonly used in the state listed for this operating company.

O - Fully-forecasted test years occasionally used in the state listed for this operating company.

P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.

REGULATORY MECHANISMS

ELECTRIC OPERATING COS.

Holding Company/ Operating Company	Type of Svc	State	Type of Adjustment Clause (a): Elec. Fuel/ Gas/ Purch. Pwr	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renew-ables Expense	Environ-mental Compliance	New Capital: Gener-ation Capacity	New Capital: Generic Infra-structure	Trans-mission Expense	Other	Future Test Year (b)
ALGONQUIN PWR. & UTIL.													
Empire District Electric	Elec.	MO	√	--	--	--	--	√	--	--	√	√	P
Liberty Utilities	Elec.	NH	D	--	--	√	--	--	--	√	--	--	--
ALLETE													
Minnesota Pwr	Elec.	MN	√	√	--	--	√	√	--	--	√	--	C
ALLIANT ENERGY													
Interstate P&L	Elec.	IA	√	√	--	--	√	√	--	--	√	√	--
Wisconsin P&L	Elec.	WI	√	--	--	--	--	--	LIR	LIR	--	√	C
AMEREN													
Ameren Illinois	Elec.	IL	D	√	--	--	√	√	D	--	√	√	O
Union Electric	Elec.	MO	√	√	--	√	--	√	--	√	√	√	P
AMERICAN ELEC PWR													
AEP Texas Central	Elec.	TX	D	√	--	--	--	--	D	√	√	--	--
AEP Texas North	Elec.	TX	D	√	--	--	--	--	D	√	√	--	--
Appalachian Pwr	Elec.	VA	√	√	--	--	√	--	√	--	√	√	--
Indiana Michigan Pwr	Elec.	IN	√	√	--	√	√	√	--	√	√	√	--
Kentucky Pwr	Elec.	KY	√	√	--	√	√	√	√	--	--	√	O
Kingsport Power Co.	Elec.	TN	√	--	--	--	--	--	--	--	--	--	C
Ohio Pwr	Elec.	OH	D	√	--	√	√	--	D	√	√	√	P
Public Svc Co. of OK	Elec.	OK	√	√	--	√	--	√	--	√	√	√	--
Southwestern Elec Pwr	Elec.	AR	√	√	--	√	--	√	√	--	--	√	P
Wheeling Pwr	Elec.	WV	√	√	--	--	√	--	--	√	--	√	--
AVANGRID													
Central Maine Pwr	Elec.	ME	D	--	√	--	--	--	D	--	--	√	C
NY State E&G	Elec.	NY	D	--	√	--	√	--	D	--	--	--	C
Rochester G&E	Elec.	NY	D	--	√	--	√	--	D	--	--	--	C
United Illuminating	Elec.	CT	D	√	√	--	--	--	D	--	√	--	C
BLACK HILLS CORP.													
BH Power	Elec.	SD	√	√	--	√	--	√	--	--	√	√	--
Cheyenne Light	Elec.	WY	√	√	--	√	√	--	--	--	--	√	O
BH Colorado Elec	Elec	CO	√	√	--	--	√	--	√	√	--	√	--

ELECTRIC OPERATING COS.

			Type of Adjustment Clause (a)										
					Decoupling				New Capital				
Holding Company/ Operating Company	Type of Svc	State	Elec. Fuel/ Gas/ Purch. Pwr	Conserv. Program Expense	Full	Partial	Renew-ables Expense	Environ-mental Compliance	Gener-ation Capacity	Generic Infra-structure	Trans-mission Expense	Other	Future Test Year (b)
CENTERPOINT ENERGY													
Houston Electric	Elec.	TX	D	√	--	--	--	--	D	√	√	√	--
CMS ENERGY													
Consumers Energy	Elec.	MI	√	√	--	--	√	--	--	--	√	--	C
CONSOLIDATED EDISON													
Con Ed of NY	Elec.	NY	D	--	√	--	√	--	D	--	--	--	C
Orange & Rockland	Elec.	NY	D	--	√	--	√	--	D	--	--	--	C
DOMINION RESOURCES													
Virginia Electric Power	Elec.	VA	√	√	--	--	√	√	√	--	√	√	--
DTE ENERGY													
DTE Electric	Elec.	MI	√	√	--	--	√	--	--	--	√	--	C
DUKE ENERGY													
Duke Energy Carolinas	Elec.	NC	√	√	--	--	√	√	--	--	--	--	--
Duke Energy Florida	Elec.	FL	√	√	--	--	--	√	√	--	--	√	C
Duke Energy Indiana	Elec.	IN	√	√	--	√	√	√	√	√	√	√	--
Duke Energy Kentucky	Elec.	KY	√	√	--	√	√	--	--	--	--	√	O
Duke Energy Ohio	Elec.	OH	D	√	--	√	√	--	--	√	√	√	P
Duke Energy Progress	Elec.	SC	√	--	--	--	--	√	--	--	--	--	--
EDISON INT'L													
Southern California Ed.	Elec.	CA	√	--	√	--	--	--	--	--	--	--	C
EL PASO ELECTRIC													
El Paso Electric	Elec.	TX	√	√	--	--	--	--	--	√	--	√	--
ENTERGY CORP.													
Entergy Arkansas Inc.	Elec.	AR	√	√	--	√	--	--	√	√	√	√	P
Entergy Louisiana LLC	Elec.	LA	√	√	--	√	--	√	√	--	√	√	O
Entergy Mississippi Inc.	Elec.	MS	√	√	--	√	--	√	--	--	√	√	O
Entergy New Orleans Inc.	Elec.	LA	√	√	--	√	--	√	√	--	√	√	O
Entergy Texas Inc.	Elec.	TX	√	√	--	--	--	--	--	√	√	√	--

REGULATORY MECHANISMS

ELECTRIC OPERATING COS.

Holding Company/ Operating Company	Type of Svc	State	Type of Adjustment Clause (a): Elec. Fuel/ Gas/ Purch. Pwr	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renew-ables Expense	Environ-mental Compliance	New Capital: Gener-ation Capacity	New Capital: Generic Infra-structure	Trans-mission Expense	Other	Future Test Year (b)
EXELON CORP.													
Baltimore G&E	Elec.	MD	D	√	√	--	--	--	D	√	--	√	P
Commonwealth Edison	Elec.	IL	D	√	--	--	√	√	D	√	√	√	O
PECO Energy	Elec.	PA	D	√	--	--	--	--	D	√	--	√	O
Atlantic City Electric	Elec.	NJ	D	√	--	--	√	√	D	--	--	√	P
Delmarva P&L	Elec.	MD	D	√	√	--	--	--	D	√	--	--	P
Potomac Electric Pwr	Elec.	DC	D	--	--	√	√	--	D	√	--	√	P
IDACORP													
Idaho Power	Elec.	ID	√	√	√	--	--	--	--	--	--	--	P
NEXTERA ENERGY, INC.													
Florida Power & Light	Elec.	FL	√	√	--	--	--	√	√	--	--	√	C
NORTHWESTERN CORP.													
NorthWestern Corp.	Elec.	MT	√	√	--	--	--	--	--	--	--	√	--
OGE ENERGY													
Oklahoma G&E	Elec.	OK	√	√	--	√	√	√	--	√	√	√	--
OTTER TAIL CORP.													
Otter Tail Power	Elec.	MN	√	√	--	--	√	√	--	--	√	--	C
PG&E CORP.													
Pacific G&E	Elec.	CA	√	--	√	--	--	--	--	--	--	--	C
PINNACLE WEST													
Arizona Public Service	Elec.	AZ	√	√	--	√	√	√	√	--	√	√	--
PORTLAND GEN. ELEC.													
Portland General Electric	Elec.	OR	√	√	--	√	√	--	--	--	--	--	C
PPL CORP.													
Kentucky Utilities	Elec.	KY	√	√	--	√	√	√	--	--	--	√	O
Louisville G&E	Elec.	KY	√	√	--	√	√	√	--	--	--	√	O
PPL Electric Utilities	Elec.	PA	D	√	--	--	--	--	D	√	√	√	O
PUB SV ENTERPRISE GRP													
Pub Service E&G	Elec.	NJ	D	√	--	--	√	√	D	√	--	√	P

REGULATORY MECHANISMS

ELECTRIC OPERATING COS.

Type of Adjustment Clause (a)

Holding Company/ Operating Company	Type of Svc	State	Elec. Fuel/ Gas/ Purch. Pwr	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renewables Expense	Environmental Compliance	New Capital: Generation Capacity	New Capital: Generic Infrastructure	Transmission Expense	Other	Future Test Year (b)
SOUTHERN CO.													
Alabama Power	Elec.	AL	√	--	--	--	--	√	√	--	--	√	C
Georgia Power	Elec.	GA	√	--	--	--	--	--	√	--	--	--	C
Gulf Power	Elec.	FL	√	√	--	--	--	√	√	--	--	√	C
Mississippi Power	Elec.	MS	√	√	--	√	--	√	--	--	--	√	O
VECTREN CORP.													
Southern Indiana G&E	Elec.	IN	√	√	--	√	--	--	--	√	√	√	--
WEC ENERGY GROUP													
Wisconsin Electric Pwr	Elec.	WI	√	--	--	--	--	--	--	--	--	√	C
Wisconsin Public Service	Elec.	WI	√	--	--	--	--	--	--	--	--	√	C
XCEL ENERGY													
Northern States Pwr	Elec.	MN	√	√	√	--	√	√	--	--	√	--	C
Northern States Pwr	Elec.	WI	√	--	--	--	--	--	--	--	--	√	C
Public Svc. Co. of Colorado	Elec.	CO	√	√	--	--	√	√	√	√	--	√	--
Southwestern Public Svc.	Elec.	TX	√	√	--	--	--	--	--	√	√	√	--

Sources:

(a) Regulatory Research Associates, Regulatory Focus, *"Adjustment Clauses-A State-by-State Overview,"* Sep. 12, 2017.

(b) Edison Electric Institute, *"Alternative Regulation for Emerging Utility Challenges: 2015 Update,"* Nov. 11, 2015.

Notes:

D - Delivery-only utility.

C - Fully-forecasted test years commonly used in the state listed for this operating company.

O - Fully-forecasted test years occasionally used in the state listed for this operating company.

P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.

LIR - Limited issue reopeners.

FILED
June 18, 2020
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY PURSUANT TO IND. CODE § 8-1-39-9 FOR: (1) APPROVAL OF AN ADJUSTMENT TO ITS ELECTRIC SERVICE RATES THROUGH ITS TRANSMISSION, DISTRIBUTION, AND STORAGE SYSTEM IMPROVEMENT CHARGE ("TDSIC") RATE SCHEDULE, STANDARD CONTRACT RIDER NO. 3; AND (2) AUTHORITY TO DEFER 20% OF THE APPROVED CAPITAL EXPENDITURES AND TDSIC COSTS FOR RECOVERY IN PETITIONER'S NEXT GENERAL RATE CASE.	)	**CAUSE NO. 45264 TDSIC 1**

VERIFIED PETITION AND REQUEST
<u>FOR ADMINISTRATIVE NOTICE</u>

Indianapolis Power & Light Company ("IPL", "Petitioner" or "Company") respectfully petitions the Indiana Utility Regulatory Commission ("Commission") for: (1) approval of an adjustment to its electric service rates through a Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Rate Schedule, Standard Contract Rider No. 3 ("TDSIC Rider"), to effectuate the timely recovery of 80% of capital expenditures and TDSIC costs in connection with Petitioner's eligible transmission, distribution, and storage system improvements; and (2) authority to defer, as a regulatory asset, the remaining 20% of eligible and approved capital expenditures and TDSIC costs, with carrying costs, for recovery in Petitioner's next general rate case. IPL also requests the Commission to take administrative notice as set forth below. In support of this Verified Petition, IPL states as follows:

IPL's Corporate Status and Operations

1. IPL is an Indiana corporation with its principal office and place of business at One Monument Circle, Indianapolis, Indiana 46204. IPL is engaged in rendering electric utility service in the State of Indiana.

2. IPL provides retail electric utility service to more than 500,000 retail customers located principally in and near the City of Indianapolis, Indiana, and in portions of the following Indiana counties: Boone, Hamilton, Hancock, Hendricks, Johnson, Marion, Morgan, Owen, Putnam and Shelby Counties. IPL owns and operates electric generating, transmission and distribution plant, property and equipment and related facilities, which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light and power. IPL has maintained and continues to maintain its properties in a reliable state of operating condition.

Petitioner's "Public Utility" Status

3. IPL is a "public utility" under Ind. Code § 8-1-2-1 and Ind. Code § 8-1-39-4 and an "energy utility" under Ind. Code § 8-1-2.5-2. IPL is subject to the jurisdiction of this Commission in the manner and to the extent provided by the Public Service Commission Act, as amended, and other pertinent laws of the State of Indiana.

Relief Requested

4. The Commission approved IPL's TDSIC Plan by Order dated March 4, 2020 in Cause No. 45264 ("45264 Order"). In accordance with Ind. Code § 8-1-39-10(b), the Commission authorized TDSIC treatment for the improvements described in the IPL TDSIC Plan. The Commission directed IPL to file its TDSIC Plan updates and TDSIC rate updates separately on an

annual basis, staggered six months from each other, as subdockets in this Cause under the Cause No 45264 TDSIC X, with its first tracker filed on or before July 1, 2020. This Petition seeks to establish the "TDSIC rate" and addresses costs incurred under IPL's TDSIC Plan through March 31, 2020. IPL will file a TDSIC Plan update in December.

5. In this TDSIC rate filing, Petitioner respectfully requests approval of TDSIC Rider factors to effectuate the timely recovery of 80% of approved capital expenditures and TDSIC costs. The TDSIC 1 factors, when approved, are planned to go into effect starting with the November 2020 billing cycle and remain in effect until different Rider factors are approved, which is expected to be a period of approximately 12 months because IPL will seek approval of new factors in its TDSIC 3 filing. IPL asks the Commission to specifically approve and authorize recovery of the actual costs that exceed the amount previously approved. IPL also requests authority to defer, as a regulatory asset, the remaining 20% of approved capital expenditures and TDSIC costs, for recovery as part of IPL's next general rate case. IPL requests approval to adjust Petitioner's authorized return for purposes of Ind. Code § 8-1-2-42(d)(3) to reflect the incremental earnings that will result from this TDSIC Rider filing upon Commission approval. The proposed TDSIC Rider is included with IPL Witness Coklow's testimony as Attachment NHC-12.

Applicable Law

6. Petitioner considers Ind. Code §§ 8-1-39-9 and 12 of the Public Service Commission Act, as amended, among others, to be applicable to this Petition.

7. This Petition uses the customer class revenue allocation factors based on firm load approved in IPL's most recent retail base rate case order.

8. This Petition is not filed within nine months after October 31, 2018, the date of the Commission's order in IPL's most recent basic rate order in Cause No. 45029.

9. In accordance with Ind. Code § 8-1-39-9(e), IPL will petition the Commission for review and approval of its electric basic rates and charges before the expiration of its TDSIC Plan.

10. In accordance with Ind. Code § 8-1-39-9(f), IPL has not filed a petition under Ind. Code § 8-1-39-9 within the last six (6) months.

11. In accordance with Ind. Code § 8-1-39-9(g), IPL has, in its case-in-chief, provided specific justification for, and requests specific Commission approval of, actual capital expenditures and TDSIC costs that exceed the amounts approved in the March 4, 2020 Order in Cause No. 45264.

12. In accordance with Ind. Code § 8-1-39-14(a), IPL's proposed TDSIC Rider factors will not result in an average aggregate increase in Petitioner's total retail revenue of more than two percent (2%) in a twelve (12) month period.

Request for Administrative Notice.

13. Pursuant to 170 IAC 1-1.1-21, IPL requests administrative notice to be taken of the 45264 Order and the IPL TDSIC Plan approved by this Order. This order is available on the Commission's electronic docket. IPL will file a copy of the 45264 Order once this request is granted.

14. IPL's TDSIC Plan is Petitioner's Exhibit 2 in the record in Cause No. 45264. A complete copy of the public version Plan is attached hereto as Exhibit A and the unredacted copy is being filed with the Commission under seal in accordance with the docket entry in Cause No. 45264 dated August 7, 2019 authorizing the protection of this confidential information from

public disclosure. This document reflects the comprehensive compilation of the plan and appendices IPL presented in Cause No. 45264. Appendix 8.7 to this exhibit set forth the cost estimates, year by year project detail (sortable list) and plan projects by FERC account. For efficiency, IPL proposes that going forward, IPL's TDSIC Rider filings include Appendix 8.7 only and that the inclusion of this appendix be found to satisfy Ind. Code § 8-1-39-9(a)(2).

Procedural and Other Matters

15. IPL is filing its case-in-chief contemporaneous with its Petition, including direct testimony, attachments and workpapers of the following witnesses:

- Chad A. Rogers – Regulatory Policy
- James (Jim) William Shields Jr. – TDSIC Project Management
- Natalie Herr Coklow – Regulatory Accounting

16. The books and records of Petitioner supporting such data and calculations are kept in accordance with the Uniform System of Accounts for Electric Utilities prescribed by this Commission and are available for inspection and review by the Utility Consumer Counselor and this Commission.

17. Pursuant to 170 IAC 1-1.1-15(b) of the Commission's Rules of Practice and Procedure, IPL requests the Commission promptly conduct a prehearing conference and preliminary hearing to establish a procedural schedule in this Cause in accordance with Ind. Code § 8-1-39-12. In accordance with 170 I.A.C. 1-1.1-15(e), IPL will seek to enter into a stipulation with the Indiana Office of Utility Consumer Counselor regarding a procedural schedule in lieu of a prehearing conference.

18. In accordance Ind. Code § 8-1-39-12, the report of the OUCC (and intervenors, if any), is due not more than sixty (60) days after the filing of this Petition (Monday, August 17, 2020). The Commission order on this petition is due not more than one hundred twenty (120) days after the filing of this Petition (Friday, October 16, 2020). As noted above, IPL proposes to place the TDSIC Rider factors into effect with the November 2020 billing cycle which commences October 29, 2020.

Petitioner's Authorized Representatives

19. The name and address of Petitioner's duly authorized representative to whom all correspondence and communication concerning this Petition should be sent, is as follows:

Teresa Morton Nyhart (No. 14044-49)
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WHEREFORE, Petitioner respectfully requests that the Indiana Utility Regulatory Commission promptly publish notice, make such investigation and hold hearings as are necessary or advisable and thereafter, make and enter an order in this Cause approving this Petition and:

(1) approving the capital expenditures and TDSIC costs, including specifically the actual costs that exceed the previously approved estimates;

(2) approving timely recovery through IPL's TDSIC Rider of 80% of the approved capital expenditures and TDSIC costs;

(3) authorizing IPL to defer, as a regulatory asset, the remaining 20% of capital expenditures and TDSIC costs for recovery in IPL's next general rate case;

(4) approving IPL's TDSIC Rider and proposed factors;

(5) approving IPL's request of an adjustment to its authorized net operating income to reflect the approved earnings for purposes of Ind. Code § 8-1-2-42(d)(3); and

(6) granting to IPL such additional and further relief as may be deemed necessary or appropriate.

INDIANAPOLIS POWER & LIGHT COMPANY

Justin G. Sufan
Director, Regulatory & RTO Policy

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ATTORNEYS FOR PETITIONER INDIANAPOLIS POWER & LIGHT COMPANY

VERIFICATION

I affirm under penalties of perjury that the representations contained in the foregoing are true and correct to the best of my knowledge, information and belief.

Dated this 18th day of June, 2020.

Justin G. Sufan

CERTIFICATE OF SERVICE

The undersigned hereby certifies that on June 18, 2020, two copies of the foregoing Verified Petition and attachment were served by hand delivery and/or electronic mail upon the Office of Utility Consumer Counselor, PNC Center, 115 W. Washington Street, Suite 1500 South, Indianapolis, Indiana 46204; infomgt@oucc.in.gov.

Jeffrey M. Peabody

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ATTORNEYS FOR PETITIONER
INDIANAPOLIS POWER & LIGHT COMPANY

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INDIANA UTILITY
REGULATORY COMMISSION

Indianapolis Power & Light Company Transmission Distribution Storage System Improvement Charge (TDSIC) Plan

July 2019

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1 Introduction

1.1 Statutory Framework: Indiana Code Chapter 8-1-39

In 2013, the Indiana General Assembly passed Indiana Senate Enrolled Act 560 to address the issue of aging transmission and distribution infrastructure. This enactment was codified at Ind. Code § 8-1-39 (Transmission, Distribution, and Storage System Improvement Charges and Deferrals ("TDSIC") (referred to herein as the "TDSIC Statute"). The statute was amended in 2019.[1] The TDSIC Statute incentivizes the expeditious investment in and modernization of Indiana's energy delivery system infrastructure.

The TDSIC Statute contemplates two distinct types of proceedings.

First, Section 10 of the TDSIC Statute permits a public utility to petition the Indiana Utility Regulatory Commission ("IURC" or "Commission") for approval of the public utility's multi-year plan for eligible transmission, distribution, and storage improvements. Ind. Code § 8-1-39-10(a). This is referred to as the "TDSIC Plan" or "Plan." While the original statute provided for seven-year plans, the recent amendment provides for plans that are five to seven years.

As used in the statute, "eligible transmission, distribution, and storage system improvements" means new or replacement electric or gas transmission, distribution, or storage utility projects that: (1) a public utility undertakes for purposes of safety, reliability, system modernization, or economic development; (2) were not included in the public utility's rate base in its most recent general rate case; and (3) either were (A) described in the public utility's TDSIC Plan and approved by the Commission under section 10 of the statute and authorized for TDSIC treatment; (B) described in the public utility's update to the public utility's TDSIC Plan under section 9 of the TDSIC Statute and authorized for TDSIC treatment by the Commission; or (C) approved as a targeted economic development project under section 11 of the TDSIC Statute.

The 2019 amendment to the TDSIC Statute clarifies that the term "eligible transmission, distribution, and storage system improvements" includes: (1) projects that do not include specific locations or an exact number of inspections, repairs, or replacements, including inspection based projects such as pole or pipe inspection projects, and pole or pipe replacement projects; and (2) projects involving advanced technology investments to support the modernization of a transmission, distribution, or storage system, such as advanced metering infrastructure, information technology systems, or distributed energy resource management systems.

[1] See 2019 Indiana General Assembly, House Enrolled Act No. 1470.

The TDSIC Statute provides that after notice and hearing, and not more than 210 days after the petition is filed, the IURC shall issue an order that includes the following:

(1) A finding of the best estimate of the cost of the eligible improvements included in the plan;

(2) A determination whether public convenience and necessity require or will require the eligible improvements included in the plan; and

(3) A determination whether the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan.[2]

If the Commission determines that the public utility's TDSIC plan is reasonable, the Commission shall approve the plan and authorize TDSIC treatment (*i.e.,* the cost recovery provided in the statute) for the eligible transmission, distribution, and storage improvements included in the plan.[3] The 2019 amendments also expressly provide for the early termination of an existing TDSIC plan and for requests for approval of a new plan.[4]

The second type of proceeding is governed by Section 9 of the TDSIC Statute.[5] Section 9 allows the public utility to petition the Commission for periodic automatic adjustments of the utility's rates to timely recover eighty percent (80%) of approved TDSIC Plan capital expenditures and TDSIC costs.[6] The remaining twenty percent (20%) of the approved capital expenditures and TDSIC costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, is deferred for recovery as part of the utility's next general rate case, which the TDSIC Statute requires the utility to file before expiration of the plan.[7] Section 9 also requires the utility to update its TDSIC plan at least annually.[8] Finally, should actual TDSIC Plan capital expenditures and TDSIC costs exceed the Commission-approved estimates, the utility must provide specific justification and the Commission must specifically approve such costs before they may be recovered through customer rates.[9]

Consistent with the TDSIC Statute, IPL has developed a seven (7) year TDSIC Plan that is a comprehensive package of specific projects to improve and modernize the Company's energy delivery system, including the reliability thereof; safeguard public and employee safety; and support economic development.

[2] Ind. Code § 8-1-39-10(b).
[3] *Id.*
[4] See HEA 1470, Section 4 (adding subsection (d) to section 10 of the TDSIC Statute.
[5] Ind. Code § 8-1-39-9.
[6] "TDSIC costs" captures the following costs during and after construction: depreciation expenses; operations and maintenance expenses; extensions and replacements to the extent not provided for through depreciation, in the manner provided for in IC 8-1-1.5-3-8; property taxes; pretax returns. Ind. Code § 8-1-39-7.
[7] Ind. Code § 8-1-39-9(c), (e).
[8] See HEA 1470, Section 3 (amending section 9(b) of the TDSIC Statute).
[9] Ind. Code § 8-1-39-9(g). See HEA 1470, Section 3 (renaming subsection (f) to subsection (g)).

1.2 Executive Summary

Indianapolis Power & Light Company ("IPL") provides retail electric service to approximately 500,000 customers in Indianapolis and surrounding communities. IPL owns and operates an extensive system of transmission and distribution (T&D) substations, circuits and related assets, equipment and monitoring and control systems.

IPL's T&D assets are aging, growing obsolete, and require modernization. Many assets are beyond their expected service lives and will face increasing likelihood of failures if not replaced. When these assets fail, IPL makes emergency repairs and customers experience outages; safety hazards also arise. The continued integrity, reliability and resiliency of the T&D infrastructure is a driving force behind IPL's TDSIC Plan. The deployment of new infrastructure, including distribution automation capabilities, will drive operational and network efficiencies, improve reliability, better regulate voltage, and improve outage management functions. The infrastructure improvements will also accommodate new demands from IPL customers who are deploying more sophisticated distributed energy resources and seeking additional levels of service.

IPL's TDSIC Plan proposes seven years of defined investment, totaling $1.2 billion, to replace, rebuild, upgrade, redesign and modernize a wide range of IPL's aging T&D system assets in two thematic areas: *Age and Condition*, and *Deliverability*.

The *Age and Condition* (83.3% of the estimated Plan cost) category addresses the many risks posed by aging assets. The category includes the replacement and rebuilding of substations and overhead circuits, the rehabilitation and repair of underground residential circuits, and rebuilding portions of the central business district. The *Deliverability* (16.7% of the estimated Plan cost) category deploys new technologies for advanced distribution management, adds new substation equipment to meet growth-driven capacity requirements, and creates system and operating efficiencies through automation, control functions and other advanced infrastructure.

Both categories support IPL's ability to maintain and operate the grid in a safe, reliable and efficient manner. Many of the modernizing improvements are focused on giving IPL's operators and engineers more information and control over the grid for purposes of delivering a better, more efficient energy experience. Other Projects target improvement in overall levels of reliability and integrity. A hardened and resilient grid can better withstand the impact of weather and is easier to restore when outages inevitably occur.

IPL's TDSIC Plan aligns with the TDSIC Statute as the Projects are undertaken for the purpose of safety, reliability, system modernization, and support of economic development. The estimated cost of the improvements included in the IPL TDSIC Plan costs are justified by incremental benefits attributable to the Plan. More specifically, the seven Projects that lend themselves to monetization, when viewed as part of a total portfolio, will provide a net benefit (i.e.; total escalated nominal benefits less the total escalated nominal cost of the Plan) of $939 million to

IPL's customers over a 20-year period. There are also a host of qualitative benefits, introduced in Section 3 (TDSIC Benefits) and expanded upon in the Section 6 (TDSIC Project Narratives) that combined with these quantifiable benefits, clearly meets the intent of the TDSIC Statute. Furthermore, without these improvements IPL's T&D system will face increasing levels of risk, and an erosion in overall grid integrity and reliability, which will be difficult to correct.

1.3 IPL's Transmission & Distribution System Overview

IPL's service area measures approximately 528 square miles.[10] IPL, headquartered in Indianapolis, is subject to the regulatory authority of the IURC and the Federal Energy Regulatory Commission ("FERC"). Additionally, IPL participates in the electricity markets managed by the Midcontinent Independent System Operator ("MISO").

IPL serves its customers through an interconnected grid of T&D circuits and substations as a vertically integrated investor-owned utility. This grid is comprised of a diverse set of company owned and operated assets, which are aging and, in some cases, nearing obsolescence.

The IPL transmission system consists of approximately 458 circuit miles of lines at 345,000 volts ("345 kV"), 408 circuit miles of line at 138,000 volts ("138 kV") and associated substations. There is a 345 kV ring around Marion County with multiple lines that interconnect into the ring at four different locations. Inside of the 345 kV ring is a 138-kV ring/grid. These two rings are connected through 345 kV to 138 kV auto transformers at six locations. This allows power to flow from the 345 kV transmission system to the 138 kV system. IPL has generation connected to the 345 kV system at the Petersburg ("Pete") Generating Station and generation connected to the 138 kV system at Harding Street Station ("HSS"), Eagle Valley ("EV") Station, and the Georgetown Generating Station.

The IPL transmission system operates as part of a larger integrated network system, commonly referred to as the Eastern Interconnection. The IPL transmission system is directly connected to the transmission systems of Indiana Michigan Power Company ("AEP"), Vectren Corporation ("Vectren"), Hoosier Energy Rural Electric Cooperative, Inc. ("HE"), and the electric system jointly owned by Duke Energy Indiana ("Duke"), Indiana Municipal Power Agency and Wabash Valley Power Association, Inc.

Through the interconnections with these other utilities, power can flow into and out of the IPL transmission system. The IPL transmission system is connected at both the 345 kV and 138 kV level with the other utilities. At the Petersburg Generation Station there are 345 kV level interconnections with Duke and AEP and 138 kV level interconnections with Duke, Vectren, and

[10] See Appendix 8.1 of IPL's TDSIC Plan for map of IPL's service area.

HE. In the Indianapolis area, IPL's transmission system has two 345 kV level interconnections with Duke and AEP and 138 kV level interconnections with Duke.

The distribution system consists of 4,961 circuit miles of underground primary and secondary cables and 6,110 circuit miles of overhead primary and secondary wire. Underground street lighting facilities include 773 circuit miles of underground cable. Also included in the system are 138 substations. Depending on the voltage levels at the substation, some substations may be considered both a bulk power substation and a distribution substation. There are 73 bulk power substations and 117 distribution substations; 52 substations are considered both bulk power and distribution substations. IPL uses a Secondary Network System to serve the City of Indianapolis Central Business District, sometimes also referred to as the "Mile Square." A unique feature of the Secondary Network System is the loss of a single component, such as a primary feeder or a network transformer, typically will not result in any customer losing power.

2 IPL's TDSIC Plan

2.1 The Modernizing Opportunity

IPL has several core opportunities related to its T&D assets and systems.

- First, IPL's T&D aging infrastructure requires modernization. Many of these assets are beyond their expected service lives and will face increasing likelihood of failures if not replaced. When these assets fail, which can lead to power outages, IPL must make emergency repairs; safety hazards can also arise during these outages depending on their nature.
- Second, grid assets require modernization to accommodate new demands from IPL customers who are deploying more sophisticated distributed energy resources and seeking additional levels of service.
- Third, with the deployment of new grid technologies, IPL's capability to operate and maintain the grid in a reliable, cost-effective, safe and efficient manner will be enhanced.

IPL must address these modernization opportunities to continue to operate and maintain a safe and reliable grid. Absent action, the reliability and integrity of IPL's T&D infrastructure may decline, safety levels will erode, and customer satisfaction with IPL's service will suffer. Customers will experience more persistent and more frequent power outages.

2.2 The Solution: IPL's TDSIC Plan

To address these modernization opportunities, -- and mitigate the reliability and integrity risks attendant to them -- IPL is proposing a seven-year, $1.2 billion TDSIC Plan to rebuild, upgrade, replace and modernize a wide range of IPL's aging transmission and distribution system assets.

The seven-year TDSIC Plan is guided by the TDSIC Statute. IPL's TDSIC Plan is summarized in Table 2.1 below.

Table 2.1 – IPL's TDSIC Plan Projected Annual Capital Costs (in millions)

Project Type	2020	2021	2022	2023	2024	2025	2026	7-Year Total
Age & Condition Projects								
Circuit Rebuilds	$ 27.2	$ 25.3	$ 45.8	$ 52.8	$ 47.8	$ 49.9	$ 49.9	$ 298.7
Substation Assets Replacement	$ 16.7	$ 27.0	$ 39.9	$ 39.2	$ 34.5	$ 44.3	$ 46.5	$ 248.1
XLPE Cable Replacement	$ 12.2	$ 11.8	$ 12.5	$ 12.4	$ 12.3	$ 12.8	$ 12.3	$ 86.2
4 kV Conversion	$ 19.7	$ 13.8	$ 15.4	$ 15.5	$ 7.6	$ 12.4	$ 7.5	$ 92.0
Tap Reliability Improvement Projects	$ 10.9	$ 10.4	$ 10.6	$ 10.8	$ 11.0	$ 11.3	$ 11.5	$ 76.5
Meter Replacement	$ 10.7	$ 11.0	$ 11.2	$ 11.4	$ 11.6	$ -	$ -	$ 55.9
CBD Secondary Network Upgrades	$ 4.6	$ 5.9	$ 5.3	$ 5.9	$ 5.0	$ 5.9	$ 6.4	$ 39.0
Static Wire Performance Improvement	$ 4.8	$ 6.9	$ 9.5	$ 11.2	$ 11.5	$ 10.7	$ 7.6	$ 62.1
Remote End - Breaker Relay/Upgrades	$ 3.0	$ 2.0	$ 5.6	$ 1.6	$ 6.2	$ 3.1	$ 6.4	$ 28.0
Pole Replacements	$ 3.3	$ 3.3	$ 3.4	$ 3.5	$ 3.5	$ 3.6	$ 3.7	$ 24.2
Steel Tower Life Extension	$ 1.1	$ 1.1	$ 1.1	$ 0.9	$ -	$ -	$ -	$ 4.2
Age & Condition Projects Total	$ 114.2	$ 118.6	$ 160.3	$ 165.1	$ 151.0	$ 153.9	$ 151.8	$ 1,015.0
Deliverability Projects								
Distribution Automation	$ 18.8	$ 19.2	$ 13.6	$ 13.9	$ 14.2	$ 14.5	$ 14.8	$ 109.0
Substation Design Upgrades	$ 3.8	$ 16.2	$ 15.8	$ 32.9	$ 6.3	$ 16.8	$ 2.6	$ 94.5
Deliverability Projects Total	$ 22.6	$ 35.4	$ 29.5	$ 46.8	$ 20.5	$ 31.3	$ 17.4	$ 203.5
Total Capital Costs	**$ 136.8**	**$ 154.0**	**$ 189.7**	**$ 212.0**	**$ 171.5**	**$ 185.2**	**$ 169.2**	**$ 1,218.5**
Amount of Transmission	$ 22.4	$ 27.6	$ 33.7	$ 36.4	$ 33.6	$ 29.3	$ 30.6	$ 213.7
Amount of Distribution	$ 114.4	$ 126.4	$ 156.0	$ 175.5	$ 137.9	$ 155.9	$ 138.6	$ 1,004.7
Total Capital Costs	**$ 136.8**	**$ 154.0**	**$ 189.7**	**$ 212.0**	**$ 171.5**	**$ 185.2**	**$ 169.2**	**$ 1,218.5**

To assist in describing the Plan, IPL organized its TDSIC proposal within two thematic areas: *Age and Condition*, and *Deliverability*. *Age and Condition* covers the IPL TDSIC Plan Projects that address the many risks posed by aging assets. Amongst other items, these project categories are devoted to the replacement and rebuilding of substations and overhead circuits, the rehabilitation and repair of underground residential circuits, and to rebuilding portions of the central business district. *Age and Condition* covers approximately 83.3% of the Plan's estimated cost.

The *Deliverability* category forms the remaining Projects and comprises 16.7% of the Plan's estimated cost. This Project group brings new technologies to:

- deploy Distribution Automation control system,
- add new substation equipment to meet growth-driven capacity requirements, and
- create system and operating efficiencies through automation, control functions and other advanced infrastructure.

Projects in both plan categories -- *Age and Condition* and *Deliverability* -- support IPL's ability to maintain and operate the grid in a safe, reliable and efficient manner. Many of the modernizing improvements are focused on giving IPL's operators and engineers more information and control over the grid for purposes of delivering a better, more efficient energy experience. Other projects target improvement in overall levels of reliability and integrity. A hardened and resilient grid is one that can better withstand the impact of weather and is easier to restore when outages inevitably occur.

2.3 Asset Management

IPL has a well-established asset management framework, which was recently the subject of a stakeholder collaborative discussion conducted in accordance with the Commission order in Cause No. 44576. In assembling this TDSIC Plan, the asset management principles already in place were applied and relevant data, information and tools were used to develop investment projects. For example, IPL's compilation of asset condition data allows the 'effective age' of the assets to be estimated. The asset management work done to date provided a solid foundation to build from in the development of the TDSIC Plan.

2.4 TDSIC Plan Development

To develop the proposed TDSIC Plan, IPL conducted an iterative process to prioritize system needs and determine how to best address aging infrastructure while also building a modern grid that is ready and able to meet the demands of the future. IPL relied on subject matter experts who operate and maintain the IPL electric system.

IPL also engaged a third-party consultant, Burns & McDonnell Engineering Company, Inc. ("BMcD") to assess asset risk and prioritize investment. To provide further rigor to the analysis, IPL engaged Black & Veatch ("B&V") Corporation to review the Risk Model, validate the cost estimates, and otherwise assist in the development of the TDSIC Plan.

IPL considered feasibility in developing the scope and schedule of the proposed improvements. Feasibility has many underlying aspects, and includes considerations such as: (a) protecting public and worker safety, (b) recruiting and providing sufficient skilled labor, (c) contracting in such a way to provide for the on-time availability of needed equipment on reasonable commercial terms, (d) attending to back office capabilities (for such requirements as design work) in order to meet the demands of managing plan implementation, (e) securing necessary local permits, and (f) designing a schedule and pace for the work that minimizes customer power disruptions.

Section 6 provides further detail on each TDSIC Plan Project and associated benefits.

3 TDSIC Plan Benefits

3.1 Overview

The TDSIC Statute requires that the Commission order include a determination whether the estimated costs of the TDSIC Plan improvements are justified by incremental benefits attributable to the Plan. Consistent with this criterion, IPL has crafted a well-balanced and feasible Plan that reduces safety-related risks, improves reliability, advances system modernization, and supports economic development. Among several qualitative benefits, some of which can be quantified, there is a full array of anticipated benefits:

- Reduction of the average effective age of major assets and associated asset risk, decreasing the number and impact of faults occurring on the system.

- Improved safety by replacing aging and obsolete assets. IPL will be able to counter the effects of aging infrastructure by replacement, which in turn will maintain safety.

- Reduction of equipment failure caused outages, enabling IPL to sustain the system's reliability and integrity on a go-forward basis.

- Greater system resiliency, placing IPL in a better position to withstand system events with fewer impacts. Fewer customers will experience power outages and the time required to make repairs and restore service will be reduced.

- Modernization with the addition of new assets that meet modern design and engineering standards. The associated increase in modern diagnostic capabilities will improve the overall monitoring, outage response, and control functions, and lay the foundation for effective predictive maintenance of IPL's most critical assets.

- Modernization also provides a foundation for IPL to offer new energy services and integrate them with the utility grid.

- Self-healing (automatic restoration) and corresponding improved service restoration due to the installation of new distribution automation capabilities.

- Improved efficiencies of the distribution system that will result in better voltage regulation, higher degrees of power quality, and a reduction of energy consumption by IPL customers. In addition to supporting the growing demand for distributed resources, these efficiencies will translate into energy consumption savings.

- Enhanced customer experience through improved outage management and communication capabilities that will lead to a reduction in outage frequency and duration.

- Improved customer service through the acceleration of IPL's advanced smart metering initiative. This lays the foundation for customers to receive better and more meaningful information about their energy usage, enabling more informed choices, and they will benefit from quicker resolution of any billing inquiries and experience greater convenience in establishing or discontinuing service.

- Economic development in the communities to which IPL provides electric service.

In further reviewing this list of benefits (expanded upon in Section 6, "TDSIC Project Narratives", for each individual project), one can group the Plan benefits into one of the following seven categories:

1.) **Customer Experience** - a qualitative measure, defined in terms of information quality and availability, choices, and interconnection options.
2.) **Reliability and Resiliency** - the capability to meet the electric demands of customers while providing uninterrupted electric service, including momentary interruptions; and in the case of major outages and disturbances, withstand and quickly recover service.
3.) **Safety** – reducing the risk of harm to people and property posed by the potential physical hazards associated with IPL owned, operated and maintained T&D assets.
4.) **Operational Efficiency** - activities and investments that reduce or lessen upward pressure on IPL operating costs, improve worker productivity, lower the difficulty and/or complexity of IPL employee tasks, reduce future capital expenditures, and/or directly lower customer energy costs.
5.) **Risk Reduction** – consistent with the key elements of the ISO 31000 standard, activities and investments that will reduce the likelihood and/or consequence of an asset failure, thus improving reliability, reducing hazards, and reducing unplanned replacement of critical assets.

6.) **Power Quality** – reducing the number and magnitude of disturbances such as high or low voltage, voltage spikes and transients, flickers and voltage sags, surges and short-time over voltages, as well as harmonics and noise.

7.) **Modernization** – replacing and adding assets with modern equipment/material or adding new technology onto the system for improved performance, functionality and operational efficiency.

Table 3.1 below provides an overall view of the Plan's benefits. Viewed in this manner it is seen that the benefits of the Plan are spread across the full array of the benefit categories.

Table 3.1 – Mapping of Projects to Benefit Categories

	Project	Customer Experience	Reliability and Resiliency	Safety	Operational Efficiency	Risk Reduction	Power Quality	Modernization
	Age and Condition							
1	Circuit Rebuilds	X	X	X		X	X	
2	Substation Assets Replacement	X	X	X	X	X	X	X
3	XLPE Cable Replacement	X	X	X	X	X	X	X
4	4 kV Conversion		X	X	X	X	X	X
5	Tap Reliability Improvement Projects	X	X	X	X	X	X	
6	Meter Replacement	X		X	X		X	X
7	CBD Secondary Network Upgrades	X	X	X	X	X	X	X
8	Static Wire Performance Improvement	X	X	X	X	X	X	X
9	Remote End - Breakers Relay/Upgrades	X	X	X	X	X	X	X
10	Pole Replacements		X	X	X	X		
11	Steel Tower Life Extension		X	X	X	X		
	Deliverability							
12	Distribution Automation	X	X	X	X	X	X	X
13	Substation Design Upgrades	X	X	X	X	X	X	X

The following discussion expands further on the value of the Plan, by monetizing those aspects that lend themselves to such an approach yet adopts a conservative posture to avoid overstating these quantitative benefits. Though quantifying savings is important, IPL holds firm to the notion that the Plan provides benefits, both quantitative and qualitative, that far exceed these calculations.

IPL's monetization approach of the calculated benefits is discussed below, and the more qualitative or time-based (*e.g.,* AMI) benefits are further expounded upon in Section 6 of this Plan.

3.2 Monetization of the Benefits

3.2.1 Monetization Approach Overview

In developing a directionally accurate view of the monetized benefits of the Plan, IPL established the following criteria to drive its approach:

- Incorporate conservatism in projecting actual savings:
  - Adopted the averages of ranges for unitized costing (particularly relating to productivity improvements attributable to proactive versus reactive work, benefit capture planning horizon of 20 years, and costs attributable to a customer-experienced outage), and
  - Focused on the consequence areas in the Risk Model that can be more readily quantified (i.e., reactive vs proactive replacement and customer reliability).
- Apply the Risk Modeling framework and approaches used in developing the Plan:
  - Focused the monetization analysis on the five Projects for which the Risk Model calculated risk scores (i.e., Circuit Rebuilds, Substation Assets Replacement, XLPE Cable Replacement, 4 kV Conversion, and Remote End-Breaker/Relay Upgrades).
  - Applied a cost factor to account for the savings resulting from less reactive maintenance.
  - Applied the DOE Interruption Cost Estimate ("ICE") Calculator[11], used across the industry to estimate the interruption costs and/or benefits associated with reliability improvements to monetize risk costs. In keeping with our conservative approach, large C&I customers, though extremely significant in terms of impact on these risk costs, were not factored in this portion of the monetization effort.
- Where appropriate, maintain consistency in applying assumptions to the analytics used throughout the monetization analysis:
  - Deployed the DOE ICE Calculator to monetize projected customer savings relating to the Tap Reliability Improvement Projects and the self-healing aspect of Distribution Automation Project. IPL applied the same approaches and factors as those used for the five Projects for which the Risk Model calculated risk scores, except that for Distribution Automation where the full customer mix (i.e., residential, small C&I and large C&I), was considered.
  - Maintained a conservative posture in projecting savings attributable to the reduction in energy consumption related to the Distribution Automation Project.

[11] The DOE funded Interruption Cost Estimate ("DOE ICE Calculator") is an electric reliability planning tool developed by Freeman, Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The DOE ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy.

- Established a 20-year planning horizon for the capture of benefits.
- Used escalation and discount rates identical to those used in the IPL TDSIC Plan (2.0 percent and 6.6 percent respectively).

- Approach monetization from a portfolio perspective to avoid the double-counting of benefits attributable to the inherent inter-relationships among the 13 Projects. In so doing, IPL monetized the benefits for seven of the thirteen TDSIC Projects.

3.2.2 Self-Healing/Reliability Monetization

IPL monetized the self-healing aspect of the Distribution Automation and the Tap Reliability Improvement Projects, deploying the DOE ICE calculator:

- Distribution Automation

  The first benefit monetized under Distribution Automation Project was that associated with the Fault Location, Isolation, and Service Restoration (FLISR) functionality. This functionality is estimated to eliminate, on average, 23,000 customer interruptions per year, and reduce the duration of approximately 167,000 interruptions per year to less than 5 minutes. Using the DOE ICE Calculator, IPL calculated that its customers will realize about $21 million of value per year when the Project is completed, translating to an escalated nominal increased value of $428.8 million over the 20-year period. Key factors were considered in arriving at this figure:

  - In determining the requirement for 1,200 reclosers, IPL conducted a detailed reliability optimization analysis, defining the amount of sectionalizing that will yield the highest benefit to cost ratio in reliability. This analysis resulted in 400 customer sectionalizing sections for the FLISR portion of Distribution Automation.

  - In applying the DOE ICE Calculator to determine the financial benefits from the customer perspective, IPL accounted for the full customer experience (e.g., included Major Event Days and to properly account for momentary interruptions).

  - Applied IPL's customer mix (residential, small commercial and industrial and large commercial and industrial) and Indiana factors in calculating the savings (refer to Table 3.2).

Table 3.2 – Avoided Customer Interruptions Cost Factors by Customer Type

Customer Type	Unplanned Outage	Momentary Outage
Residential	$7.08	$4.81
Small C&I	$1,135.28	$493.81
Large C&I	$6,623.14	$3,364.44

- The actual realization of any savings was delayed until the beginning of the fourth year of the Plan, reflecting the anticipated installation of the Advanced Control System.

- Tap Reliability Improvement Projects

The primary purpose of this Project is to reduce the number of sustained outages on under-performing overhead fused taps. As a starting point, IPL reviewed historical outage information over a 3-year period and identified 306 taps as likely candidates for this Project. From that list, 20 were selected for the first year of the Project, understanding that a rolling 3-year history will be used to select future taps for reliability improvement. Based on the overhead and underground solutions chosen to improving performance on the 20 chosen fused taps, IPL predicts an overall year one reliability improvement of 75 percent (reflecting a split largely weighted towards underground taps where nearly a 100 percent improvement can be expected; less so for overhead in the range of 50 percent). As the Projects progresses to year seven, IPL assumes a steady decrease in the improvement opportunity, after which the projected "savings" will level off after year seven and stay constant through year 20.

For the purpose of monetization, IPL calculated Repair and Line Clearance savings as well as those related to Customer Reliability.

- Repair and Line Clearance: A per outage cost of $3,000 was calculated by determining the total amount of unplanned outage repair incurred in 2018 and dividing that number by the total number of unplanned outages. Line clearance savings were calculated based on current price per mile estimates for the portions that are converted to underground. Applying this factor resulted in total projected escalated nominal savings of $49.8 million over the 20-year period.

- Customer Reliability: This project eliminates sustained outages. IPL applied the DOE ICE Calculator, applying the same sustained outage factors as those used for the Distribution Automation Project. The resulting escalated nominal value over the 20-year period totaled $207.0 million.

3.2.3 Conservation Voltage Reduction Monetization

The second benefit monetized under the Distribution Automation Project were the benefits associated with Conservation Voltage Reduction. The monetization of these benefits focuses on the enablement of voltage control which is estimated to reduce customer energy consumption by one percent, saving 112,000 MWh per year. In first arriving at the 112,000 MWh saved per year, IPL adopted a conservative approach:

- Through actual testing, IPL calculated that a one percent decrease in voltage will result in a 0.65 percent reduction in consumption (referred to as the Conservation Voltage Reduction factor). Anticipating a reduction in this factor over time, IPL reduced it to 0.50 percent to calculate energy savings.
- Once deployed, the Distribution Automation Control System will decrease distribution system voltage by 2 percent on the 13.2 kV circuits where it is applied.
- Applying the Conservation Voltage Reduction Factor to the 2 percent reduction in voltage, IPL arrived at the one percent reduction in energy consumption or 112,000 MWh reduction annually.

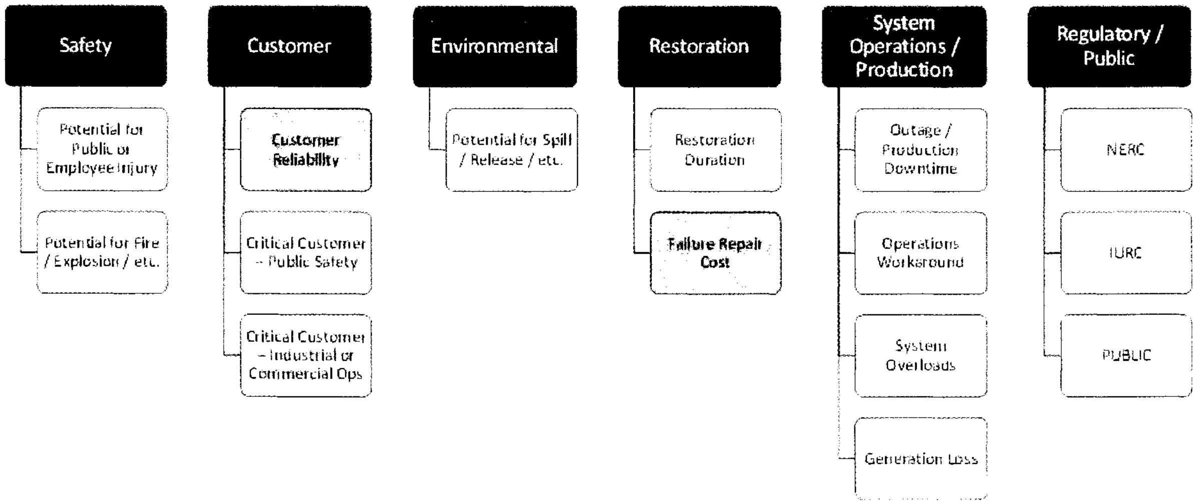
Further, the actual realization of any savings was delayed until the beginning of the fourth year of the Plan, accounting for the anticipated installation of the Advanced Control System and the integration of new and existing IT systems associated with the deployment of the Advanced Control System.

The projected escalated nominal savings of this aspect of the Distribution Automation Project over the 20-year period is $67.7 million.

3.2.4 Risk Reduction Monetization

Risk reduction monetization focused on the savings associated with reactive replacement of aged assets versus the proactive replacement of aged assets and the reliability improvements associated avoiding outages associated with assets that fail. The monetization of risk reduction only considered the five Projects for which the Risk Model calculated risk scores. And, as Figure 3.1 illustrates, the actual risk monetization was performed for a subset of the Consequence of Failure criteria.

Figure 3.1 – Consequence of Failure Criteria



NOTE: Shading reflects focus of the effort to monetize risk showing that only 2 of the 6 domains that define the Consequence of Failure (CoF) Criteria in the Risk Model were included in the monetized analysis. Further, of the 15 categories that define these domains, only two (less than 15 percent) were actually monetized.

- Reduction of Reactive Work: Focused on the difference between planned and reactive work, leveraging potential savings relating to reduced:
  - Overtime,
  - Premiums to make last minute purchase of equipment and materials,
  - Mobilization and rework related to making temporary fixes and returning to effect permanent repairs / replacements, and
  - Schedule disruption in reassigning crews, previously deployed on other work, on emergent activities.

  Applying a 40 percent factor to account for these premium costs (industry norms range between 30 and 50 percent with isolated examples of factors considerably higher), provides a projected escalated nominal benefit over the 20-year period of $532 million.

- Residential and Small C&I Reliability: Incorporated the DOE ICE Calculator, assuring alignment with the above stated factors used in monetizing the reliability portion of the Distribution Automation and Tap Reliability Improvement Projects; omitting the Large C&I customers and assuming full deployment of the Advanced Control System at the onset of the Plan. The resulting calculation provides a projected escalated nominal value over the 20-year period of $872 million. [12]

[12] See also Appendix 8.11 Risk Reduction Benefit Monetization Report.

3.3 Summary

The benefits and projected outcomes of the Plan considerably exceed its cost. Viewed as a portfolio of key capital investments:

- There are several qualitative benefits that do not lend themselves to monetization, but clearly bring value to our customers (*e.g.,* improved customer experience, power quality and modernization),
- There are additional benefits (*e.g.,* safety and environmental) that are hard to quantify and monetize (i.e., IPL opts to not place a specific dollar value on health and safety). In these instances, the quantification of benefits by the Plan is conservative by not assigning to them a dollar value, and
- There are areas where monetization analyses can be performed, while maintaining a conservative view towards projected savings / financial benefits to our customers. These are summarized in Table 3.3 below.

Table 3.3 – Summary of Monetized Benefits (20-Year Period)

Project	Category	Nominal Benefit ($M)
Distribution Automation	Self-Healing / Reliability	$429
	Conservative Voltage Reduction	$68
Tap Reliability Improvement Program	Repair / Line Clearance	$50
	Customer Reliability	$207
Asset Replacement Projects[1]	Reduction of Reactive Work	$532
	Customer and Small C&I Reliability	$872
	Total Monetized Benefit	**$2,158**
	TDSIC Plan Investment	($1,219)
	Net Monetized Benefit	**$939**

NOTE 1: The Asset Replacement Projects refer to an aggregation of the monetized benefits attributable to the Circuit Rebuilds, Substation Assets Replacement, XLPE Cable Replacement, 4 kV Conversion, and Remote End-Breaker/Relay Upgrades projects.

IPL notes that some specific projects presented in the Plan, viewed individually, will not produce monetized benefits equal to or greater than the proposed investment level (specifically, Substation Assets Replacement and Remote End – Breaker/Relay Upgrades Projects). This is reasonable due to the inherent redundancy built into substations for reliability purposes. Substation assets identified for replacement in the Plan are intended to maintain or enhance this existing inherent redundancy and the associated reliability levels they have historically produced. Thus, viewed as a total portfolio, the combined value (*i.e.,* benefit to our customers) of the Plan clearly meets the intent of the TDSIC Statute as it pertains to incremental benefits attributable to the Plan.

4 Best Estimates of Project Costs

4.1 Guidance Criteria: The AACE Cost Classification System

AACE International is an association that focuses on furthering approaches to total cost management and cost engineering. As a recognized leader in cost estimating, AACE has provided guidelines that are widely used in the utility industry to standardize approaches to project cost estimating. The Cost Estimate Classification System recommended by AACE International provides guidelines for applying the principles of cost estimating across the phases and stages of project cost estimates. This recognized cost classification system has been applied to other regulatory filings in Indiana.

AACE's Cost Estimate Classification System, presented in Table 4.1 below, maps the phases and stages of project cost estimating together with a generic maturity and quality matrix that can be applied across a wide variety of industries. This matrix describes a range of five estimate classes, with Class 1 estimates being the most detailed with the narrowest range of accuracy of -10% to +15% and at the furthest, Class 5 estimates which have less detail and an expected accuracy ranging from -50% to +100%.

Table 4.1 – AACE Cost Estimate Classification Matrix*

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

*Note: The above table has been re-produced in-part using data from "AACE International Recommended Practice No.18R-97: COST ESTIMATE CLASSIFICATION SYSTEM - AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES, Rev. March 1, 2016".

4.2 AACE - Class 2, Class 3 and Class 4 Distinctions

AACE defines the characteristics of each estimating class. The following is a summary of Class 2, Class 3 and Class 4 AACE Estimate Classification.

Class 2 estimates involve a high degree of deterministic estimating methods. Class 2 estimates are prepared in detail, and often involve numerous unit cost line items. Engineering is typically 30% to 75% complete. Class 2 estimates are used to prepare baseline schedules and budgets against which all actual costs and resources will be monitored for variations to the budget and form a part of the change management program.

Class 3 estimates involve a lesser degree of deterministic estimating methods than Class 2 estimates. Class 3 estimates form the basis for budget authorization and funding levels. Engineering is typically 10%-40% complete. Class 3 estimates rely on unit cost line items. This allows for factoring to obtain costs estimates.

Class 4 estimates are parametric in nature and are developed based on limited information. Parametric estimates rely on previous cost of similar projects or recent cost estimates. Class 4 estimates are used for preliminary budget approval. Engineering is typically 1%-15% complete.

4.3 Contingency, Indirect Costs and Inflation

Estimate accuracy range is an indication of the degree to which the final cost outcome for a given project will vary from the estimated cost. Accuracy is traditionally expressed as a +/- percentage range around the point estimate after application of contingency.

Contingency is applied to projects depending upon the technical complexity and the availability of appropriate cost reference information. The degree of project definition should also be considered in determining the appropriate contingency. As the degree of project definition increases, the expected accuracy of the estimate tends to improve, and the level of contingency required is reduced. For most projects in the IPL TDSIC Plan a 10% contingency was applied. For the Central Business District ("CBD") Secondary Network Upgrades Project, a 20% contingency was applied due to complexity of excavating in the downtown area. Likewise, the Distribution Automation control system component of the Distribution Automation Project also received a 20% contingency due to the complexity of deploying an Advanced Control System. The Meter Replacement Project received a 1% contingency due to the low complexity of the work, purchasing and replacing meters.

Both Allowance for Funds Used During Construction ("AFUDC") and Indirect Capital costs were applied to IPL's cost estimates. Both are variable costs that projects incur during construction. AFUDC charges were calculated using the current cost of capital and an estimation of project duration. Indirect Capital costs were estimated as a percentage of the project cost.

Lastly, project costs were escalated at the Consumer Price Index rate of 2% per year to account for inflation.

4.4 IPL's Cost Estimate Development Methodology

IPL developed cost estimates for projects included in the proposed 7-year TDSIC Plan. As shown in Table 4.2 below, AACE Class 2 estimates were developed for nine of the Projects for Year 1 and Year 2 of the Plan. Four of the Projects have Class 3 estimates for Year 1 and Year 2. For Tap Reliability Improvement Projects (TRIP's) Class 2 estimates were developed for the first year. Class 4 estimates were used for TRIP Project years 2 through 6 based on the method of defining the scope of these projects. Further explanation of TRIP's projects can be found in the TRIP project narrative in Section 6.5. For the remaining years of the Plan (Years 3-7), AACE Class 4 estimates were used due to limited scope definition and potential cost fluctuations.

Table 4.2 – Project Cost Estimate Classification by Year

	Plan Year						
Project	**1**	**2**	**3**	**4**	**5**	**6**	**7**
			Age & Condition				
Circuit Rebuilds	Class 2	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4
Substation Assets Replacement	Class 2	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4
XLPE Cable Replacement	Class 3	Class 3	Class 4	Class 4	Class 4	Class 4	Class 4
4 kV Conversion	Class 2	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4
Tap Reliability Improvement Projects	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4	Class 4
Meter Replacement	Class 2	Class 2	Class 4	Class 4	Class 4		
CBD Secondary Network Upgrades	Class 2	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4
Static Wire Performance Improvement	Class 2	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4
Remote End - Breaker Relay/Upgrades	Class 2	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4
Pole Replacements	Class 3	Class 3	Class 4	Class 4	Class 4	Class 4	Class 4
Steel Tower Life Extension	Class 3	Class 3	Class 4	Class 4			
			Deliverability				
Distribution Automation	Class 3	Class 3	Class 4	Class 4	Class 4	Class 4	Class 4
Substation Design Upgrades	Class 2	Class 2	Class 4	Class 4	Class 4	Class 4	Class 4

4.4.1 Class 2 Estimate Development

IPL employed the help of several engineering firms to complete the detailed engineering for Year 1 and Year 2 Projects. IPL created project scope statements for each project and worked closely with the engineering firms through the design process to ensure the design matched the scope. Class 2 estimates were developed by completing individual project detailed engineering. The total project costs were estimated by the engineering firm assigned to the project. IPL worked with B&V to create a uniform method of developing and presenting the Class 2 estimates. IPL subject matter experts in each discipline worked with the various engineering firms to ensure conformity to the uniform method of developing Class 2 estimates. There is no retirement or maintenance cost included in the Class 2 estimates.

For the CBD Secondary Network Upgrades, Static Wire Performance Improvement, Substation Assets Replacement, Remote Ends – Breaker/Relay Upgrades and Substation Design Upgrades Projects a construction labor bid event was held to determine the labor costs component of the project estimate for Plan Years 1 and 2. For overhead distribution projects and portions of the CBD Secondary Network Upgrades Project, existing contractor unit prices were used. IPL is currently under contract with several vendors that have fixed labor pricing for units of work. IPL leveraged the unit pricing contracts to determine the labor costs for these projects. See Appendix 8.8 for an example of a confidential Class 2 estimate.

4.4.2 Class 3 Estimate Development

Class 3 estimates were developed for XLPE Cable Replacement, Pole Replacements, Steel Tower Life Extension and Distribution Automation Projects using unitized costs. Class 3 estimates were utilized because these project types are low complexity and high-volume projects. The scope of the work is known at a broad level and variation in the scope of work does not drive significant changes in project costs. There is no retirement or maintenance cost included in the Class 3 estimates. For example, the Pole Replacements Project cost estimate was developed based on a wood pole inspection failure rate of 2% for a total of 330 inspection failures annually. The pole replacement cost is based on unitized labor and material rates. IPL estimated the number of pole types (of the 330 average annual failures) that would fail inspection. The estimated individual pole replacement types were then multiplied by the corresponding unit replacement cost. This in turn determined the annual cost of the Pole Replacement Project. Annual variation in the reject rate through the 7- Year Plan is expected. This variation may cause annual variances; however, the Pole Replacement Project cost should normalize around estimated cost of the Project. As poles fail inspection through the life of the TDSIC Plan, detailed engineering will be completed. The cost of these Projects will be updated during the TDSIC annual update as necessary or appropriate. See Appendix 8.9 for an example of a confidential Class 3 estimate.

4.4.3 Class 4 Estimate Development

Class 4 estimates were developed by using unitized costs as well. The unitized costs are parametric or typical costs for similar scopes of work. Class 4 estimates were used uniformly on project costs for Plan Years 3-7. Estimating cost of projects in the later years of the Plan with Class 4 estimates is appropriate due to the uncertainty of future costs and limited scope defined. IPL incorporated the results of the labor costs from the bid events for Class 2 estimates into the Class 4 estimates where applicable. The results of the Class 2 estimates combined with internal subject matter expert judgement on unitizing costs were also incorporated into the Class 4 estimates. There is no retirement or maintenance cost included in the Class 4 estimates. For example, to create a unitized cost to rebuild 1-mile of 3-phase, 13.2 kV distribution line, all the components of a "typical" 1-mile segment of line were identified and itemized. The labor component of the cost was determined by contracted unit pricing and the material cost was derived from IPL's material management system. From this a unitized cost per mile was developed for a "typical" 1-mile section of overhead 13.2 kV distribution. This 1-mile unitized cost was applied to each mile identified in the Risk Model for replacement for years 3 through 7. The cost of these Projects will be updated during the TDSIC annual update as necessary or appropriate. See Appendix 8.10 for an example of a confidential Class 4 estimate.

5 Independent Review of Project Cost Estimates

5.1 Black and Veatch's Independent Review of Project Cost Estimates

IPL engaged B&V to conduct a review of its proposed TDSIC Plan capital cost estimates and estimating process, based on B&V's knowledge and experience with similar capital cost estimates. The review tested estimates for reasonableness based on B&V's experience and the information and backup data received from IPL for its cost estimates.

The specific goals of the independent cost review were:

- To validate that the IPL cost estimating process is in accordance with AACE guidelines; and
- To identify any recommendations for improvement.

B&V's review included IPL's cost estimating process for all projects and an independent estimate verification for a representative sample set of Class 2 project cost estimates from IPL's TDSIC Plan. As part of the review, B&V supported IPL with the development of a uniform method and template for cost estimating to meet AACE Class 2, 3 and 4 guidelines for all project cost estimates. Class 3 and 4 estimate templates completed by IPL subject matter experts were reviewed by a B&V AACE certified estimator for reasonableness. B&V developed independent project estimates for a 5% sample of Class 2 project estimates to verify reasonableness of estimation and completeness of project details.

Black & Veatch's review shows that the IPL cost estimates and cost estimating process are reasonable and consistent with AACE guideline classification. The level of detail IPL used to estimate T&D project cost estimates in its TDSIC Plan is consistent with common practice within the industry. The B&V Cost Estimate Review and Validation Report is included with the IPL TDSIC Plan as Appendix 8.6.

6 TDSIC Project Narratives

6.1 Circuit Rebuilds

Table 6.1.1 – Circuit Rebuilds Project Overview

Project Attribute	Description
TDSIC Activity	IPL will rebuild approximately 406 miles of 3-phase, 13.2 kV overhead distribution lines, on 198 different circuits.
Project Costs[13]	$298.7 million -- capital expenditure.

6.1.1 Background

IPL owns, operates, and maintains transmission and distribution lines located throughout its service territory. The system is essential infrastructure for the safe and reliable delivery of electricity to IPL's customers. The circuit assets evaluated as part of the Circuit Rebuilds Project include wood poles, towers, overhead transmission conductor, overhead distribution conductors and underground cable. Table 6.1.2 provides a summary of the T&D circuit asset base evaluated as part of the Circuit Rebuilds Project.

Table 6.1.2 – Circuit Rebuilds Project T&D Asset Base Summary

Asset Type	Units	Total
Transmission	circuit miles	685
Sub-Transmission and Primary Distribution Overhead (OH)	circuit miles	3,580
Sub-Transmission and Primary Distribution Underground (UG) – Jacketed ONLY	circuit miles	3,278
Total	circuit miles	7,542

Nearly 10 years ago, IPL developed a robust asset management framework and started collecting asset health and consequence information for the more critical assets base (i.e., power transformers and breakers). This effort has proven valuable in managing risk and deploying capital efficiently. As a next step, IPL contracted with BMcD to develop a Risk Model that included

[13] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year detail.

circuit assets. The Risk Model normalized risk across substations and circuits while also providing a methodology to efficiently allocate capital across the T&D system to maximize risk reduction.[14] The Risk Model identified high risk assets and then prioritized replacement based on risk reduced per dollar invested.

IPL used the Risk Model to evaluate the circuit assets at the overhead span level and the underground segment level. An overhead span asset includes a pole and a span of wire connected at the pole up to but not including the next adjacent pole. An underground segment asset includes underground cable between two termination points on the underground system. IPL evaluated circuits at the overhead span and underground segment level using the Risk Model to identify only the portion of each circuit with the highest risk. The high-risk spans and segments were then aggregated at the circuit level and then prioritized for replacement based on overall risk level per mile. Table 6.1.3 shows the results of the Risk Model for the circuit assets in 2026, if no TDSIC investment plan is implemented. Table 6.1.4 shows the results if the IPL TDSIC Risk-Based Scenario is implemented. The counts in each box represent the number of circuit miles in each risk category. This was calculated using the weighted average likelihood of failure and consequence of failure per mile, normalized by circuit length.

Table 6.1.3 – Circuit Heat Map 'Do Nothing' Scenario

		2026 'Do Nothing' Risk Profile Circuit Miles Count (excludes 4kV and Unjacketed Projects)					Total
Likelihood of Failure	Very High - 5	0	0	0	0	[illegible]	0
	High - 4	0	0	0	0	1,337	1,337
	Moderate - 3	[illegible]	0	0	25	3,264	3,289
	Low - 2	[illegible]	1	0	407	2,105	2,512
	Remote - 1	[illegible]	[illegible]	24	0	256	404
	Total	0	125	24	432	6,961	**7,542**
		Very Low	Low	Moderate	High	Very High	
		Consequence of Failure per Mile					

1,337 miles, or 18%, in High-Risk Region.

Table 6.1.4 compared to Table 6.1.3 shows the risk reduction provided by the Risk-Based Scenario. With a targeted approach of 406 miles of replacement on 198 circuits, a comparison of the two tables shows a reduction of 1,215 circuit miles out of the high-risk reduction region. Table 6.1.4 does indicate future investment will be needed with nearly 2,500 miles in the LoF 3 category.

[14] See Appendix 8.3 of IPL's TDSIC Plan for discussion of the Risk Model developed by BMcD and of details regarding the various investments.

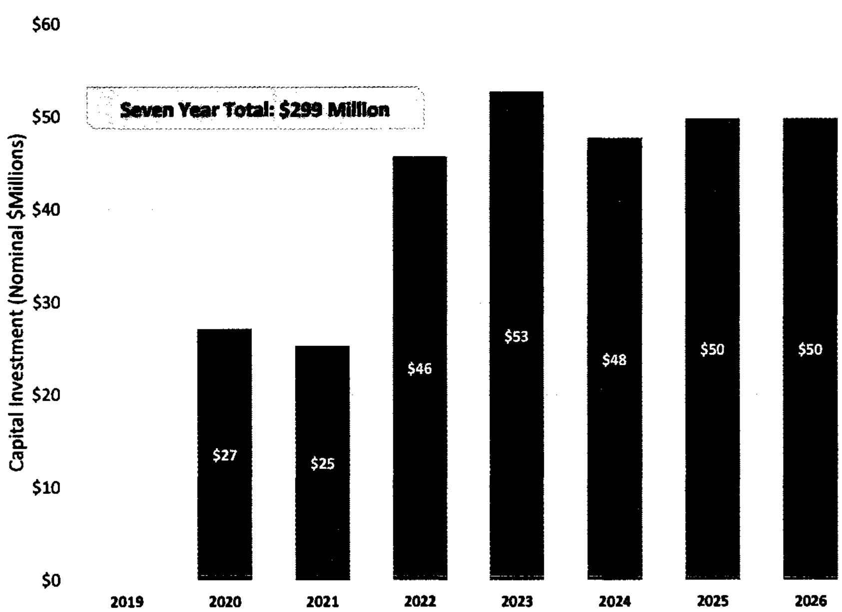
Table 6.1.4 – Circuit Heat Map Post IPL TDSIC Plan

Likelihood of Failure	Investment Plan Risk Profile Circuit Miles Count (excludes 4kV and Unjacketed Projects)					Total
Very High - 5	0	0	0	0	[illegible]	0
High - 4	0	0	0	0	122	122
Moderate - 3	[illegible]	0	0	25	2,494	2,520
Low - 2	[illegible]	1	0	407	3,894	4,301
Remote - 1	[illegible]	[illegible]	24	0	451	599
Total	0	125	24	432	6,961	**7,542**
	Very Low	Low	Moderate	High	Very High	
	Consequence of Failure per Mile					

122 miles, or 2%, in High-Risk Region.

Figure 6.1.1 shows the annual capital investment corresponding to the risk reduction shown from Table 6.1.3 to Table 6.1.4.

Figure 6.1.1 – Circuit Rebuilds Improvement Capital Investment Profile



6.1.2 TDSIC Purposes

The Circuit Rebuilds Project will provide resilience and hardening to the electric distribution system along with modernizing the system to enable distributed energy resources easier access to the grid. This project will also maintain the integrity and safety of the electric distribution system.

6.1.3 Description of Physical Improvements

IPL will rebuild approximately 406 miles of overhead 3-phase 13.2 kV circuit on 198 circuits. These circuits will be rebuilt using a standard 477 ACSR conductor which provides 13% more ampacity and 66% more strength than the existing 397 AAC conductor. Where existing circuits are in difficult access areas the Circuit Rebuilds design will attempt to relocate the circuit to accessible ROWs. During the execution phase, engineering teams will determine if any of the existing assets meet the current design standard. If they do, those assets will not be replaced as part of the Circuit Rebuilds Project.

6.1.4 Benefits of Circuit Rebuilds Project

The Circuit Rebuilds Project will provide the following benefits:

Safety

By replacing aged and deteriorated circuit assets IPL will be better positioned to maintain and operate a safe electrical system. By systematically and proactively replacing these assets IPL avoids the consequences associated with these asset failures. This in turn makes the IPL electric system safer for the public and IPL employees.

Improved System Hardening

Rebuilding high risk overhead spans will make the electric system stronger. Existing overhead spans will be replaced with stronger and taller poles and will have larger and stronger conductors. This means fewer broken poles and wires during weather events. This in turn improves reliability.

Improved System Resiliency

While outages will still occur during weather events, with fewer broken poles and wires the electric system becomes more resilient. Restoring power is quicker with fewer broken poles and wires. This in turn decreases the duration of interruptions of service, improving system reliability.

Enables Distributed Energy Resources

By rebuilding with larger current carrying capacity conductors, the IPL electric distribution system will be able to onboard more distributed energy resources with reduced impact to the electric system. As more distributed energy resources are added to the electric system, larger current carry capacity will be needed for bi-directional load flow on the distribution system.

Reduces System Risk

The Circuit Rebuilds Project lowers overall system risk on the IPL electric system by lowering the likelihood of assets failing and the associated consequence of the failures.

6.1.5 Summary

The Circuit Rebuilds Project will enhance system reliability, help maintain system safety along with enabling the modernization of the energy delivery system. The combination of these impacts reduces the overall system risk of the electric system.

6.2 Substation Assets Replacement

Table 6.2.1 – Substation Assets Replacement Project Overview

Project Attribute	Description
TDSIC Activity	IPL will replace high risk assets at 70 of IPL's transmission and distribution system substations. The work includes the replacement 11 power transformers, 560 breakers, and 60 batteries, for a total of 631 major substation assets.
Project Costs[15]	$248.1 million -- capital expenditure.

6.2.1 Background

IPL owns and maintains a large fleet of T&D substations located throughout its service territory. The substations are essential infrastructure for the safe and reliable delivery of electricity to IPL's customers.

To manage these and other assets, over the last decade IPL has been developing an asset management framework and program. As part of this framework and program, IPL developed asset health scores to assess the condition of power transformers and breakers. Additionally, IPL created consequence scores for these assets. IPL deployed data collection technologies and built the IT infrastructure to collect, store, and assess this asset health and consequence information. IPL has leveraged the asset health data to target conditioned based maintenance. With this asset management practice in place, IPL has been able to extend the expected average service lives of the substation asset.

As a next step, IPL contracted with BMcD to further develop a Risk Model that included 217 power transformers, 1,359 breakers, and 114 batteries for a total substation asset count of 1,690. [16]

Relevant to this Project, the Risk Model identified high risk assets and then prioritized replacement based on risk reduced per dollar invested. As explained below, the Substation Assets Replacement Project replaces the substation transformers, breakers and batteries identified as High Risk of failure in the BMcD modeling.

Table 6.2.2 shows the results in 2026 of the Risk Model for the substation assets if no TDSIC investment plan is implemented. Table 6.2.3 shows the results of the Risk Model if the IPL TDSIC

[15] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.
[16] See Appendix 8.3 of IPL's TDSIC Plan for discussion of the Risk Model developed by BMcD and of details regarding the various investments.

Risked-Based Scenario is implemented. The counts in each box represent the number of assets with the associated likelihood and consequence of failure. Table 6.2.2 shows, 19 percent of the substation asset base is in the high-risk region (outlined in red) where assets have a high and very high likelihood of failure with a high and very high consequence of failure.

Table 6.2.2 – Substation Heat Map in 'Do Nothing' Scenario[17]

		2026 'Do Nothing' Risk Profile: Asset Count (excludes 4kV conversion and remote end breaker assets)					Total
Likelihood of Failure	Very High - 5	0	1	2	8	[illegible]	134
	High - 4	0	0	1	57	102	160
	Moderate - 3	[illegible]	6	3	203	267	479
	Low - 2	[illegible]	7	1	119	108	236
	Remote - 1	[redacted]	[illegible]	8	232	244	487
	Total	1	17	15	619	844	1,496
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
		Consequence of Failure					

290 assets, or 19%, in High-Risk Region.

Table 6.2.3 – Substation Heat Map in IPL TDSIC Scenario[18]

		2026 Investment Plan Risk Profile: Asset Count (excludes 4kV conversion and remote end breaker assets)					Total
Likelihood of Failure	Very High - 5	0	1	0	0	[illegible]	1
	High - 4	0	0	1	0	0	1
	Moderate - 3	[illegible]	6	3	90	87	186
	Low - 2	[illegible]	7	2	116	146	271
	Remote - 1	[redacted]	[illegible]	9	416	608	1,037
	Total	1	17	15	622	841	1,496
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
		Consequence of Failure					

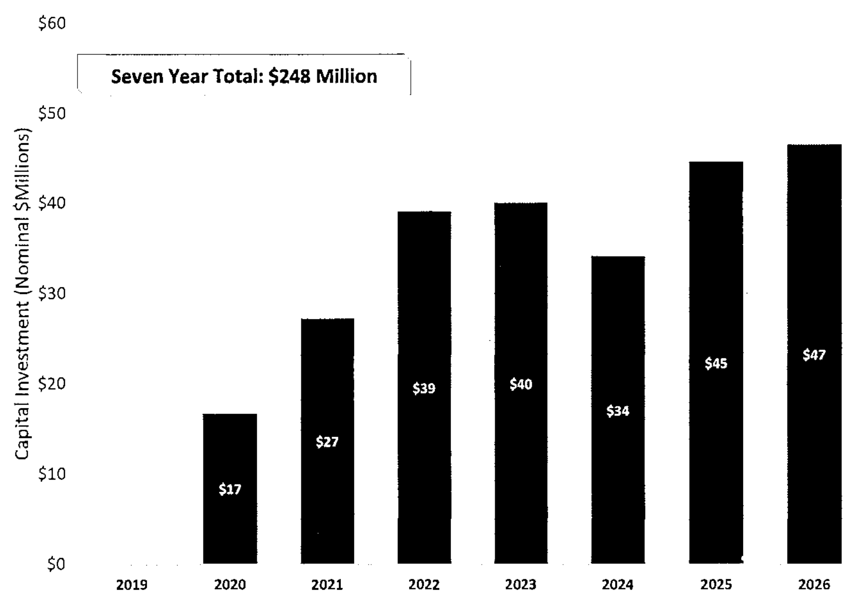
0 assets, or 0%, in High-Risk Region.

Table 6.2.3 shows the risk reduction provided by the IPL TDSIC Scenario. Table 6.2.3 shows no assets in the high-risk region and only 2 low consequence assets with a high or very high likelihood of failure. Additionally, the table indicates continuous future investments will be needed. For example, over time assets in the moderate LoF category will move into the high-risk

[17] This is a modification of Figure 1-2 from the Burns & McDonnell Report to exclude the 4 kV conversion and remote end breaker assets.
[18] This is a modification of Figure 5-8 from the Burns & McDonnell Report to exclude the 4 kV conversion and remote end breaker assets.

region. IPL's strategy to manage the risk of the 188 assets is continuous monitoring of asset health data and preventive maintenance. Figure 6.2.1 shows annual capital investment corresponding to the risk reduction show from Table 6.2.2 to Table 6.2.3.

Figure 6.2.1 – Substation Assets Replacement Capital Investment Profile[19]



6.2.2 TDSIC Purposes

This Substation Assets Replacement Project meets TDSIC purposes in two ways. The key purpose is to address aging substation infrastructure by targeting capital on high risk substation assets. By proactively replacing high risk assets IPL will improve safety and system performance. By replacing the identified high-risk assets with new modern equipment, IPL will move to a more enabled and modern electric system.

6.2.3 Description of Physical Improvements

The Substation Assets Replacement Project includes replacement of 11 power transformers, 560 breakers, and 60 batteries at 70 different substations. Of these replacements, 477 of the 560 breakers are metalclad medium voltage switchgear type and the remainder being open air breakers. The replacements will be performed over a seven-year period. See Appendix 8.7 for year by year project detail.

[19] Adaptation of Figure 5-7 of the Risk Model Report to exclude circuits, remote end breaker and relays, and 4 kV conversion.

6.2.4 Benefits

This Substation Assets Replacement Project will provide various benefits as described below:

Reduce Substation System Risk

The substation assets identified for replacement by the Risk Model will improve overall system performance and reduce risk by making substations more safe, reliable and efficient while modernizing the grid.

Replaced Assets Will Be Modernized

Breakers - Breakers will be replaced with newer technology. The new breakers will have higher fault current interrupting and increased load current carrying capabilities with microprocessor relaying. Breakers that are part of metal clad switchgear replacement will be equipped with remote racking. The new microprocessor-controlled relays provide advanced protective schemes capabilities, system event forensic information and advanced monitoring and control of the breaker.

Power Transformers - New power transformers will be equipped with continuous Gas Analysis monitoring. This monitoring provides higher resolution on the health of the power transformer allowing IPL to take corrective action sooner, avoiding potentially damaging the transformer.

Station Battery – New station batteries will have increased capacity for operating digital relays. They will be equipped with improved protections schemes and have continuous, hydrogen monitoring.

Reduced Maintenance Cycles – The new modern substation equipment has longer durations between maintenance cycles relative to the existing equipment.

6.2.5 Summary

The Substation Assets Replacement Project replaces the highest risk substation assets in IPL's energy delivery system. By replacing and modernizing IPL's assets in this category, IPL will enhance its ability to operate and maintain the Bulk Electric System and the distribution system more safely and reliably. These substation improvements play a major role in reducing IPL's total system risk.

6.3 XLPE Cable Replacement

Table 6.3.1 – XLPE Cable Replacement Project Overview

Project Attribute	Description
TDSIC Activity	IPL will replace or extend the life of approximately 3.6 million feet (686 miles) of existing Cross-Linked Polyethylene (XLPE) type cable that serves predominately residential distribution service areas. Existing XLPE type cable will be tested to determine whether it is capable of being injected with a healing fluid to extend its life 25 years. If the cable is not able to be injected it will be replaced with a longer life Ethylene Propylene Rubber (EPR) type cable.
Project Costs[20]	$86.2 million -- capital expenditure.

6.3.1 Background

The XLPE type cable is predominately buried within utility easements, underneath streets, alleys, sidewalks, and backyards. The cable has an exposed neutral conductor wound overtop a protective semi-conducting shield that covers the electrical insulating material. Since its initial installation, the XLPE cable has been prone to premature failure due to insulation break down from water exposure. As such, this cable has a poor performance record on the IPL distribution system. XLPE cable failures cause customer power outages and costly emergency repairs.

High failure rates of XLPE type cable is a utility industry issue not unique to IPL. Utility best practices for addressing the high failure rates of XLPE type cables can be described as a two-tiered approach. First, the cable is assessed to determine if it can be injected with a healing fluid that enables the XLPE insulation to regain its strength. If the cable can be injected, the healing fluid extends the life of the cable 25 years at a much lower cost than replacing the cable.[21] Second, if after the assessment the cable is determined not to be a candidate for injection, the cable is replaced.

IPL has been using this two-tiered approach to address XLPE failure rates since 2011. From this experience XLPE has seen a cable injection rate of 40%, meaning that after the assessment, 40% of the cable is capable of being injected, avoiding the higher cost replacement alternative. This acceptance rate is used to calculate the overall cost of the XLPE Cable Replacement Project.

[20] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.
[21] For further information on injection of cable to extend its life see http://www.novinium.com.

Figure 6.3.1 - High Failure Rate XLPE URD cable

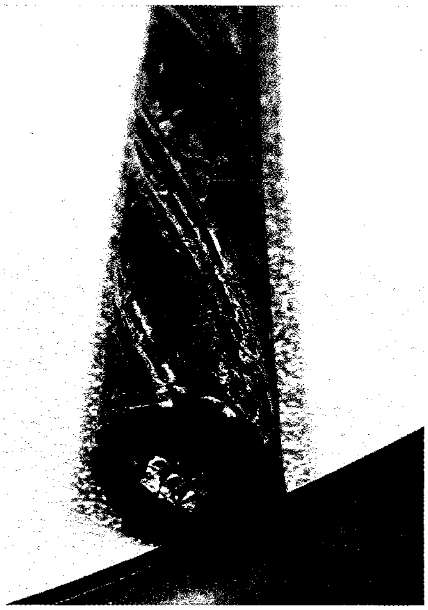
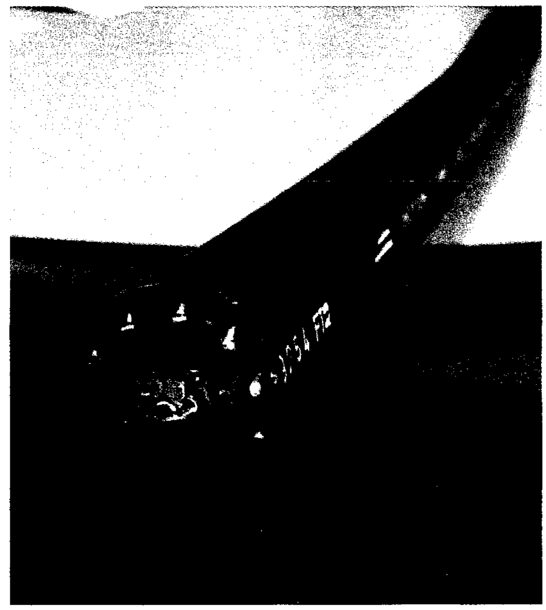


Figure 6.3.2 - New EPR cable with 45-50-year life



6.3.2 TDSIC Purposes

The XLPE Cable Replacement Project meets TDSIC purposes by improving reliability to customers served from the cable targeted for injection or replacement. The replacement cable is a modern cable design using EPR insulation that has a life expectancy of 45-50-years. The EPR replacement cable will provide long term reliability during this period. Fewer cable failures also means less time spent locating and isolating faulted sections of cable, reducing operational costs. Fewer faults result in improved safety because there will be fewer excavations associated with faulted cable repairs, often in difficult field conditions.

6.3.3 Description of Physical Improvements

IPL has knowledge of the specific locations of the high failure rates on existing XLPE cable from its outage management system. In the first years of the plan, high priority areas with elevated failure rates will be targeted. Along with the high priority targeted approach, IPL will address cable injection/replacement from a system wide review of the remaining service territory to avoid future failures from occurring.

For cable replacement, IPL will use horizontal directional boring methods along with hydro-vac trucks for pot holing. Open excavations will be kept to a minimum. These methods are recognized by Common Ground Alliance (CGA) as best practices in the utility industry.

6.3.4 Benefits

The following benefits are associated with this XLPE Cable Replacement Project:

Reliability Improvement

By replacing or injecting 3.6 million feet of XLPE cable, IPL will experience fewer permanent fault conditions. This will improve customer reliability by lowering the number of outages experienced.

Less Unplanned Work

Reducing cable faults reduces the need to dispatch qualified electrical workers and equipment to restore power.

Safety

Because there will be fewer field repairs, IPL employee and public safety risk is improved.

Risk Reduction

Replacement of the XLPE cable with new EPR cable lowers the risk on the distribution system and is part of the overall risk reduction score calculated by the Risk Model.[22]

6.3.5 Summary

IPL's XLPE Cable Replacement Project identifies deteriorated XLPE cable on the electric distribution system and replaces or injects it. This Project will improve service reliability for customers served directly from the circuits with XLPE cable.

[22] See IPL's TDSIC Plan Appendix 8.3 for Risk Model Report.

6.4 4 kV Conversion

Table 6.4.1 – 4 kV Conversion Project Overview

Project Attribute	Description
TDSIC Activity	IPL proposes to convert its remaining 4 kV general distribution circuits[23] and associated infrastructure to 13.2 kV. The current 4 kV system serves approximately 14,420 residential and small commercial customers in the north and northeast side of the Indianapolis downtown.
Project Costs[24]	$92.0 million – capital expenditure.

6.4.1 Background

Approximately 14,420 (3%) of IPL's residential and small commercial customers are served by IPL's increasingly obsolete 4 kV distribution system. The 4 kV system was installed during the 1940s and 50s. At the time, it was a reliable and cost-effective distribution primary voltage standard. Portions of the service area served by the 4 kV system are experiencing a revitalization of residential and commercial properties. Over the last three decades, IPL has converted most of the 4 kV system, upgrading it to the current standard 13.2 kV primary voltage. When the 4 kV load is converted to 13.2 kV it is tied into a larger distribution network with many different paths for service restoration. The remaining 4 kV system is isolated from the broader 13.2 kV system. The isolation of the 4 kV system combined with condition of the substation and distribution equipment puts the load served from the 4 kV system at an increased risk of sustained outages.

6.4.2 TDSIC Purposes

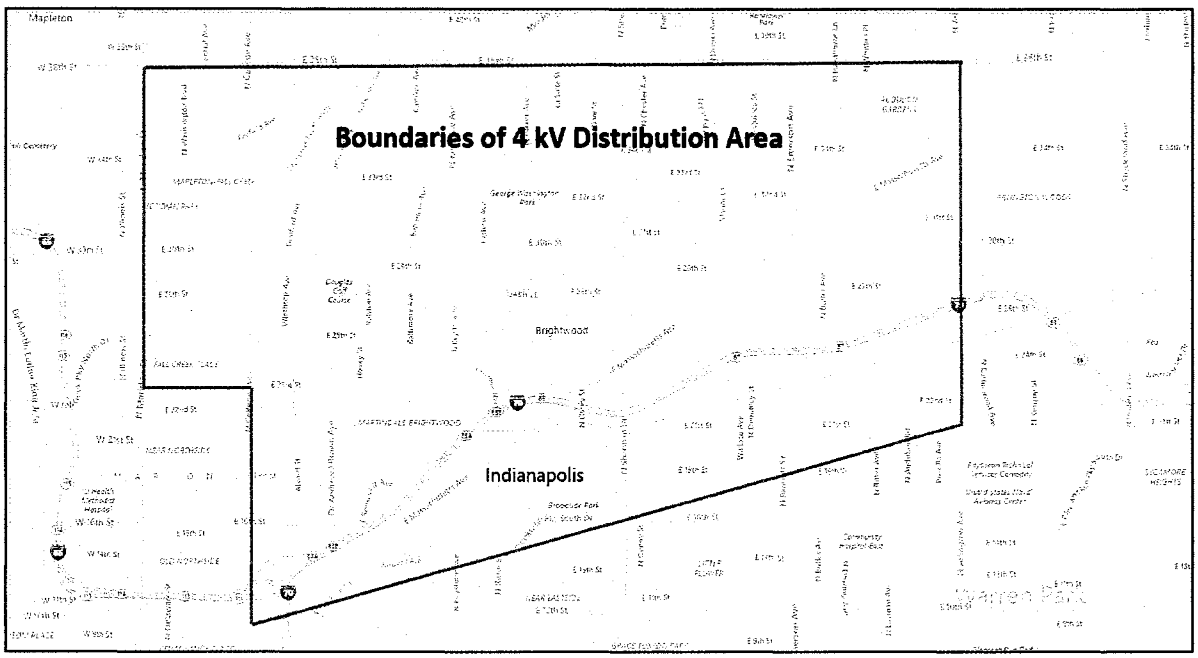
The initiative aligns well with TDSIC purposes of safety, reliability and system modernization. IPL will address these criteria by eliminating an increasingly obsolete portion of its distribution system that is challenging to maintain. Many spare parts for the 4 kV substation equipment are no longer available. Converting the existing 4 kV circuits to 13.2 kV operation modernizes the electric distribution system to standard equipment used throughout the IPL system. Also, converting the 4 kV system to 13.2 kV operation will provide the needed capacity required for the neighborhood revitalization and contribute to local and regional economic development.

[23] The industrial customers receiving service at 4 kV are isolated from the general distribution 4 kV system and are not included in the TDSIC 4 kV Conversion Project.
[24] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

6.4.3 Description of Physical Improvements

IPL proposes to convert its remaining 4 kV distribution circuits, which serve the north and northeast side of the Indianapolis downtown. The approximate boundaries of the impacted area are I-65/I-70 loop on the south, Boulevard Pl. on the west, 38th St. on the north and Arlington Ave. on the east. This area measures at approximately 15 square miles and is depicted in Figure 6.4.1 below.

Figure 6.4.1 – 4 kV Conversion Project Area (~ 15 square miles, 14,420 customers)



The project work involves the following:

- IPL will rebuild 45 4 kV distribution circuits -- representing 393.5 conductor miles. These circuits will be built to today's 13.2 kV standards.
- Sixteen 34.5/4 kV substations will be retired.
- IPL will construct a new 138/13.2 kV substation to provide the needed circuit capacity for the proposed 4 kV conversion and to provide capacity for future growth. The new substation required for the conversion of the 4 kV load to the 13.2 kV system is considered under the Deliverability – Substation Design Upgrades portion of the plan.

6.4.4 Benefits

Conversion of the 4 kV system has the following benefits for the IPL system and IPL customers.

Replacing Obsolete and Aged Equipment

The remaining 4 kV system obsolete and is difficult to maintain. Converting the 4 kV system to 13.2 kV operation will bring the system up to current design standards and will allow for a common single voltage distribution network.

More Efficient Distribution Voltage

Converting the 4 kV system to 13.2 kV operation allows more load to be served in the area. The 13.2 kV system can deliver over three times the amount energy as the 4 kV system can with the same facilities in place. Also, line losses at 13.2 kV are nine times less than they are at 4 kV.

Incorporates the 4 kV Isolated Load Into the 13.2 kV System

Converting the 4 kV system to 13.2 kV operation provides access, to the existing customers served from the 4 kV system, to the larger 13.2 kV network that provides enhanced switching capabilities for outage contingencies and more interconnection opportunities in the future.

Retire Sixteen 4 kV Substations

By converting the 4 kV load IPL will be able to retire 16 old 4 kV substations and combine them into one new modern 13.2 kV substation.

6.4.5 Summary

In summary, the 4 kV Conversion Project addresses an important yet persistent pocket of aging infrastructure, which is experiencing increasing reliability and operational concerns as it ages and deteriorates. The conversion to 13.2 kV supports economic development and provides system modernization benefits such as maintenance efficiency, improved safety, performance risk, and line loss reduction.

6.5 Tap Reliability Improvement Projects

Table 6.5.1 – Tap Reliability Improvement Projects Overview

Project Attribute	Description
TDSIC Activity	IPL will improve reliability on distribution overhead fused tap lines that underperform. System improvements on identified tap lines will be achieved through conversion to underground, equipment replacement, reconfiguration and other methods. This Project will substantially improve the reliability for IPL customers served by the identified tap lines.
Project Costs[25]	$76.5 million -- capital expenditure.

6.5.1 Background

Utility primary distribution circuits consist of main line feeders with numerous lateral lines that are tapped from the main line. These tap lines often serve a small portion of customers and have fuses to isolate each tap line from the main feeder. The fuse disconnects the tap from the main line feeder and limits the customers without power to only those on the tap line when faults occur on the tap line. Some overhead tap lines experience a higher number of interruptions due to adverse weather and interference caused by the surrounding environment such as animals, equipment, and trees. Customers on these taps generally experience more power outages than other IPL customers. These overhead taps generally serve older, established residential neighborhoods. Further, years of gradual fence placement, vegetation growth, and other development often make these overhead taps difficult to access. Difficult access increases repair difficulty, potentially extending the duration of interruptions when they occur.

Each tap is unique having a different mix of outage causes, configuration and physical condition. Reliability can be improved by identifying and assessing taps with a higher number of outages and implementing measures to improve the tap line performance.

6.5.2 TDSIC Purposes

Consistent with TDSIC requirements, this is a distribution project to improve reliability and safety. The primary purpose is to reduce the number of sustained outages on poor performing overhead fused taps. The project improves safety by reducing the potential for interference with the 7.6 kV overhead lines. The project also reduces line repair and clearance costs.

[25] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

6.5.3 Description of Physical Improvements

Every 12 months, IPL will select a candidate list of tap lines based on the previous 36 months of historical performance for number of events and impact on customers. IPL will evaluate improvement options and generate a list projects to be worked for the following year. For TDSIC Plan Year 1, twenty improvement projects have been identified based on this criterion at an estimated cost of approximately $10.5 million. For the remaining six plan years, approximately $10 million has been allocated to address tap lines and the specific improvements will be made based on historical performance as noted above. Taps with the worst performance will naturally have the higher priority. Reliability improvement treatment will be applied as appropriate to all lines downstream from the selected tap point.

IPL will use a variety of methods to improve reliability on these tap lines. Some will have replacement of older equipment such as cross arms, self-protected transformers, surge arresters and insulators with new equipment. A few may be reconfigured to reduce exposure. Many overhead taps will be converted to underground.

For those fused taps that are candidates for converting from overhead facilities to underground, IPL will find suitable routes for the cable and find appropriate transformer service locations.

6.5.4 Benefits

IPL's Tap Reliability Improvement Projects targets taps prone to reoccurring outages. Because this Project addresses the underlying outage causes this Project provides reliability benefit for the affected overhead taps.

Safety

Overhead taps that are converted to underground reduce the potential for the overhead facilities to be exposed to environmental factors, such as animals, public, and trees. Also, replacing older equipment reduces the probability of failure.

Reliability

IPL customers on these tap lines will see a significant improvement in reliability. For example, consider the work plan for 2020. The twenty tap lines in the 2020 plan cause 59 outages per year with an average duration of 8.9 hours per event. They account for 331 outage incidents for years 2016, 2017, and 2018. On average, about 75% of the outages caused by these tap lines will be eliminated.

Direct Repair and Maintenance Savings

Overhead tap outages are expensive to repair and contribute significantly to expenses. On average the cost per incident is about $3,000. This generates future direct savings of over $331,000 per year assuming an 75% improvement. The estimated future savings for line clearance is $43,300 per year.

Customer satisfaction

Frequent long-duration outages are a major source of dissatisfaction and complaints. This project will significantly improve the experience of customers that have historically been most impacted by these types of outages.

6.5.5 Summary

In summary, IPL's Tap Reliability Improvement Projects satisfies TDSIC requirements. It improves safety and reliability. It offers substantial reliability value to customers and will reduce upward pressure on operating costs which would otherwise be expected to increase as facility failures increase.

6.6 Meter Replacement

Table 6.6.1 – Meter Replacement Project Overview

Project Attribute	Description
TDSIC Activity	IPL will replace approximately 350,000 residential and small commercial single and three phase electric meters over a five-year period beginning in 2020. The planned deployment rate is approximately 5,833 per month.
Project Costs[26]	$55.9 million -- capital expenditure.

6.6.1 Background

In 1997, IPL began moving toward an Automatic Metering Reading (AMR) system. This represents a first generation of meter automation but today it is a legacy system. IPL implemented the AMR technology by retrofitting its existing electro-mechanical meters with an AMR communication module. The AMR module counts meter dial rotations and then communicates this information to collectors in a one-way communications mode. The AMR communications module was installed with an expected average service life of 20 years. As a practical matter, this means that some meters will fail before 20 years while others will continue operation to or beyond the 20-year mark.

In 2013, IPL began to upgrade the AMR network to accommodate Advanced Metering Infrastructure (AMI) meters. The AMI meter is much different than the AMR meter, as the communications is integral to the meter (versus the AMR retrofit approach), and it comes equipped with a connect/disconnect switch and other advanced metering functions (like voltage measurement). The AMI migration effort began with an update to the communication system to enable it to read both types of meters. This prudent investment laid the foundation for transitioning to the next generation of automated meter technology as the AMR technology reached the end of its useful life.

By 2013, IPL was experiencing an increase in AMR communication module failures. With an updated meter communications network in place, IPL started swapping failing AMR-equipped meters with an AMI meter. IPL's recent practice has been to change the meter when it failed and when the site was visited for another purpose, such as a "last read" trip meter read when a residence was being transferred to a new owner. Because these meter swaps are reactive in nature and the timing or location of their occurrence cannot be predicted, the AMI meters are

[26] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

scattered throughout the IPL service territory. As of December 31, 2018, 144,000 of IPL's original AMR meters are now AMI-equipped.

Since 2013, the average annual AMR-equipped failure rates have doubled from less than 1% in 2013 to over 2% in 2018. The increasing failure rate reflects the AMR modules reaching or exceeding the expected average 20-year service life. To put perspective around meter failures, during the last two weeks of October 2018, IPL detected 360 AMR-equipped meters failed to communicate with the network and thus required a replacement on an expedited basis. An emergent increase in the work load like this presents challenges and inefficiencies.

As the AMR population ages and the number of meters exceeding the 20-year expected service life grows, IPL reasonably expects the AMR failure rate will increase beyond 2018's 2% level. The increasing failure rate poses a risk to the operation of the distribution system and the customer experience. Addressing this increasing risk in a proactive manner is more efficient than addressing it through reactive, unplanned trips. The proactive replacement of the remaining AMR meters as part of the TDSIC Plan mitigates the risk of AMR failures and allows the operational and other benefits of AMI technology to be secured in a timely manner.

6.6.2 TDSIC Purposes

This Meter Replacement Project meets TDSIC purposes in several ways. By proactively completing the migration to advanced metering, IPL will modernize its electricity delivery system and provide operational and other customer benefits while avoiding the negative effects of the increasing AMR-equipped meter failures.

The Meter Replacement Project will improve safety. With AMI meters, IPL is able to more safely connect, disconnect and reconnect customers (without, for example, entering customer back yards). Field trips – and related vehicular travel – will be reduced significantly. Theft and tamper circumstances (involving theft of power, usually in unsafe ways) can be more quickly detected and resolved.

The completion of the AMI migration will improve the IPL distribution system operation and reliability. For example, meter-provided equipment loading diagnostics will allow IPL to proactively detect potential equipment malfunctions, such as transformer overloads. AMI will also improve IPL's outage response capabilities in response to isolated incidents, (also known as "blue sky" "single lights out" conditions) as well as during major storm outage conditions.

6.6.3 Description of Physical Improvements

IPL will procure, test, program and install approximately 350,000 advanced, two-way communicating single phase and three phase meters from a leading meter manufacturer. These meters will be deployed to IPL's residential and small commercial customers using existing processes already in place.

6.6.4 Benefits

IPL made the prudent decision to enable its network to read AMI meters for the purposes of migrating from AMR to AMI, which provides the next generation of automation benefits as described below:

Engineering and Distribution System Operational Benefits

AMI improves the utility with new monitoring and diagnostic tools, which help the IPL distribution engineers manage the grid more effectively. For example, the AMI meters provide the means to monitor the health of electric power distribution network equipment (such as transformers, capacitor banks, electrical connections, voltage conditions, power harmonics).

AMI, for example, can help IPL verify meter wiring configurations, can help predict distribution transformer loading (and potential for overloading and therefore the risk of damage), and can monitor voltage sags and swells with changing circuit conditions. This type of information helps the distribution engineer address circuit problems proactively and leads to improvements to the customer's power quality and reliability.

Finally, deployment of the AMI meters will facilitate the interconnection with customer sited Distributed Energy Resources ("DER") such as electrical vehicles, solar and wind.

Distribution Outages Benefits

AMI meters also provide significant benefits to outage management functions. The meters' 'last gasp' notices (upon loss of power) and restoration signals (when power is restored) provide valuable information to IPL's Outage Management System ("OMS"). This improves IPL's ability to understand the extent of outages and manage the restoration work during major outage events. The signals integrated into the IPL OMS improves service reliability, and greater levels of customer satisfaction.

Avoidance of AMR-related Meter Failure Costs and Risks

As stated above, by proactively replacing the AMR-equipped meters, IPL mitigates the increasing risk of AMR meter failure. Furthermore, as the level of failures grows, the complexities of managing the work also increases, particularly when the emergent work must be addressed within a compressed timeframe. There are cascading impacts as the level of urgent repair work grows and other routine work is deferred to allow the emergent work to be addressed.

Reduced Field Trips for AMR Meter Maintenance

IPL experiences a certain volume of field trips to AMR-equipped meters due to age-related failure and poor performance. The AMI system performs to a higher level of performance across the communications network and as part of the meter itself. Therefore, the number of meter maintenance field trips is expected to decline with fully implemented AMI. This cost will be reduced with AMI because this system is known generally to achieve a higher degree of monthly and daily read reliability and this is IPL's experience to date with its AMI system.

Reduced Field Trips for Disconnect and Reconnect Purposes

The AMI meter is equipped with an internal switch that can be activated and controlled over the communications system. Therefore, IPL's expansion of AMI meters will increase the automation of the distribution system and can reduce field meter service-related trips involving the disconnection and reconnection of meters. These may include trips when a customer is moving into or out of a residence. IPL also makes trips to the customer location to disconnect service for nonpayment and related reconnection of service once payment is made. The AMI automation can improve the efficiency of this process and lead to reductions in operating costs. The automated switch allows the field representative to perform the work more safely and quickly, thus making the trip more efficient. A reduction in the nature and number of site trips is expected to reduce the ongoing cost of this work. While IPL will continue to comply with IURC regulations regarding the disconnection to service, based on current field trip activity levels, IPL estimates that it will be able to re-assign six Metering Division field technicians to other responsibilities once AMI is fully installed.

It should be noted as well that these reductions in field trips reduce Metering Division costs for support equipment, vehicles, fuel, uniforms and other supplies. Also, of relevance is the improvement in safety to the customers and IPL's field workers who are no longer required to enter backyards and other locations to secure a last billing read or physically disconnect the meter.

Customer Care Benefits

AMI provides numerous benefits in the support of many customer care functions. AMI meter data is more granular than what is provided across the AMR meter network. With AMI, meter reads are available at daily, hourly, and sub-hourly levels of detail. This granular consumption information can help IPL's customer care agents assist customers more effectively when they inquire about their electricity use patterns and bills. This in turn should support ongoing customer satisfaction with their service.

The improved and more granular meter data also provides the foundation for customers to have better information about their energy use patterns and energy efficiency efforts. The two-way communications capability of the AMI meter system means that the IPL can automate the service reconnection process and thus allow timely (~ < 1 minute) reconnection of service following notice of bill payment. This can reduce the need for the customer to call the customer care center to inquire as to when service will be restored and thus reduce customer inconvenience (as the customer is provided with a fast fulfillment and restoration of the service upon payment).

Because IPL can remotely 'ping' the AMI meter, customer care representatives can often help a customer determine the power status of the meter. Customers sometimes call IPL inquiring about the loss of power in their homes, and this information can help troubleshoot whether the loss of power is on the customer-side (where the customer is responsible for arranging an electrician to troubleshoot the issue) or utility-side of the meter (where IPL is responsible for resolving the issue). This allows the customer to be informed of the nature of the service issue and avoids the cost of and time associated with an unnecessary field trip if the loss of power is on the customer side of the meter.

The completion of the AMI system will provide the foundation for new customer benefits which facilitate the provision of electricity to new and emerging technologies. The benefits of AMI justify the Meter Replacement Project when considering the full extent of AMI technology and the avoidance of AMR meter failure risks (as the AMR population ages, failure rates increase). Accelerating deployment of AMI in accordance with the Meter Replacement Project allows overall AMI benefits to be achieved sooner than the existing normal replacement plan. Further benefits are quantified in the below table.

Table 6.6.2 – AMI Meter Acceleration Benefits

AMI Meter Deployment Estimated Benefits Achieved Sooner with an Accelerated Plan		
Description	**Benefits**	
Accelerated Reduction in Metering Personnel	$	3,394,417
Savings Associated with Programmatic Replacement (Contractor dedicated to pro-active replacement)	$	11,550,000
Cost Reduction in Visits for Reconnects	$	2,662,200
Net Benefits of Accelerated Plan	**$**	**17,606,617**

6.6.5 Summary

In summary, IPL's Meter Replacement Project mitigates the risk of a reasonably expected increase in urgent meter replacements due to failed or failing AMR meters. The Meter Replacement Project enables the delivery of system operational and engineering benefits as well as customer care benefits made possible through the operation of an advanced metering network.

6.7 CBD Secondary Network Upgrades

Table 6.7.1 – CBD Secondary Network Upgrades Project Overview

Project Attribute	Description
TDSIC Activity	IPL will relocate targeted manhole and duct bank facilities, replace 15 kV feeder cables, 208 V network protectors and network transformers and install vault monitoring technology. IPL also plans to enhance the network System Controls and Data Acquisition ("SCADA") system and expand Distributed Temperature Sensing ("DTS") technology and add Distributed Acoustic Sensing ("DAS") technology to assist in monitoring and responding to potential network events. The combination of upgrades, rebuilds and replacement of equipment will improve safety, reduce the likelihood of network events and enhance operations.
Project Costs[27]	$39.0 million -- capital expenditure.

6.7.1 Background

The IPL underground secondary network is a complex system of transformers, network protectors and control equipment. This complex system is interconnected by primary, secondary and communication cables which are routed through underground duct lines, manholes and vaults. The secondary network is contained within a "Mile Square" area and is geographically located between North, South, East and West Streets in the Central Business District (CBD). There are approximately 625 miles of duct lines, 1,214 manholes and 140 network vaults in the secondary network area.

The environment in which the IPL underground secondary network operates consists of multiple underground utilities, city infrastructure and confined spaces making maintenance and construction difficult. The challenges in operating and maintaining a secondary network are:

1.) known utility conflicts – coordination between IPL facilities with other utility facilities.

2.) unknown utility conflicts - uncertainty of where other utility and obstructions are located.

3.) limited public right-of-way – limited real estate with multiple utilities and other services.

[27] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.8 for cost estimates and year by year project detail.

4.) coordination of work with planned city events – avoiding disruption for high profile events

5.) coordination of work in a vibrant city center – reducing impact on pedestrians, traffic and normal activities.

6.) aged infrastructure and equipment.

6.7.2 TDSIC Purposes

This CBD Secondary Network Upgrades Project meets TDSIC purposes in several ways. By replacing aged assets and relocating targeted assets away from existing heat sources within the secondary network, IPL will improve public and employee safety, reduce the likelihood of system events, and modernize a critical utility system in the heart of the city and thus support economic development.

6.7.3 Description of Physical Improvements

Targeted improvements in the CBD Secondary Network Upgrades Project are:

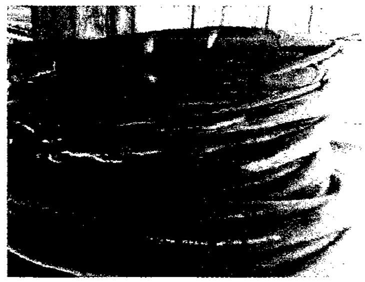
- Relocate and/or rebuild manhole and duct lines
- Replace 15 kV feeder cables
- Replace 208 V network protectors
- Replace network transformers
- Expand DTS technology
- Add DAS technology
- Enhance and expand Network SCADA capabilities

Implementation of proposed improvement plans, and system modernization is expected to better predict asset replacements before failure occurs, therefore reducing frequency of facility failures. The construction will occur over seven years with different components of the plan being spread systematically over the plan years to ensure workability and constructability in the CBD.

Relocate and/or rebuild manhole and duct lines

The Plan includes the relocating and/or rebuilding of (45) manholes and approximately 3,791 feet of duct line. Duct lines and manholes deteriorate over time due to water runoff from buildings and sidewalks. These conditions are not unique to IPL's secondary network system. Replacing duct lines and manholes is challenging. Digging beneath downtown streets may uncover obstacles that are difficult to remove or require an alternate route to be taken. Certain existing infrastructure locations are exposed to risk if left in place (e.g., elevated thermal conditions). Rebuilding or replacing manholes that are small (barrel brick design) will provide more working space for employees who enter them. Manholes targeted for replacement are cramped, have dirt floors with little or no room to work. Newer manhole designs will allow for worker movement and better organization of equipment for ease of access, worker safety and efficiency. Larger manholes also provide space for air circulation to help reduce exposure to combustible gasses. Also, through the strategic replacement and relocation of aged facilities away from underground heat sources there will be less likelihood of cable damage due to the damaging effects of heat. High heat conditions can rapidly deteriorate cable and infrastructure which can lead to a cable failure or breakdown of infrastructure.

Figure 6.7.1 - Two-Year-Old Cable Damaged by External Heat Source



Replace 15 kV cable

The Plan includes the replacement of approximately 48,609 feet of 15 kV primary feeder cable. Replacing poor performing 15 kV cable will reduce primary cable failure. Like many utilities, IPL installed XLPE cable on many of its primary feeders. The material used in the manufacturing of XLPE begins to breakdown prematurely, creating hair-line cracks in the insulation. This effect known as "treeing" allows water and containments into the cable which eventually leads to failure. As this type of cable fails in the IPL secondary network it is replaced with Okonite Okoclear and General Cable PowerNet cables. Proactively replacing the remaining XLPE cable in the secondary network will remove a known poor performing asset from the system. Also, improved public safety will be gained through the installation of low smoke low combustion primary and secondary cable. IPL will replace targeted primary and secondary cables with Okonite Okoclear (primary) and General Cable PowerNet (secondary) to help reduce exposure to combustible gasses.

Replace 208 V network protectors and targeted transformers

IPL will replace twenty-nine 208 V network protectors and thirty-two network transformers. Existing transformers and 208 V network protectors have been in operation for decades and sit in an underground environment. Even with routine maintenance programs some conditions and stresses are not easily detectable. Mechanical equipment operates, wears down over time and becomes less reliable. IPL replaced and upgraded 480 V network protectors to provide a safer work environment for employees. Replacing targeted transformers and 208 V network protectors will upgrade this part of the network system providing improved safety to employees. The new 208 V network protectors will be equipped with an Arc Flash Reduction Maintenance System (ARMS) and a "Stacklight" to indicate the breaker status and ARMS activation. These features will aide in reducing exposure to arc flash potential when working on a network protector.

Modernization of CBD Secondary Network

Modernization of the CBD will include expanding DTS by three fiber routes (approximately 10,000 feet of fiber per route) and adding four routes of DAS technology (approximately 32,000 feet of fiber per route). The innovative technologies helping IPL to modernize the secondary network system are the DTS and DAS systems. These technologies enable IPL to monitor conditions in real-time, pin-point problems and dispatch crews or contact other utilities to evaluate the situation. With fewer secondary network events there will be less overtime expense, fewer cable repairs that become weak points on a circuit and less stress on network equipment from high fault currents. The addition of the DTS routes will cover 100% of the infrastructure which currently cohabitates with heat sources.

DTS

DTS can alarm and locate high heat conditions using fiber optic technology to sense temperature changes (e.g., steam leaks, cable arcing) in duct lines and manholes. Being alerted of these abnormal conditions allows IPL to respond and act to limit or prevent damage to network facilities. Traditional cable fault locating can damage cable as a high DC voltage is applied across the cable to produce a high current and generate a loud "Thump" sound to be detected by field crews. Using DTS and DAS technology (discussed below) can help identify trouble areas and limit the need to thump cable.

DAS

DAS technology also uses fiber optics to listen and pinpoint sound. With the installation of DAS technology, this system will monitor audible disturbances that occur when 15 kV cables fail and locate the audible disturbance on a mapping system. The current method of locating cable failures can often take several hours and can degrade cable depending how long the failure locating process takes. In 2018, a proof of concept installation of the DAS system was successful and determined to have merit.

Enhance CBD Secondary Network System – SCADA System

The IPL plan includes installing (57) VaultGards, (114) water detection devices and (14) RTUs. As part of the vault monitoring technology plan IPL will enhance and expand CBD secondary network SCADA capabilities by adding Remote Terminal Units (RTUs), VaultGards (communication platform) and water level detection. Currently one VaultGard may serve as a communication platform for multiple network vaults making it difficult to trouble-shoot problems and less reliable as the connection between vaults is with twisted copper-pair wires. Adding VaultGards to each vault with fiber optic cable between vaults will reduce connection problems and increase the scan rate across the system allowing data to be transmitted faster. The network SCADA system will also incorporate water level detectors in each vault bay. This vault monitoring technology will provide notification to IPL operators that critical water levels are approaching; an alert system which does not exist today.

6.7.4 Benefits

The CBD Secondary Network Upgrades Project has many benefits for the IPL system and IPL's customers.

Safer and Better Organized Manholes

Considering the network infrastructure, some manholes are very small, barrel brick design, and limit accessibility due to the manhole size. Rebuilding these manholes will not only increase the size but will also allow for the installation of modular splices and racking systems that will improve the efficiency and safety of work being performed in the manhole.

Replacing Aging Infrastructure

Enhancements and upgrades to secondary network material and equipment will reduce the average age of system components within the secondary network system. This will help to make the overall secondary network system more robust and resilient to system conditions and continue to provide uninterrupted data during network events.

Performing at Expected Levels of a Major US City

Continued reliability in the secondary network will build value with businesses and confidence with customers and key stakeholders such as the Indiana Utility Regulatory Commission (IURC), Indianapolis Convention and Visitors Bureau (VisitIndy), City Government and the Capital Improvements Board of Marion County (CIB).

Modernizing Critical City Utility Infrastructure

IPL is applying advanced technologies to the CBD secondary network for increased intelligence of the health of the system, improved operational capabilities and better monitoring and control. The secondary network serves the central business district that drives the economy of Central Indiana. Indianapolis hosts multiple major sporting events and conventions for millions of visitors annually. Modernizing the CBD secondary network system will allow Indianapolis to continue to drive the growth of central Indiana.

6.7.5 Summary

Investing in a plan to modernize, upgrade, rebuild and replace facilities in and supporting the secondary network system will improve safety, reduce network events and enhance operations of the CBD secondary network. This project will allow IPL to better manage, operate and maintain the critical infrastructure that provides electricity to and supports economic development in the City of Indianapolis area.

6.8 Static Wire Performance Improvement

Table 6.8.1 – Static Wire Performance Improvement Project Overview

Project Attribute	Description
TDSIC Activity	This Project will replace approximately 84.3 miles of static wire on IPL's 138 kV transmission system with standard Optical Ground Wire (OPGW).
Project Costs[28]	$62.1 million -- capital expenditure.

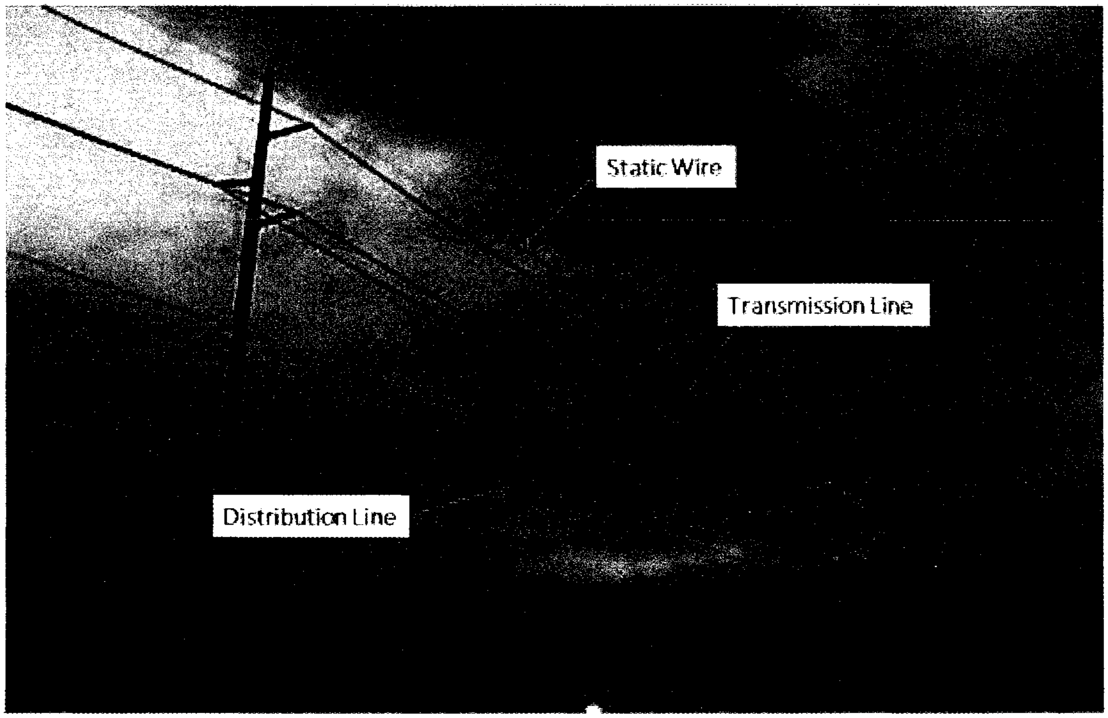
6.8.1 Background

Most overhead transmission lines are designed with a grounded wire at the top of the supporting structures above the phase conductors. This wire, commonly referred to as the "static wire" or "shield wire", is designed to protect the phase conductors from direct lightning strikes by directing the lightning induced current safely to ground. Further, the static wire serves as the return current pathway for fault current during system fault events.

Figure 6.8.1 illustrates the typical single pole transmission line and the location of where the static wire is on the transmission line.

[28] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

Figure 6.8.1 – Static Wire Location



This Project will replace, 68 miles of a specific type of static wire, 3#8 Alumoweld, that was installed on approximately twenty different 138 kV circuits constructed on single-wood poles when they were initially built. This static wire is deteriorated and is performing poorly. When the existing 3#8 Alumoweld static wire fails it falls into the energized transmission and or distribution circuits causing outages. The replacement for this static wire is IPL's current standard OPGW meeting specified outside diameter, strength and fault current capabilities. Since the early 1990s, OPGW has become an economical option for replacing transmission line static wire. The OPGW includes a core of glass optical fibers that provide a telecommunications path between the substations at each end of the transmission line while providing lightning protection for the circuit.

An additional 16.3 miles of existing static wire on the 138-kV system will be replaced with OPGW for improved relay protection. Upgrading the static wire on these lines ensures that the protection equipment on both ends of a transmission line are optimized for efficient, fast, and safe operations. Faults that are cleared faster from transmission lines reducing equipment damage and increases the system reliability and performance seen by our customers. IPL looks at the protection of a transmission line as a system which includes all equipment at both ends of the line.

6.8.2 TDSIC Purposes

This Static Wire Performance Improvement Project meets TDSIC purposes in several ways. This project will improve safety by reducing static wire failures on the IPL system thereby reducing exposing the public to fewer downed wires. The proposed use of OPGW modernizes IPL's electricity delivery system and provides operational and other benefits, such as minimizing the effect of momentary voltage dips (from static wire failures) and improving protective relay and system control and data acquisition (SCADA) communication. The improved relay protection decreases the duration of system faults and this in turn reduces the damaging effect on transmission system components.

6.8.3 Description of Physical Improvements

IPL will design and construct approximately 84.3 miles of static wire replacement on the 138 kV circuits identified below Table 6.8.2.

Table 6.8.2 – Work Plan for Static Wire Performance Improvement Project

Year	Miles	Circuit	Circuit Name
2020	1.73	132-44	Crestview - Northeast
2020	5.27	132-84	Mooresville - Camby
2020	3.75	132-24	MV Tap Switch - Mooresville
2021	3.15	132-35	Pike - Crawfordsville Rd
2021	2.77	132-05	Stout - Glenns Valley
2021	7.79	132-59	Southwest - Sanitation Southport
2021	1.08	132-70	Allison #4 - West
2021	1.21	132-61	Center - Lilly South
2021	1.39	2451-1	Center - Lilly Corp
2022	3.63	132-36	Edison - Brookwood
2022	3.11	132-41	Westlane - Georgetown
2022	4.23	132-28	Prospect - Ford
2023	3.39	132-46	Sunnyside - Geist
2023	1.60	132-51	German Church - Cumberland
2023	7.68	132-43	Guion - Crestview
2024	3.75	132-57	North - River Road
2024	3.05	132-55	Castleton - River Road
2024	5.45	132-52	Cumberland - Ford
2024	0.50	132-50	German Church - Sunnyside
2025	3.05	132-38	Brookwood - Lawrence
2025	2.91	132-49	East - Tobey
2025	2.89	132-68	Tobey - German Church
2025	2.76	132-32	Mill Street - Edison
2026	3.74	132-54	Castleton - Geist
2026	4.36	132-64	Rockville - Allison #4

As reflected in Table 6.8.2, IPL plans to implement this Static Wire Performance Improvement Project evenly over the seven-year TDSIC Plan period based on system protection priorities and will coordinate work on transmission lines with other substation work. IPL will seek to conduct this work in a way that minimizes transmission equipment outage potential.

6.8.4 Benefits

The Static Wire Performance Improvement Project has many benefits for the IPL system and IPL's customers.

Improved Bulk Electric System Performance

Replacing these static wires will improve system-wide performance during fault events by minimizing the number of 138 kV forced outages due to broken shield wire. This will avoid costs associated with emergency repair or replacement of failed static wire.

Safety

Reducing the number of failures has the added benefit of improving employee and public safety. Less static wires that fall in public areas of access minimize the likelihood of inadvertent public contact. Additionally, IPL crews will not have to respond to emergencies to repair downed static wires.

System Resiliency

This Project will add resiliency to the IPL BES by eliminating fault incidents and keeping transmission lines in service during adverse weather conditions.

Enhanced Relay Protection and System Control

Replacing the underperforming static wire with a suitable OPGW conductor provides the ancillary benefit of multiple, additional communication pathways for operating the system and improving relay protection and SCADA system performance. It also provides greater communications redundancy to accommodate various planned or unplanned outages.

Customer Benefits

The completion of this Project will improve the IPL transmission system operation and reliability. Customer operations and equipment, such as motors, can shut down because of voltage dips on the Bulk Electric System ("BES"). This can be a significant cost for large Commercial and Industrial ("C&I") customers. This Project will help reduce the likelihood of customer impacts from faults by removing faults from the system faster.

6.8.5 Summary

IPL's Static Wire Performance Improvement Project will reduce system disturbances providing better customer power quality and will improve the operational performance of IPL's transmission system.

6.9 Remote End – Breaker Relay/Upgrades

Table 6.9.1 – Remote End – Breaker Relay/Upgrades Project Overview

Project Attribute	Description
TDSIC Activity	This Project consists of replacing circuit breakers and/or electromechanical relays on the remote end of transmission lines opposite a circuit breaker identified for replacement by the Risk Model and included in the TDSIC Plan Substation Assets Replacement Project.
Project Costs[29]	$28.0 million -- capital expenditure.

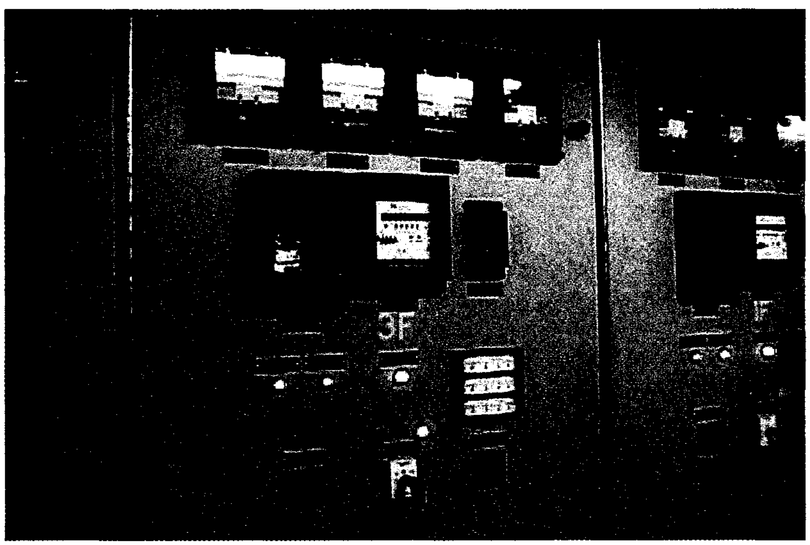
6.9.1 Background

The Remote End - Breaker Relay/Upgrades Project complements the breaker upgrades identified for replacement in the Risk Model and included in the TDSIC Plan Substation Assets Replacement Project. The Risk Model identified high risk transmission and sub-transmission (34.5 kV) line circuit breakers for replacement. The replacement of breakers includes the breaker equipment and, if needed, the protective relays associated with the breaker. Once these upgrades are completed the new breaker has enhanced capabilities above existing breakers that have not been upgraded. Representative pictures of the equipment targeted for replacement are set forth in Figures 6.3.1 and 6.3.2 below.

[29] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

Figure 6.9.1 – Oil Circuit Breaker Targeted for Replacement

Figure 6.9.2 – Electromechanical Relays Targeted for Replacement



To obtain the full benefits of the modernization associated with breaker replacements identified by the Risk Model, the breakers and relays at the remote ends of the transmission line needed to be investigated for deficiencies. IPL reviewed the list of breakers chosen by the Risk Model and evaluated the breakers and relays at the remote ends of those transmission lines. The review found that the breakers chosen for replacement, in some cases, left the remote end with equipment that would not allow the full capabilities of the modern equipment to be utilized. By upgrading both ends of the transmission line with modern breaker and relay technology, we can improve the functionality of the total line protection system.

By ensuring that the protection equipment on both ends of a transmission line are optimized for efficient, fast, and safe operations, IPL can improve the fault clearing capabilities of its transmission equipment. Faults that are cleared faster from transmission lines reduce equipment damage and increase the system reliability and performance seen by our customers. IPL looks at the protection of a transmission line as a system which includes all equipment at both ends of the line. It is IPL's standard practice to upgrade line protection equipment at both ends of a transmission line simultaneously.

6.9.2 TDSIC Purposes

This Remote End – Breaker Relay/Upgrades Project meets TDSIC purposes in several ways. Replacing older circuit breaker technology and electromechanical relays with newer circuit breaker technology and microprocessor relays helps modernize IPL's electricity delivery system and provides operational performance improvements. This enhanced operational performance results in more efficient operations with fewer maintenance cycles. The completion of this Project will improve the operation and reliability of the IPL transmission system.

6.9.3 Description of Physical Improvements

At each substation location listed below a circuit breaker, relay or both circuit breaker and relay will be upgraded.

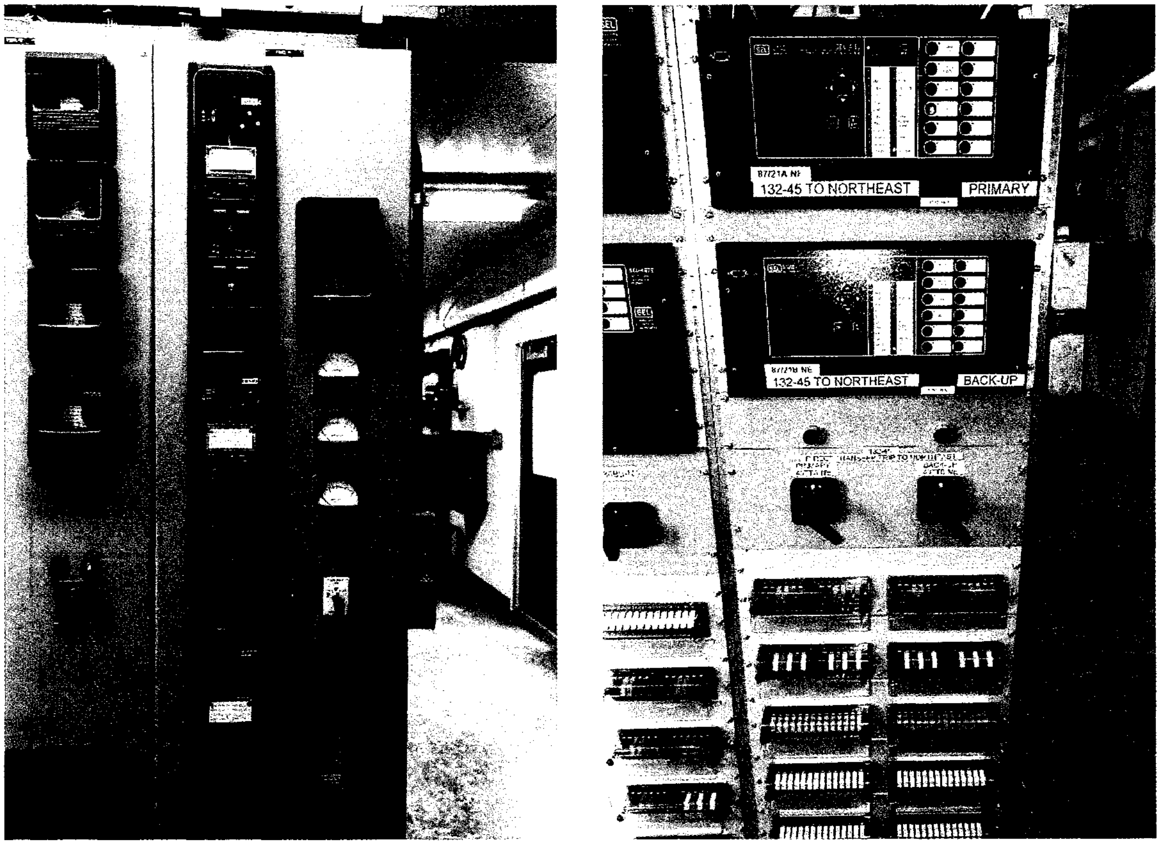
Table 6.9.2 – Locations and Types of Upgrades

Year	TDSIC Project	Type
2020	CASTLETON-132-54 BKR	Relay
2020	CASTLETON-132-55 BKR	Relay
2020	MILL STREET-132-65 LINE BKR.	Relay
2020	SUNNYSIDE-132-46 BKR	Relay
2020	SANITATION BLMT-138 BUSTIE OCB	Breaker
2020	ROCKVILLE-132-64 BKR	Breaker
2020	GLENS VALLEY-BUS TIE BKR	Breaker
2021	LILLY-SOUTH-132-61 BKR	Relay
2021	LILLY CORP-2451-1 BKR	Relay
2021	ENGLISH AVE-2471-1 BREAKER	Relay
2021	STOUT SOUTH YARD	Relay
2021	I.C.E.-BUS TIE BREAKER	Relay
2021	CRESTVIEW-138KV BUS TIE BKR	Breaker & Relay
2021	WEST-132-70W BKR	Relay
2021	WEST-132-63 BKR	Relay

2022	GLENS VALLEY-BUS TIE BKR	Relay
2022	IU CAMPUS N-3331-1 BKR	Relay
2022	LAWRENCE-132-48 BREAKER	Breaker
2022	STOUT N-132-14 WEST OCB	Breaker
2022	STOUT N-132-14 EAST OCB	Breaker & Relay
2022	MILL STREET-132-65 LINE BKR.	Breaker
2022	STOUT N-138-99 EAST OCB	Breaker & Relay
2022	STOUT N-138-99 WEST OCB	Breaker
2023	METHODIST HOSPITAL-3131-1 BKR	Relay
2023	ALLISON #3-451-1 BREAKER	Breaker
2023	SUNNYSIDE-132-46 BKR	Breaker
2024	NORTH-132-71-86 TIE BKR (7)	Relay
2024	CRESTVIEW-138KV BUS TIE BKR	Relay
2024	SANITATION BLMT-138 BUSTIE OCB	Relay
2024	CASTLETON-132-66 BKR	Relay
2024	LAWRENCE-132-45 BREAKER	Relay
2024	ST GT YD-132-02 BKR	Relay
2024	IU CAMPUS N-437-1 BKR	Relay
2024	PERRY K-34.5KV 2839-1 BKR	Relay
2024	IU CAMPUS W-391-1 BKR	Relay
2024	BROOKWOOD-1571-5 BKR	Breaker & Relay
2024	BROOKWOOD-132-36 BKR	Breaker
2024	NORTHWEST-132-04 BKR	Breaker & Relay
2024	NORTHWEST-132-39 BKR	Breaker & Relay
2025	CRAWFORDSVILLE RD.-132-35 BKR	Relay
2025	WILLIAMS ST-132-75 BREAKER	Relay
2025	LILLY CORP-4151-3 BKR	Relay
2025	NAVAL AVIONICS-1771-1	Breaker & Relay
2025	MAYWOOD-132-13 BREAKER	Breaker
2025	MAYWOOD-132-11 BREAKER	Breaker
2026	SOUTHEAST-132-72 BKR	Relay
2026	SOUTHEAST-132-18 BKR	Relay
2026	PROSPECT-1751-1 BREAKER	Breaker
2026	IU CAMPUS N-491-3 BKR	Relay
2026	IU CAMPUS W-431-3 BKR	Relay
2026	EAST-132-07 W BKR	Breaker
2026	WEST-132-70W BKR	Breaker
2026	WEST-132-06 BKR	Breaker & Relay

2026	WEST-132-63 BKR	Breaker
2026	EAST-132-07 E BKR	Breaker & Relay

Figure 6.9.3 – Before (left) and After (right) View of Circuit Breaker and Relay Upgrade



6.9.4 Benefits

The Remote End – Breaker Relay/Upgrades Project provides benefits for the IPL system Bulk Electric System in the following ways:

Improved Fault Clearing Times

The transmission line protective equipment forms a critical protective system. To optimize performance of the system, protection equipment on all ends of a transmission line need to have the same capabilities. With modern breaker and relay protection equipment, faults are removed from the electric system faster than with existing technology. This means that the damaging effects of fault currents flowing through the system are reduced, in turn extending the life of utility assets.

Further System Risk Reduction

While the primary goal of upgrading circuit breakers and relays is to improve the performance of the transmission protective system, when we replace additional equipment we are further reducing risk. By executing these projects in a coordinated manner at both ends of a transmission line simultaneously, IPL can efficiently upgrade each line section, while reducing the number of lines being taken out of service. This has value to our customers since all equipment outages pose a risk of degraded service.

Higher Fault Current Interrupting Capabilities

Additional DER on the IPL system increase available fault currents. Solar, wind, battery storage, and synchronous machines all contribute additional fault current. The breaker and relay upgrades help limit any issue IPL has with accommodating these new sources today and the expected increase in DER in the future.

Customer Benefits

The completion of this Project will improve the IPL transmission system operation and reliability. Customer operations and equipment, such as motors, can shut down because of voltage dips on the Bulk Electric System. This can be a significant cost for large C&I customers. This Project will help reduce the likelihood of customer impacts from faults by removing faults from the system faster.

Reduced Maintenance Cycles

The new modern substation equipment has longer durations between maintenance cycles relative to the existing equipment.

6.9.5 Summary

IPL's Remote End – Breaker Relay/Upgrades Project will reduce system disturbances providing better customer power quality and improving the operational performance of IPL's transmission system along with mitigating or avoiding maintenance cost increases.

6.10 Pole Replacements

Table 6.10.1 – Pole Replacements Project Overview

Project Attribute	Description
TDSIC Activity	IPL will replace approximately 330 wood poles annually based on inspection results of a ground line inspection and treatment program. This equates to 2,310 wood poles being replaced in the IPL TDSIC Plan.
Project Costs[30]	$24.2 million -- capital expenditure.

6.10.1 Background

Wood poles are essential infrastructure and a large asset base, by which electric utilities deliver energy to their customers. Utility best practices for maintaining wood poles include a ground line inspection and treatment program. IPL uses a ground line inspection and treatment program for its wood pole assets. IPL's entire wood pole fleet is inspected on a ten-year cycle. The inspections identify:

1.) ground line pole decay
2.) above ground pole decay
3.) pole top damage
4.) defects that may affect the integrity of the pole

Visual inspection of the pole at the ground line is critical because this is the most likely failure point. Freezing and thawing, the persistent presence of moisture and the ability for insect damage are the main reasons poles deteriorate at the ground line. During the inspection the pole is sounded with a hammer to detect decay. Based on the sound test the pole may be drilled to further evaluate the pole. In some cases, soil is removed to inspect the pole below grade to further inspect the pole for decay. Other common defects are poles splitting, wood pecker holes and unreported damage to the pole.

There are approximately 165,000 wood poles on the IPL system. IPL inspects approximately, 16,500 annually. IPL has a wood pole failure rate of 2.0%. Poles fail inspection in two categories. The first category is a "non-priority reject" inspection failure. These poles fail inspection criteria but do not need immediate attention. Non-Priority Reject poles are scheduled for replacement no later than the year following the failing inspection. The second category is a "Priority Reject" inspection failure. These poles fail inspection criteria with an elevated failure score. Priority poles

[30] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

are targeted for replacement within 30 days of failing inspection. Poles that pass the inspection are treated to prevent decay and further extend the life of the pole 10 years.

6.10.2 TDSIC Purposes

This Pole Replacements Project meets TDSIC purposes in two distinct ways. Replacing deteriorated poles improves public and employee safety in addition to maintaining system reliability.

6.10.3 Description of Physical Improvements

As discussed above, IPL has an inspection process whereby wood poles are inspected and tested above and below ground line and then replaced as necessary. Based on this inspection process, IPL will replace approximately 330 wood poles annually for a total of approximately 2,310 wood poles over the seven-year plan period. This inspection, recommended replacement, and number of replacements will be tracked for each year.[31] The IPL service territory is broken into 10 pole inspection areas.

6.10.4 Benefits

Benefits associated with the Pole Replacements Project are:

Safety

Replacing deteriorated poles improves public and employee safety. Failure of wood poles endangers the public by allowing energized conductors to fall below required clearances. Deteriorated poles also pose a danger to linemen who are required to climb poles to maintain and operate the electric system. Additionally, replacing deteriorated poles during emergency events generally involves adverse weather conditions, higher labor costs and the greatest number of customers without power. In contrast, replacing a deteriorated pole during normal work conditions can be accomplished more efficiently and cost-effectively and generally without taking customers out of service.

Harden the Electric System

Externally, a wood pole may appear to be in good condition but may have deteriorated internally and/or below the ground line to the point where the pole is no longer sufficiently strong enough to withstand horizontal loads produced by wind, or vertical loads caused by ice. Maintaining the integrity of the system's wood poles enables the electric system to better withstand the forces exerted on it by nature. Replacing poles under emergency conditions, such as during a storm event, can be significantly more expensive than during normal operating conditions.

[31] Technical specifications for inspection, groundline treatment and reinforcement of in-place poles, US Asset Management, Technical Specification #USSBU-10002-TD.

Add Resiliency to the Electric System

Maintaining the integrity of the wood poles reduces pole failure. This, in turn, better positions the electric system to bounce back from inclement weather events. Although the presence of failed poles may not necessarily impact the number of customers who lose power during a storm event, failed poles have a large impact on the duration and the cost of the restoration effort.

Risk Reduction

A systematic pole inspection and replacement project whereby deteriorated wood poles are removed and replaced reduces the overall risk of operating and maintaining the electric system.

6.10.5 Summary

The Pole Replacements Project is an accepted industry best practice that will maintain the integrity of the electric system along with safeguarding overall public and employee safety.

6.11 Steel Tower Life Extension

Table 6.11.1 – Steel Tower Life Extension Project Overview

Project Attribute	Description
TDSIC Activity	IPL will excavate and apply an anticorrosion protective coating to approximately 670 direct-buried steel transmission structures over a four-year period beginning in 2020. Many of these existing structures are rapidly approaching the end of their design lives and represent a potentially serious risk if left untreated. The life-extending coating proposed to be applied is a technological advancement in protective coating technology designed to extend the towers' useful life by up to 20 years.
Project Costs[32]	$4.2 million – capital expenditure

6.11.1 Background

IPL has approximately 3,500 steel transmission structures (both poles and lattice towers) carrying various circuits of its 866 miles of 138,000 and 345,000 Volt (138 kV and 345 kV respectively) electric transmission lines. Most of these structures are supported upon reinforced concrete foundations. However, approximately 670 structures are supported upon bare, galvanized steel buried directly in the earth. Most of these 670 structures were installed in 1932 (365 - 138 kV towers) and in the 1950's (204 - 138 kV towers). This Project supports ongoing safety and reliability as these structures age.

There are essentially two courses to address the direct-buried steel transmission structures -- replace the assets or utilize modern technology to extend their lives. There is an increasing risk of structure failure due to corrosion of the direct-buried steel. Corrosion is the result of an electrochemical reaction of a metal within its environment whereby the metal reverts to its original base elements. To date, corrosion of the direct-buried steel has been maintained by protective galvanized coating, but this coating has reached its end of life and needs refurbished.

Replacing the assets is costly and unnecessary. Instead, IPL will utilize modern steel coating technology to extend the life of these assets by approximately 20 years for an estimated cost of $4.2 million. Ideally, this Project may be repeated in 20 years for another 20-year life extension assuming all other aspects of the structures remain viable.

[32] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

6.11.2 TDSIC Purposes

This Steel Tower Life Extension Project meets TDSIC purposes in two key ways. First, the Project proactively addresses potential public safety concerns. When the 1932 vintage structures were initially installed, they were located primarily in very rural areas inside of Marion County. After years of development, things are considerably different today; these structures are located in now tightly-congested, urban environments. Proactively addressing potential structure failures safeguards the public and employees.

Second, the Project will proactively improve the IPL transmission system operation and reliability. While not currently experiencing unplanned outages due to structure failures, without this Project the likelihood of structures failing increases

The Project will provide valuable information on the condition of IPL's direct-buried steel assets that will enable IPL to better manage and control future capital and operational costs. A planned, proactive approach is a much more efficient maintenance approach than reactive emergency repairs.

6.11.3 Description of Physical Improvements

IPL will excavate around each leg of identified, direct-buried steel structures to a depth of up to 24 inches, clean the steel, apply a technically-advanced protective polymer coating, refill the hole with the previously-excavated soil, and restore any property damaged during the process.

Figure 6.11.1 – Before/After Photos of a Typical Direct-Buried Steel Tower Leg

Due to the properties of the proposed coating, this work can only be performed under moderately warm conditions. IPL proposes to treat every direct-buried steel structure starting in Spring 2020 and continuing for four seasons, ending in the Fall of 2023.

Table 6.11.2 – Schedule

YEAR	ACTION
2020	183 Structures Treated
2021	182 Structures Treated
2022	170 Structures Treated
2023	133 Structures Treated
Total	668 Structures Treated

6.11.4 Benefits

IPL's Steel Tower Life Extension Project benefits the IPL system and IPL's customers, including the following:

- IPL will extend the life of assets at a nominal cost compared to asset replacement.
- IPL will mitigate the risk of failure of transmission structures due to below-grade corrosion.
- This Project will mitigate public and employee safety risk.
- IPL will mitigate the risk of unplanned transmission outages due to structure failures.
- IPL will mitigate the risk of unplanned or emergency maintenance.
- IPL will be able to better manage and control capital and O&M costs through valuable data that can be used for more robust asset management.
- By mitigating risk of structure failure and outage, this Project will improve system reliability and mitigate risk and duration of customer outages.

6.11.5 Summary

In summary, the Steel Tower Life Extension Project prudently addresses important infrastructure which may reasonably be expected to experience increasing reliability and operational issues if left to deteriorate. This Steel Tower Life Extension Project provides system and customer benefits such as reduced safety and structure risk.

6.12 Distribution Automation

Table 6.12.1 – Distribution Automation Project Overview

Project Attribute	Description
TDSIC Activity	IPL will install 1,200 new distribution line reclosers and a new central control system to increase system automation; to improve distribution system operation and reliability; to enable voltage management and associated energy conservation; and to facilitate interconnection with distributed energy resources and new loads.
Project Costs[33]	$109.0 million - capital expenditure

6.12.1 Background

IPL currently uses three control systems to help manage distribution operations. The three control systems are the Radio-Controlled Capacitor System (RCCS), the Distribution Supervisory Control & Data Acquisition (DSCADA) and the Outage Management System (OMS). RCCS is a basic power factor control system that maintains power factor at the substation level. DSCADA gathers status data and controls devices. OMS helps manage customer outages. These systems lack integration and all three systems are nearing obsolescence.

As of December 31, 2018, IPL has installed nearly 300 reclosers on distribution poles to improve reliability by isolating trouble on distribution lines to smaller sections. The use of reclosers increases circuit sectionalization, and this reduces the number of customers who experience an outage when a fault occurs. This technology also gives system operators opportunities to remotely control service restoration. IPL's experience with the existing reclosers along with analysis of modern control system capabilities indicate the IPL distribution system and IPL's customers will benefit from 1200 additional reclosers and modern central controls.

Technological limitations in the existing control systems and lack of real time data causes uncertainty about the actual voltage delivered to customers. As a result, IPL (and the industry generally) has traditionally kept substation voltages on the higher end of the allowable range. This practice assures customers located at the end of the distribution lines have adequate voltage. IPL (and the utility industry generally) knows that lower voltages within allowable ranges help customer equipment use less energy. IPL's existing capacitor control system, RCCS, is not designed to deliver integrated Volt/var control (and associated energy savings) to customers.

[33] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

IPL's experience with temporary demand reduction together with industry knowledge confirm that a modern control system can deliver energy savings and distribution system benefits. These benefits will be enabled by voltage sensors associated with the proposed reclosers and the modern distribution control system discussed above. This modernized infrastructure is estimated to reduce customer energy consumption by 1%, saving (about 112,000 MWh per year).

Finally, the electric distribution system is transforming from a traditional radial power flow to a bi-directional power flow grid. More specifically, electric vehicles, solar, wind and battery storage systems connected to the grid are changing how IPL operates and maintains the system.

IPL has significant experience integrating large solar projects into the distribution system. IPL's experience confirms that distributed resources can introduce safety, reliability and power quality concerns on the distribution system. The complexity of these concerns grows with each new site and as more localized distributed resources are added to the system. The proposed modernization of IPL's distribution control system is necessary to facilitate the ongoing interconnection with these types of resources.

6.12.2 TDSIC Purposes

The Distribution Automation Project adds distribution infrastructure and replaces older control systems with modern control systems that will increase automation, improve distribution infrastructure safety, operation and reliability, facilitate outage management and service restoration; enable voltage control and associated energy conservation; and improve interconnection with distributed resources.

Reliability improvements are achieved by strategically placing 1,200 new reclosers on distribution circuits. These reclosers can better detect, locate and isolate problems on the distribution system. Repair crews can be more accurately directed to the source of trouble. Improved location detection and associated faster crew arrival times enhance public and employee safety. A modern control system improves reliability with Fault Location, Isolation, and Service Restoration (FLISR) functionality. The FLISR functionality is estimated to eliminate, on average, 23,000 customer interruptions per year. It is also expected to reduce the duration of approximately 167,000 interruptions per year to less than 5 minutes. The Department of Energy Interruption Cost Estimate ("DOE ICE"), a widely accepted benefits calculator, indicates IPL customers will realize about $21 million of value per year when the project is completed.

Modernizing the control system and leveraging the existing capacitor controls will enable voltage management and associated energy conservation. The voltage sensors associated with the proposed reclosers eliminates the need for independent sensors on the system. The Distribution Automation Project is estimated to will reduce customer energy consumption by 1%, saving about 112,000 MWh per year.

The new central control system replaces three different infrastructures with a single integrated system. All three of the legacy systems have different operator interfaces and different interfaces to essential circuit models. The new system streamlines the interface to models and gives system operators much better situational awareness with integrated displays.

The Distribution Automation Project is undertaken for purposes of safety, reliability and system modernization while providing benefits to IPL customers and facilitating economic development.

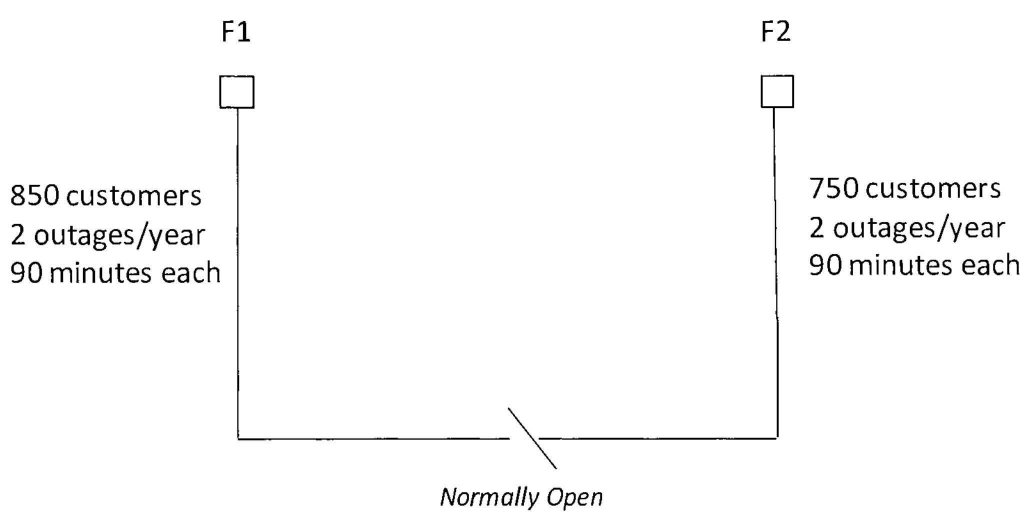
6.12.3 Description of Physical Improvements

IPL will procure, program and install 1,200-line reclosers on distribution poles located throughout the IPL service territory. The reclosers will be deployed equally over the seven-year TDSIC Plan period. The reclosers will be strategically positioned to create sections with about 400 customers in each section. These reclosers will have two-way remote communication. They will have autonomous and remote-control capability. The reclosers will also have accurate voltage and current sensors on each of the three phases to facilitate Volt/var control described below.

Fault Location, Isolation, and Service Restoration (FLISR)

Figures 6.12.1 and 6.12.2 below show a simple, hypothetical example to illustrate customer outage experience before and after installing reclosers with Distribution Automation FLISR. The initiating events in Figures 6.12.1 and 6.12.2 are identical but the customer experience materially improves with FLISR.

Figure 6.12.1 - Customer experience before Distribution Automation



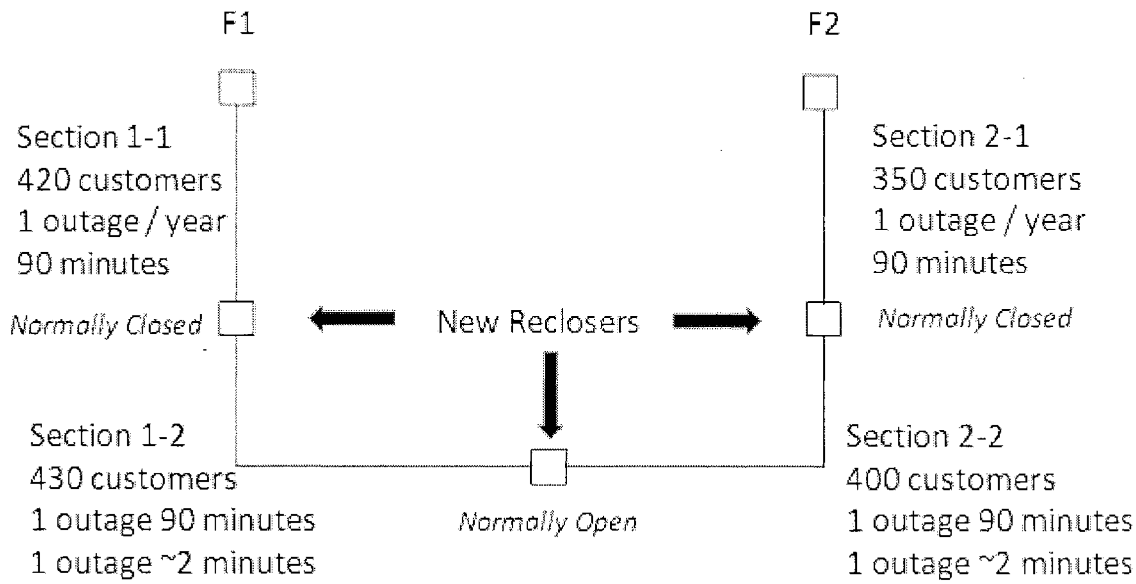
Trouble Anywhere on F1 Section

The 850 customers served from Feeder 1 (F1) will experience a total of 2 ninety-minute outages

Trouble Anywhere on F2 Section

The 750 customers served from Feeder 2 (F2) will experience a total of 2 ninety-minute outages

Figure 6.12.2 - Customer experience after Distribution Automation



Trouble on Sections 1-2 or 2-2

Figure 6.12.2 shows the improvement after reclosers are installed. Customers on Sections 1-1 and 2-1 see one less outage per year because the normally closed reclosers open automatically for any trouble on Sections 1-2 or 2-2. Customers on Sections 1-2 and 2-2 will still experience a sustained outage for trouble in their section. However, repair crews have much better information about the trouble location which helps shorten repair times.

Trouble on Sections 1-1 or 2-1

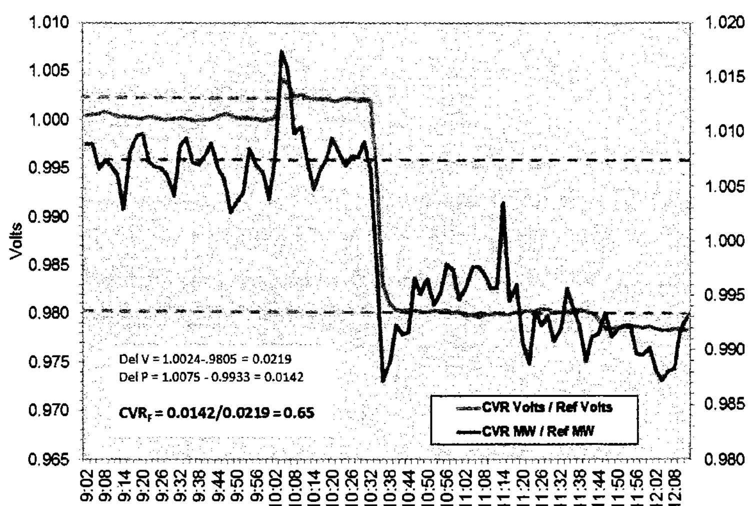
Customers on Sections 1-2 and 2-2 also experience outages for trouble on Sections 1-1 and 2-1 before distribution automation. However, when Distribution Automation performs FLISR, service is automatically restored by alternate supply. After FLISR is deployed customers in sections 1-1 and 2-1 still experience sustained outages while customers in section 1-2 and 2-2 only experience a brief outage for trouble on sections 1-1 or 2-1.

Integrated Volt/var Control (IVVC)

The new central distribution control system will include modern IVVC capability. This will replace the outdated capacitor control system. IVVC will optimize distribution voltages to achieve energy savings for IPL customers. IVVC can provide additional visibility and operational flexibility in responding to system conditions. The IVVC Project will use load and voltage data from the new and existing reclosers, substation equipment and existing capacitors. It will take that data, perform optimization calculations and send control signals to capacitors and substation voltage regulation equipment.

Figure 6.12.3 shows results of a test IPL performed to accurately measure load response to voltage. The test treated about half of the load with a voltage reduction. The other half was left untreated for a baseline. Figure 6.12.3 shows how the treated voltage was lowered 0.0219 per unit (2.19%) compared to the reference baseline. The treated load dropped 0.0142 (1.42%) compared to the reference baseline. This calculates a Conservation Voltage Reduction (CVR) factor equal to 0.65. In general, a 1% voltage reduction will yield 0.65% reduction in energy consumption.

Figure 6.12.3 – Test for conservation voltage reduction



Once the Distribution Automation control system is operational, IPL will lower the average system voltage by 2% on the 13.2 kV distribution feeders. CVR will be applied to all distribution circuits from 90 distribution substation transformers. This represents a historical peak load of 2,000 MW which is roughly 75% of IPL's system peak demand. (CVR is not practical for IPL's transmission and sub-transmission systems.) IPL will make a conservative assumption of CVR factor equal to 0.5 for future loads. This yields a conservative 1% energy savings over the life of the project.

IPL will replace a rudimentary distribution DSCADA with the new central computer control system. This will provide operators with much greater situational awareness and flexibility for complex operations.

IPL will also incorporate a legacy OMS as part of the new master distribution control system. The existing OMS has been adequate but there are no indications that it will be upgraded to include FLISR or IVVC necessary to achieve the needed reliability and conservation benefits.

6.12.4 Benefits

IPL's Distribution Automation Project offers a variety of benefits to the distribution system and IPL customers. The Project improves reliability, enhances safety and provides voltage management and associated energy conservation. Additionally, modern infrastructure facilitates economic development. The Distribution Automation Project also prepares the distribution system for the ongoing development of distributed energy resources and loads. Project benefits are further described below:

Safety

The Distribution Automation Project enhances safety in many ways. Repair crews have more accurate information about the location of trouble. This helps them arrive earlier and make areas safe sooner. Critical infrastructure such as fire stations, traffic lights, sewage lift, health care, and life support see fewer outages and remaining outages are often have a much shorter duration.

Customer Reliability Improvement

The reclosers and Distribution Automation will perform FLISR. This system will eliminate about 23,000 customer interruptions per year and substantially shorten the duration of about 167,000 interruptions.

Customer Energy Savings

Distribution Automation will use the new reclosers along with the new control system and other existing equipment to perform IVVC. The conservative estimated CVR factor described earlier will reduce average energy consumption by 1% per year. This reduces energy consumption and by at least 112,000 MWh per year.

Distributed Resources and New Loads

New distributed resources and loads place additional challenges to the distribution system. IPL has considerable experience with distributed resources as a result of IPL's Renewable Energy Production tariff, which made Indianapolis a leader in solar development. These distributed resources have occasionally caused excess voltage, improper fault isolation, higher short circuit currents, and possible back feed. Residential loads attempting solar net zero energy create reverse peak demands two to three times the original forward demand. This reverse demand could overload supply equipment. The Distribution Automation Project will help make these issues and other issues visible to IPL operations and provide more capability to deal with them.

Improved Distribution Control Capabilities

The Distribution Automation Project overcomes obsolescence concerns of three disparate control systems in service today. The existing distribution DSCADA does not provide adequate operational awareness. The RCCS does not and will not perform IVVC for the necessary energy savings. The outage management system is unlikely to ever incorporate DSCADA, IVVC, and FLISR into a single package. The Distribution Automation Project brings all these functions together. It substantially reduces the cost of building software interfaces between disparate systems. It substantially improves operational awareness and efficiency of the distribution system.

6.12.5 Summary

IPL's Distribution Automation Project increases circuit sectionalization and provides a modern control system to automate and modernize the distribution system while also providing benefits, such as voltage management that are not available through IPL's existing control systems and facilitating interconnection with distributed resources. The Distribution Automation Project enhances safety and reliability. The better reliability and acceptance of new loads enhances future economic development.

6.13 Substation Design Upgrades

Table 6.13.1 –Substation Design Upgrades Project Overview

Project Attribute	Description
TDSIC Activity	IPL will reconfigure and/or add capacity at six existing substations and construct two new substations for additional distribution system capacity. These substation projects will improve load serving capability, operability, and reliability of the electric system.
Project Costs[34]	$94.5 million -- capital expenditure

6.13.1 Background

IPL owns and maintains a large fleet of transmission and distribution substations located throughout its service territory. The substations are essential infrastructure for the safe and reliable delivery of electricity to IPL's customers. In the context of this project, improving deliverability of the IPL electric system has two components. First, reconfiguring or adding system elements enables the electric system to isolate faults (contingent events) without removing as many elements from service. This improves reliability to the electric system. Second, adding capacity, through larger current carrying equipment, enables the electric system to absorb the loss of system elements. This too improves the reliability of the electric system.

As part of the overall TDSIC initiative, IPL has focused attention broadly on the imperative of replacing high risk assets. The role of new functionality, such as Distribution Automation, focuses on ensuring that the IPL electric system is positioned to adequately serve load. The substation projects improve IPL's ability to deliver energy to customers in the following ways:

- Improve load serving capacity to support customer load growth.
- Lower the risk of customer outages during transmission and/or substation maintenance by improving the operability and maintainability of the system.
- Enhance transmission system performance, with respect to North American Electric Reliability Corporation (NERC) requirements, by creating a more reliable substation design to address contingencies.
- Reduce congestion caused by the need for system redispatch on the BES.

[34] See Section 4.4 of TDSIC Plan for discussion of cost estimate development. See Appendix 8.7 for cost estimates and year by year project detail.

Table 6.13.2 provides a summary of these objectives mapped to each of the substation projects, noting benefits.

Table 6.13.2 –Substation Design Upgrades Objectives

Project (Substation)	Improve Load Serving Capability	Improve Operability related to NERC Performance Requirements	Bring Substation to Current Design Standards	Reduce Outage Risks and Improve Operational Flexibility
Mooresville	X		X	X
Guion		X		
Rockville		X		
Stout		X		
Center			X	X
Prospect			X	X
New- Sub 2023	X			
New- Sub 2025	X			
Drop-In Control Houses				X

6.13.2 TDSIC Purposes

The Substation Design Upgrades Project meets TDSIC purposes in following ways:

- By modifying substation configurations, through ring bus configuration and other means, IPL will improve the operability and reliability of the IPL transmission and distribution system.
- Certain substation modifications improve operability and reliability by removing operating guides otherwise required to meet NERC transmission system planning performance requirements. These projects improve the BES by increasing system import limits and operational flexibility, lowering congestion caused by the need for system redispatch, and addressing risks posed by contingency events.
- Modifying the topology of substations allows IPL to reduce exposure to outages while performing maintenance on the system. Reduced exposure is accomplished by taking smaller sections of the system out of service to perform routine maintenance on equipment. These improvements will modernize the IPL system and increase its overall reliability.

- The Substation Design Upgrades project will add distribution capacity to the system that can be used to support economic development initiatives in the Indianapolis metropolitan area.

6.13.3 Description of Physical Improvements

Below are descriptions of the Substation Design Upgrades projects:

1.) **Mooresville Substation** -- IPL will replace two power transformers increasing the capacity of the distribution system. IPL will also install two new 138 kV breakers and reconfigure the 138-kV bus to form a ring bus. The project also includes modern relay packages and associated equipment.

2.) **Guion Substation** -- The Guion Substation project removes the risk of potential overloads under certain contingency events. Thermal ratings of equipment are exceeded for certain outage contingencies and IPL relies upon operating guides to reconfigure the system to meet the transmission system planning performance requirements of TPL-001-4. To address this, IPL will add a 345/138 kV transformer and modify the existing substation configuration to include a 345 kV ring bus. This requires three new 345 kV breakers and two new 138 kV breakers.[35]

3.) **Rockville Substation** -- The Rockville Substation project removes the risk of potential overloads under certain contingency events. Thermal ratings of equipment are exceeded for certain outage contingencies and IPL relies upon operating guides to reconfigure the system to meet the transmission system planning performance requirements of TPL-001-4. To mitigate this, IPL will install a new 345 kV breaker at the Rockville Substation to create a ring bus configuration.

4.) **Stout Substation** -- The Stout Substation project removes the risk of potential overloads under certain contingency events. Thermal ratings of equipment are exceeded for certain outage contingencies and IPL relies upon operating guides to reconfigure the system to meet the transmission system planning performance requirements of TPL-001-4. To mitigate this, IPL will install a new 345 kV breaker at the Stout Substation to create a ring bus configuration.

5.) **Center Substation** -- The Center Substation project updates the substation to modern construction and design standards, which will improve worker safety and IPL's operational flexibility. IPL will add a total of three new 138 kV breakers and replace three existing 138 kV breakers. One of the new breakers will be a line breaker and the other two will be transformer breakers. These breakers provide the ability to isolate faults

[35] For the thermal exceedances described in the Guion, Rockville, and Stout substation projects, IPL is in full compliance with NERC TPL-001-4 requirements. The improvements described here offer a superior means of transmission system performance and confer other benefits to both the BES and IPL customers.

(contingent events) without removing as many elements from service. This equipment allows IPL to reconfigure the bus arrangement in the substation. IPL will also replace an existing 34.5 kV capacitor with an enclosed capacitor that includes a pre-insertion resistor.

6.) **Prospect Substation** -- The Prospect Substation project increases IPL's system reliability and operational flexibility. IPL will add one new 138 kV line breaker. The principal goal of this modification is to provide isolation of two transformers from the 138-kV line. The current station arrangement includes common bus among both transformers and the transmission line, which requires distribution circuit outages to isolate the line for faults. The addition of the breaker allows for separate isolation and directly increases customer reliability.

7.) **New Substation 2023** – The Substation Design Upgrades Project includes a new 138/13.2 kV substation in 2023. The new substation is needed to convert the 4 kV system load to the 13.2 kV system. The project will include three 138 kV breakers, two 138/13.2 kV 40 MVA transformers, and all necessary associated switches and relay/protection equipment.

8.) **New Substation 2025** – The Substation Design Upgrades Project includes a new 138/13.2 kV substation in the IPL service area near the old southside. This area, which once served an industrial load, is now being revitalized and IPL needs facilities to serve the mixed-use load from the ongoing economic development of this area. This new substation is planned to be placed in service to meet service needs in 2025. The new distribution substation will also provide additional operational flexibility to serve load from other nearby substations. The project will include three 138 kV breakers, two 138/13.2 kV 40 MVA transformers, and all necessary associated switches and relay/protection equipment.

9.) **Drop-In Control Houses -** At substations where significant upgrades will take place, utilizing a drop-in control house reduces cost and adds efficiency and operational security to a substation upgrade project. A drop-in control house provides the ability for all protection and control equipment to be installed and tested at one time without complicated equipment outages. When yard equipment is replaced, cables are installed between the yard equipment and the new control house. This allows for the equipment to be returned to service faster with less risk of a human error or the need for extensive work in and around energized relay panels. Drop-in control houses will be utilized for three substation projects in IPL TDSIC Plan, Southwest Sub, Northwest Sub and Northeast Sub.

6.13.4 Benefits

There are several tangible benefits associated with the Substation Design Upgrades Project.

Improved Transmission Performance with Respect to NERC Compliance

Several substation improvements improve IPL's transmission system performance. This means that IPL operators will be able to more efficiently operate the transmission system for contingency events. The resulting conditions improve total system reliability and reduces risks. These changes, in turn, improve the BES operational flexibility and reliability, and decrease the dispatch of generators under certain conditions (reducing fuel and other operating costs). In some circumstances system import limits are improved. These changes also lead to reduced congestion, thereby lowering IPL's local zone locational marginal pricing (LMP) to which system participants are exposed.

Improve Distribution System Capacity & Capability

Several deliverability projects will improve IPL's distribution system capacity and capability. IPL will create permanently engineered solutions to serve load needs either through system expansion or substation rehabilitation. These capability improvements include increased load serving capacity and resiliency, economic development benefits throughout the IPL system, and superior mobile equipment implementation strategies. The substation improvements also give IPL the means to perform maintenance without forcing re-dispatch of the system, which mitigates congestion. Therefore, by creating greater operating flexibility, the overall system reliability is improved.

Improved Maintainability and Reduced Customer Outage Risks

By modifying the topology of the substations, IPL increases its operating flexibility. This improves IPL's ability to maintain the substations without creating outage risks for customers. This improves the IPL system reliability and reduces total system risk. Some of these benefits also accrue when bringing older substations up to current designs.

Enables Continued Economic Development

The Substation Design Upgrades Project positions the IPL electric system to enable the continued economic development the City of Indianapolis is experiencing. As the City of Indianapolis attracts new business and industry the Substation Design Upgrades Project will absorb the electric load that comes with them. These projects will allow IPL to continue to provide reliable and efficient delivery of energy to our existing and future customers.

6.13.5 Summary

The Substation Design Upgrades Project is a strong example of how reasonable, prudent engineering planning and design applied to changing system conditions can lead to many benefits, which ultimately accrue benefit to IPL's customers.

Moreover, these benefits are well aligned to TDSIC purposes and will result in a better delivery system for IPL and its customers, one that is safer, more reliable, and more resilient in the face of many potential system contingency events.

7 Plan Implementation

7.1 Implementing IPL's TDSIC Plan

The implementation of IPL's TDSIC Plan will be will be managed by a Project Management Organization (PMO). The PMO is responsible for each TDSIC Project's scope, cost and schedule. The PMO is charged with bringing accountability, visibility and repeatability to TDSIC project execution.

Accountability is accomplished by having the PMO own the implementation of the IPL TDSIC Plan. The PMO will work with internal and external partners to manage each Project using project management principles and tools. The PMO works in collaboration with Operations, Safety, Engineering, Environmental, Supply Chain, Accounting, Accounts Payable, Regulatory and other functional areas to create and execute Project plans. Project Managers will be responsible for Project plans and each Project life cycle step: initiate, plan, execute, monitor/control and close out.

Visibility into project health of the TDSIC Plan can be achieved by a variety of industry standard tools which provide a snapshot in time on the progress of individual projects. The PMO will compare the planned implementation schedules to the actual progress of projects to identify variances of cost, schedule and scope. These variances are tracked and acted upon to drive the actual cost, scope and schedule to the plan.

Repeatability will be accomplished through a PMO sponsored lesson's learned process. At the completion of a project the project team evaluates the variances to the plan and determines what corrective actions can be taken to mitigate future similar project variances. These lessons learned are then socialized with the broader project management team so that visibility into future projects can be obtained.

8 Appendices

8.1 Map of IPL Service Territory

8.2 Map of Indianapolis Central Business District

8.3 Burns & McDonnell Risk Model Report

8.4 Black & Veatch Review of the Burns & McDonnell Risk Model

8.5 IBRC's Economic Impact Assessment Report

8.6 Black & Veatch Cost Estimate Review and Validation Report

8.7 Cost Estimates, Year by Year Project Detail (Sortable List) and Plan Projects by FERC Account

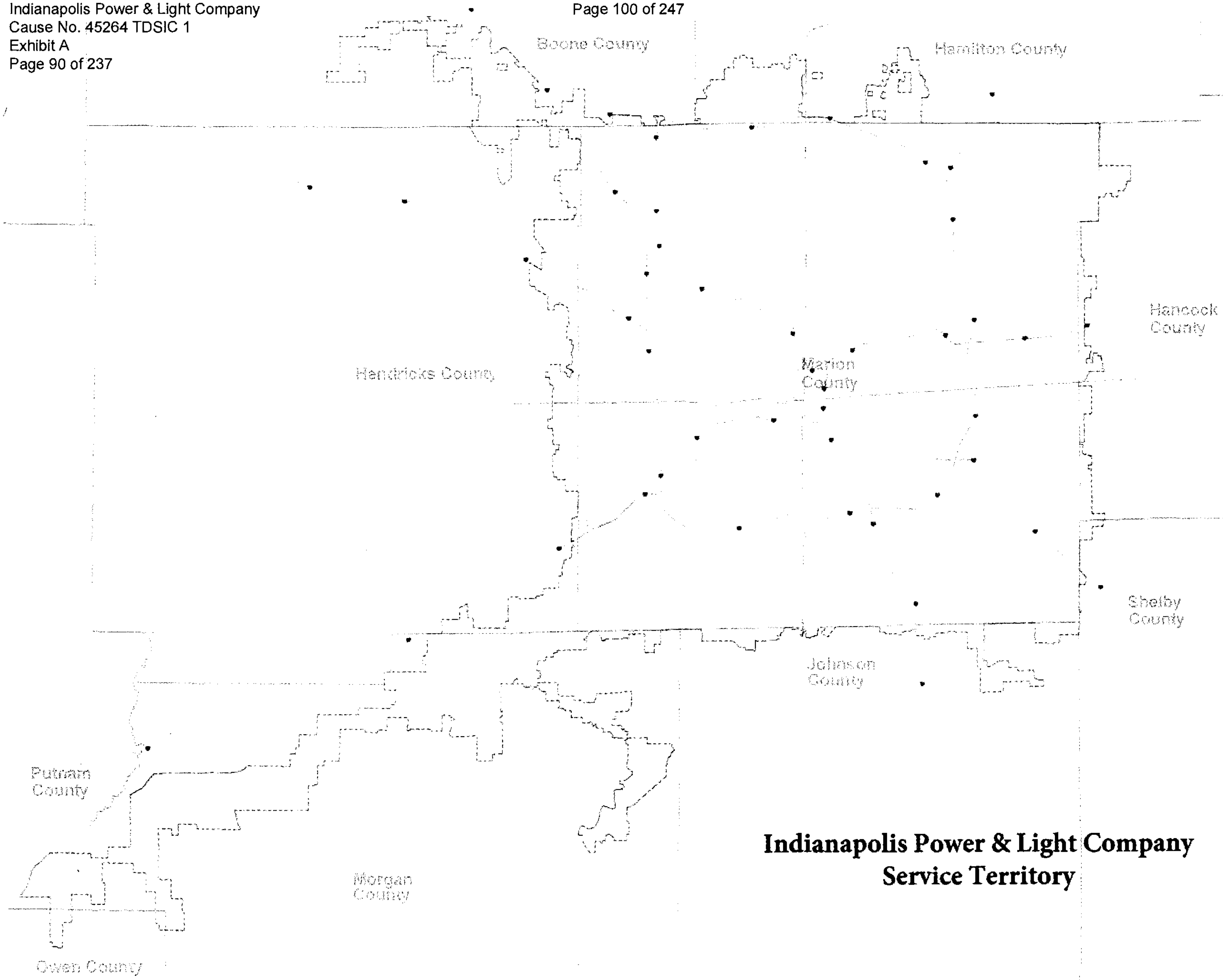
8.8 Class 2 Estimate Example

8.9 Class 3 Estimate Example

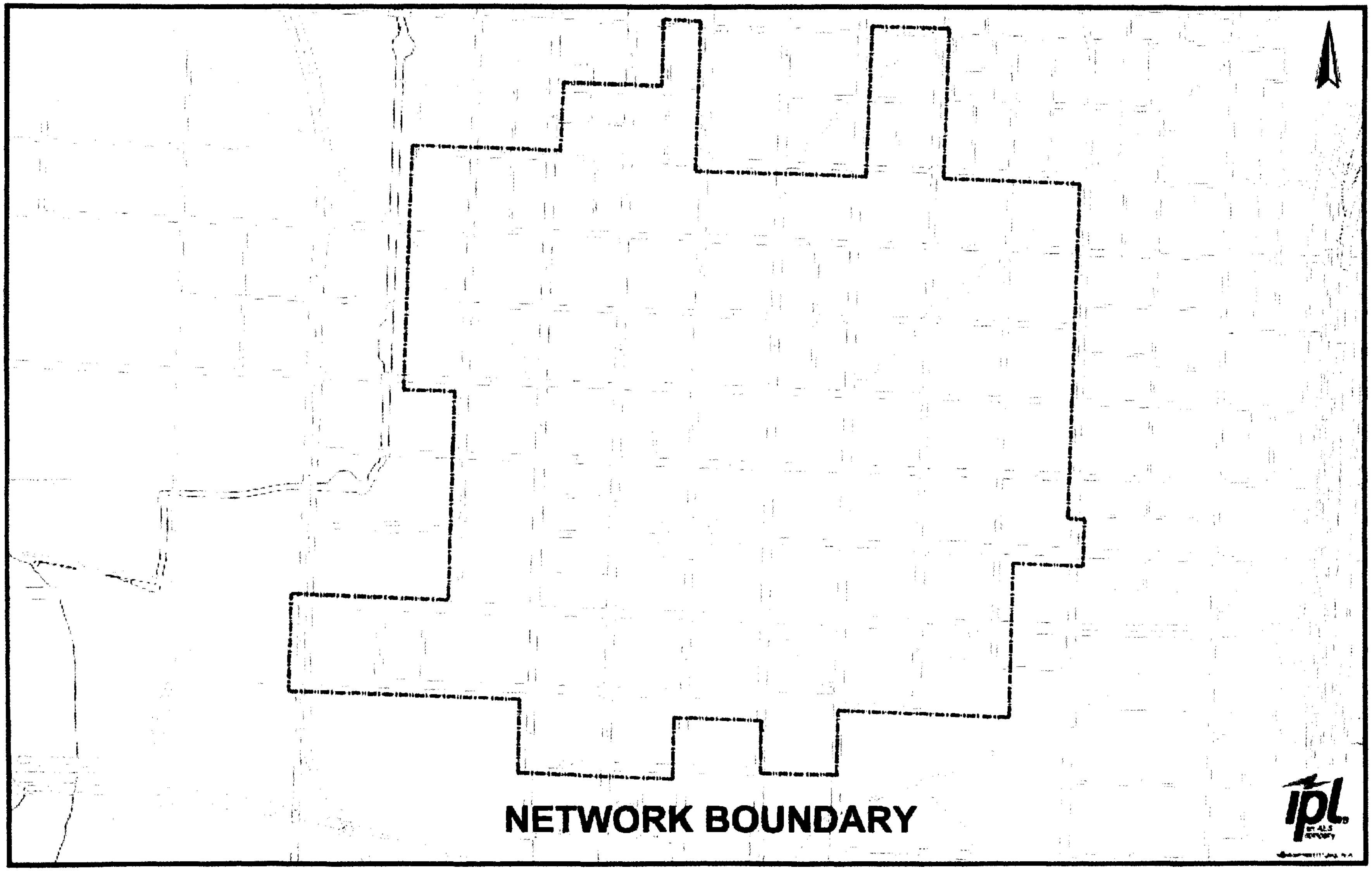
8.10 Class 4 Estimate Example

8.11 Risk Reduction Benefit Monetization Report

Appendix 8.1 Map of IPL Service Territory


Boone County
Hamilton County
Hancock County
Hendricks County
Marion County
Shelby County
Johnson County
Putnam County
Morgan County
Owen County
Indianapolis Power & Light Company
Service Territory

Appendix 8.2 Map of Indianapolis Central Business District


NETWORK BOUNDARY

Appendix 8.3 Burns & McDonnell Risk Model Report

Asset Risk & Investment Assessment Report

Indianapolis Power & Light Company

IPL TDSIC Asset Risk & Investment Assessment Report
Project No. 104713

Asset Risk & Investment Assessment Report

prepared for

Indianapolis Power & Light Company
IPL TDSIC Asset Risk & Investment Assessment Report
Indianapolis, Indiana

Project No. 104713

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
AHI	Asset Health Index
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
COF	Consequence of Failure
DGA	Dissolved Gas Analysis
GIS	Geospatial Information System
IPL	Indianapolis Power & Light Company
ISO	International Standards Organization
LOF	Likelihood of Failure
OH	Overhead
T&D	Transmission and Distribution
TDSIC	Transmission, Distribution and Storage System Improvement Charge

1.0 EXECUTIVE SUMMARY

IPL engaged the services of Burns & McDonnell in developing the TDSIC asset risk assessment and investment analysis. In collaboration, IPL and Burns & McDonnell utilized a risk-based planning approach to identify assets for replacement and prioritize investment in the T&D system. While risk-based planning approaches have many purposes, two key purposes for the Asset Risk Model are:

1. Identify high-risk assets and establish a plan to manage the risk.
2. Identify the highest risk reduction per dollar invested for the system.

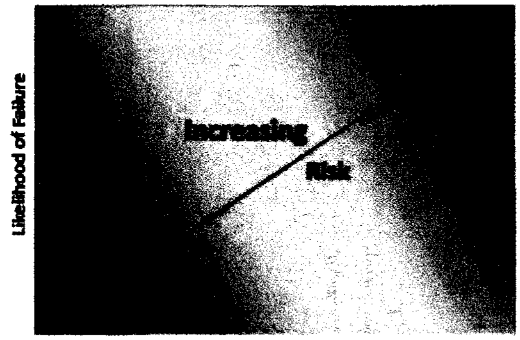
While risk reduction is a significant benefit and the focus of this report, it is not the only benefit of IPL's TDSIC Plan. Additional benefits are described and quantified elsewhere in IPL's TDSIC Plan[1]. The Asset Risk Model follows best practice and includes the required elements to identify and prioritize assets for replacement. Risk-based prioritization facilitates the identification of the critical assets most likely to fail. Prioritizing and optimizing investments in the system helps ensure the ratepayers get the "biggest bang for the buck."

The Asset Risk Model utilizes survivor curves to calculate an assets likelihood of failure. When available, asset condition and health information is used to calculate an asset's 'effective' age. Asset health indices incorporating IPL's recent condition assessment information were calculated for power transformers, breakers, and wood poles, which comprise a significant portion of the asset base in the Asset Risk Model. Additionally, the Asset Risk Model incorporates asset criticality to calculate a consequence of failure score across a range of established criteria. The Asset Risk Model leverages much of the asset management approach reviewed with IPL stakeholders during a recent asset management collaborative effort.2 Using the elements described above, IPL and Burns & McDonnell evaluated three investment scenarios within the Asset Risk Model to inform the development of IPL's TDSIC Plan.

[1] See IPL TDSIC Plan Section 3 for discussion of Plan benefits.
[2] This collaborative was conducted per IURC Order in Cause No. 44576 dated March 16, 2016.

1.1 Risk Based Planning Approach

Figure 1-1: Risk Matrix



In alignment with best practice asset management and the International Standards Organization (ISO) definition of risk (ISO 31000), the Asset Risk Model defines risk for an asset as being the product of the likelihood of failure (LOF) and the consequence of failure (COF) or impact caused by the failure. Typically, risk results are visualized using a risk grid/matrix, or heat map. The upper right-hand corner zone demands special consideration and attention. An example risk grid is shown in Figure 1-1. Use of this methodology enables a better understanding of which assets pose the highest risk to the electric system and this in turn assists IPL in optimizing the portfolio of aging asset replacement.

Similarly, the Asset Risk Model adheres to best practice and ISO standards for risk management. The basic framework for the risk assessment follows the process below:

- Risk identification – the asset register, asset definition, and expected asset failure mode
- Risk assessment – consequence and likelihood frameworks including asset health
- Risk mitigation measure development – asset replacements and project bundling
- Risk mitigation measure implementation – executing the mitigation plan

The Asset Risk Model uses the process and approach outlined above for assessing risk. The adjacent table, Table 1-1, shows the LOF and COF risk grid framework utilized in the Asset Risk Model.

Table 1-1: Risk Framework

Score	LOF	COF
1	Remote	Very Low
2	Low	Low
3	Moderate	Moderate
4	High	High
5	Very High	Very High

1.2 Asset Risk Model Overview

The risk-based planning approach calculates risk at an asset level, creating an Asset Risk Model. The Asset Risk Model is a tool used in the development of IPL's TDSIC projects. The Asset Risk Model identifies high-risk assets using asset condition, survivor curves, and consequence of failure criteria for the T&D system and calculates the risk reduction benefit of replacing those assets. Specifically, the model quantifies the expected risk reduction of higher-risk assets over the 7-year TDSIC planning period from 2020 through 2026. The quantitative risk assessment provided by the Asset Risk Model provides transparency and logic to a replacement planning program.

Table 1-2 provides a summary of the assets and asset counts included in the Asset Risk Model.

Table 1-2: T&D Assets in Risk Model Summary

Asset Type	Units	Total
Breakers	Count	1,359
Power Transformers	Count	217
Batteries	Count	114
Transmission and Sub-Transmission	circuit miles	1,135
Overhead Primary Distribution	circuit miles	3,677
Underground Primary Distribution	circuit miles	3,977

1.3 'Do Nothing' Risk Results

The 'Do Nothing' scenario represents the increase in risk for the assets in the Asset Risk Model if no assets are replaced during the 7-Year planning period. This provides a baseline for comparing investment scenarios and their impact to IPL's system risk. This approach is appropriate because few utilities, including IPL, have a long-term (5 to 10 year) baseline for capital improvements with specific projects. 'Do Nothing' scenarios are routinely used to perform analysis such as that presented in this report.

Figure 1-2 and Figure 1-3 show the asset and circuit counts within the risk grid results of the 'Do Nothing' risk scenario in 2026 for substations and circuits, respectively. Section 4.0 provides additional analysis, results, and context of the 'Do Nothing' Scenario risk results. The following outlines the high-level results of the 'Do Nothing' Scenario.

- Total risk level for the 1,690 substation assets in 2026 is approximately 412,000, and approximately 4,065,000 for the 628 circuits (8,364 miles) for a total system risk score of 4,477,000. Risk levels are calculated by summing the risk for each asset, where risk is the product of the individual LOF and COF of each asset.
- The total portfolio system risk increased approximately 23.1 percent from 2019 to 2026 (see Section 4.4 for details).
- The total risk for the 411 assets (COF x LOF) in the High-Risk Region is approximately212,000, or approximately 51 percent of the total 2026 substation risk. The 147 circuits in the High-Risk Region have a risk of approximately 1,485,000, or approximately 37 percent of the total 2026 circuit risk.

Figure 1-2: 2026 Substation Asset Count Heat Map

		2026 'Do Nothing' Risk Profile Asset Count					Total
Likelihood of Failure	Very High - 5	0	2	5	[illegible]	[illegible]	200
	High - 4	[illegible]	2	4	104	[illegible]	224
	Moderate - 3	[illegible]	[illegible]	7	210	294	528
	Low - 2	[illegible]	[illegible]	1	122	109	243
	Remote - 1	[illegible]	[illegible]	[illegible]	238	244	495
	Total	1	36	25	722	906	[illegible]
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
		Consequence of Failure					

411 assets, or 24%, in High-Risk Region.

Figure 1-3: 2026 Circuit Count Heat Map

		2026 'Do Nothing' Risk Profile Circuits Count					Total
Likelihood of Failure	Very High - 5	0	0	0	[illegible]	[illegible]	5
	High - 4	[illegible]	0	0	0	[illegible]	142
	Moderate - 3	[illegible]	[illegible]	3	5	256	264
	Low - 2	[illegible]	[illegible]	2	15	155	173
	Remote - 1	[illegible]	[illegible]	[illegible]	1	38	44
	Total	0	5	6	21	596	[illegible]
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
		Consequence of Failure per Mile					

147 circuits, or 23%, in High-Risk Region.

1.4 Investment Scenarios

Three different investment approaches were modeled within the Asset Risk Model to calculate the resulting risk reduction benefit:

- IPL Seven-Year TDSIC Risk-Based Scenario (IPL TDSIC Risk-Based Scenario) – This investment case relies on the Asset Risk Model and invests capital to replace high-risk assets and maximize risk reduction benefit per dollar invested.
- LOF 4 Scenario – This investment scenario uses an asset's expected remaining life to prioritize investments and replace, over the 7-year period, all assets that fall within the LOF 4 (High) and 5 (Very High) categories in 2026. In other words, the Asset Risk Model replaces any asset that has a LOF above 60 percent. This scenario does not consider asset consequence.

- LOF 5 Scenario – This investment scenario uses an asset's expected remaining life to prioritize investments and replace, over the 7-year period, all assets that fall within the LOF 5 (Very High) category in 2026. In other words, the Asset Risk Model replaces any asset that has a LOF above 80 percent. This scenario does not consider asset consequence. Compared to the LOF 4 scenario, the LOF 5 scenario accepts more risk while lowering the required investment.

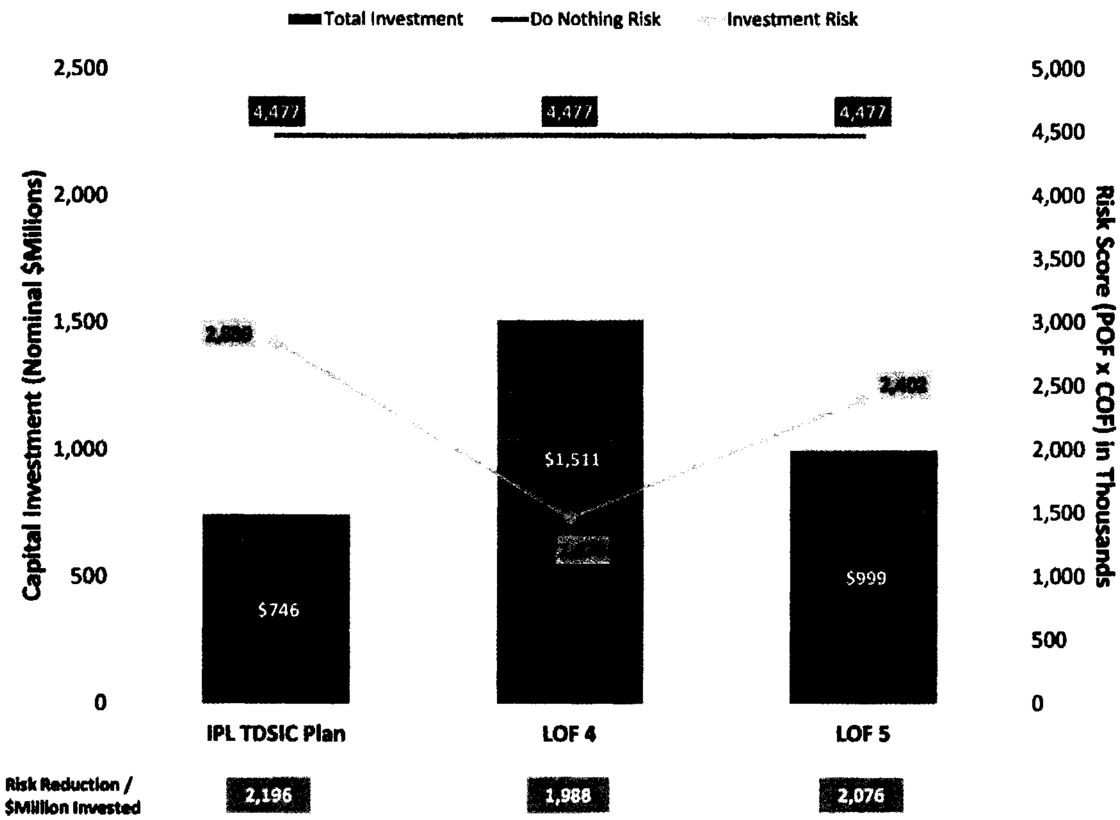
Further details on each of these scenarios are provided in Section 5.2. It should be noted that the Risk-Based Scenario includes risk results and investment levels for the following plans of IPL's TDSIC Plan:

- Substation Assets Replacement
- Circuit Rebuilds
- 4kv Conversion
- XLPE Cable Replacement
- Remote End – Breaker Relay/Upgrades

1.5 Business Case Summary

Section 5.0 describes in more detail the annual capital investments, risk before and after investment, and the business case summary for each of the investment scenarios outlined above. Figure 1-4 shows the results of the three investment scenarios. The red line represents the 'Do Nothing' risk results while the green line represents the resulting 2026 risk score of each scenario investment plan. The blue bars show the total 7-year investment for each scenario. The orange box shows the capital efficiency of the investment scenario in terms of risk reduction per million dollars invested.

Figure 1-4: Scenario Risk and Investment Summary Results



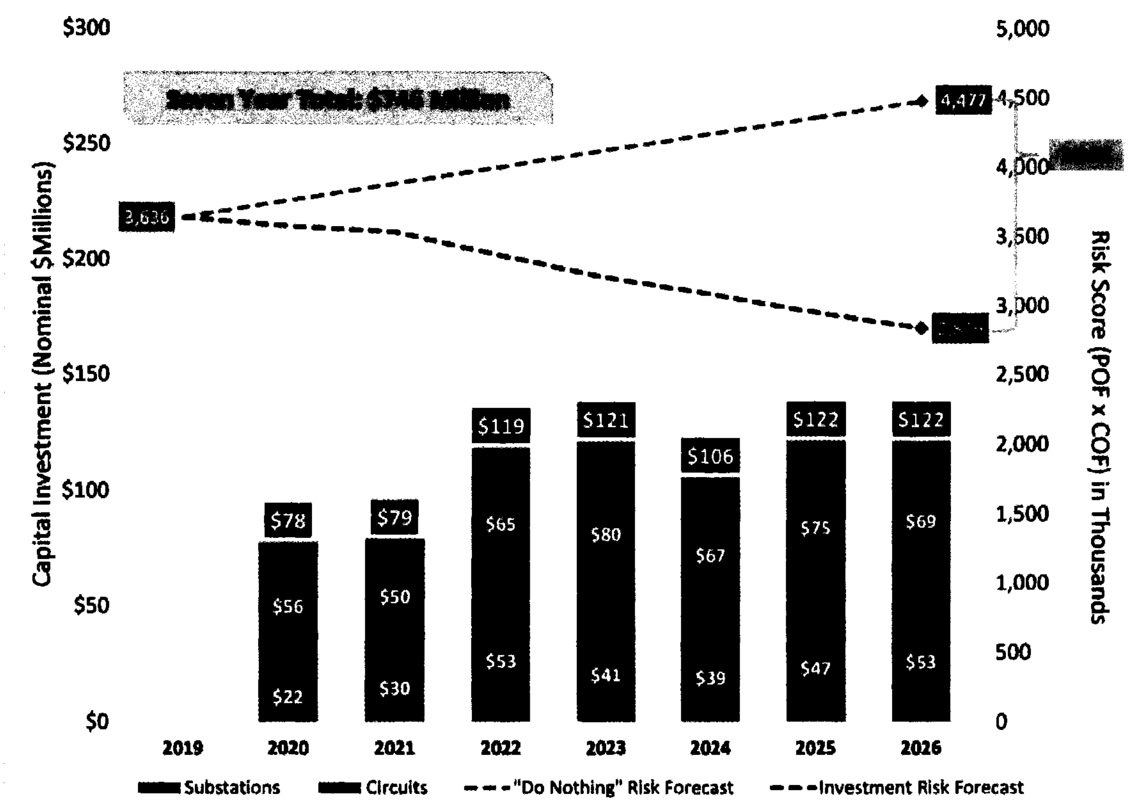
The figure and sections above show the following:

- The age-based investment scenarios LOF 4 and LOF 5 require more capital investment than the IPL TDSIC Plan scenario, $765 million and $253 million more for LOF 4 and LOF 5 scenarios, respectively.
- The IPL TDSIC Plan has the highest risk reduction efficiency of 2,196
- The IPL TDSIC Plan scenario replaces all the substation assets in the High-Risk Region. While the IPL TDSIC Plan does not remove all the circuits from the High-Risk Region, this is due to execution constraints. The LOF 4 plan removes all the substation assets from the High-Risk Region while the LOF 5 still have 159 assets. The LOF 4 and LOF 5 scenarios remove all or nearly all the circuits from the High-Risk Region.
- The IPL TDSIC Plan incorporates the other factors and constraints identified in Section 5-2 (e.g. project coordination, MISO outages, contractor limits) to execute investments over the 7-year period.

- While the LOF 4 and LOF 5 scenarios have more risk reduction than the IPL TDSIC Plan scenario, they come at a significantly higher cost and lower risk reduction per dollar invested. The LOF 4 and LOF 5 scenario capital efficiencies (1,988 and 2,076, respectively) are less than that of the IPL TDSIC Plan (2,196).

As discussed throughout the report, IPL utilized a risk-based planning approach in creating a 7-year TDSIC capital plan with the goal of managing high-risk assets and providing economic risk reduction. The IPL TDSIC Plan manages the risk with all the assets in the High-Risk Region up to IPL's executable constraints, while achieving the highest capital efficiency and spending less than the LOF 4 and LOF 5 scenarios. Figure 1-5 shows the annual details of the IPL TDSIC Plan. The Risk-Based Scenario includes a total of $746 million with a risk reduction of 36.6 percent.

Figure 1-5: IPL TDSIC Risk-Based Scenario Capital Investment vs. Risk Profile



2.0 RISK BASED PLANNING APPROACH

IPL utilized a risk-based planning approach to prioritize investment in the T&D system. While risk-based planning approaches have many purposes, two key purposes for the Asset Risk Model are:

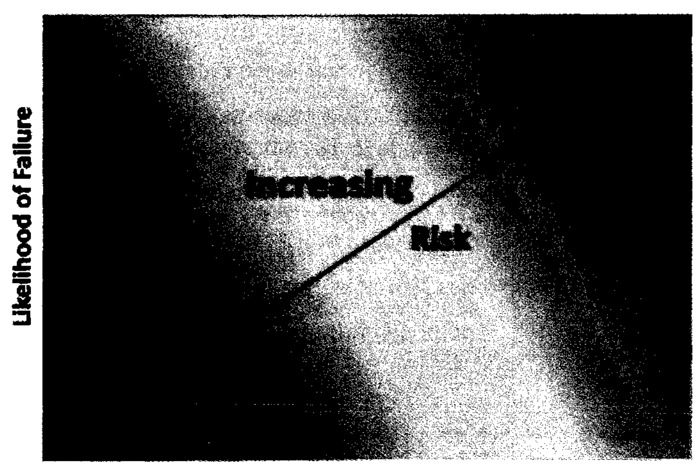
1. Identify high-risk assets and establish a plan to manage the risk.
2. Identify the highest risk reduction per dollar invested for the system.

The risk-based planning approach calculates the risk at an asset level, thus creating an Asset Risk Model, which IPL used as a tool in the development of the TDSIC projects. The Asset Risk Model identifies high-risk assets for the T&D system using asset condition, age, and consequence and calculates the risk reduction benefit of replacing those assets. Specifically, the model quantifies the expected risk reduction over the 7-year TDSIC planning period from 2020 through 2026.

2.1 Risk and Risk Management

In aligning with best practice asset management and ISO 31000, the Asset Risk Model defines risk for an asset as being the product of the likelihood of failure and the consequence or impact caused by the failure. Typically, risk results are visualized using a risk grid/matrix, or heat map. An example risk grid is show in Figure 2-1 below.

Figure 2-1: Risk Matrix



Similarly, the Asset Risk Model adheres to best practice and ISO standards for risk management. The basic framework for the risk assessment follows the process below:

- Risk identification – the asset register, asset definition, and expected asset failure mode
- Risk assessment – consequence and likelihood frameworks including asset health
- Risk mitigation measure development – asset replacements and project bundling
- Risk mitigation measure implementation – executing the mitigation plan

The remaining sub-sections describe the risk identification and the approach to the risk assessment in development of the Asset Risk Model. Section 3.0 provides the results of the risk assessment, and Section 5.0 shows the risk management approach and results in creating IPL's 7-year TDSIC Risk-Based Scenario. The Asset Risk Model uses the process and approach outlined above for assessing risk.

2.2 Likelihood of Failure (LOF) Forecast

The Asset Risk Model forecasts the LOF for each asset assuming an age-based failure event that requires the asset to be replaced. In other words, the Asset Risk Model forecasts the 'end-of-life' failure event. Survivor curves are widely used in the utility industry and asset management organizations to forecast the likelihood of this type of failure event. The Asset Risk Model uses survivor curves to forecast the LOF for each asset. Additionally, the Asset Risk Model uses asset condition information to calculate asset health and represent differences between chronological age and actual deterioration. More simply, the Asset Risk Model uses asset specific condition information to determine an asset's 'effective' age. The following sections provide more detail on survivor curves, calculating LOF, and incorporating asset health to determine an asset's 'effective' age.

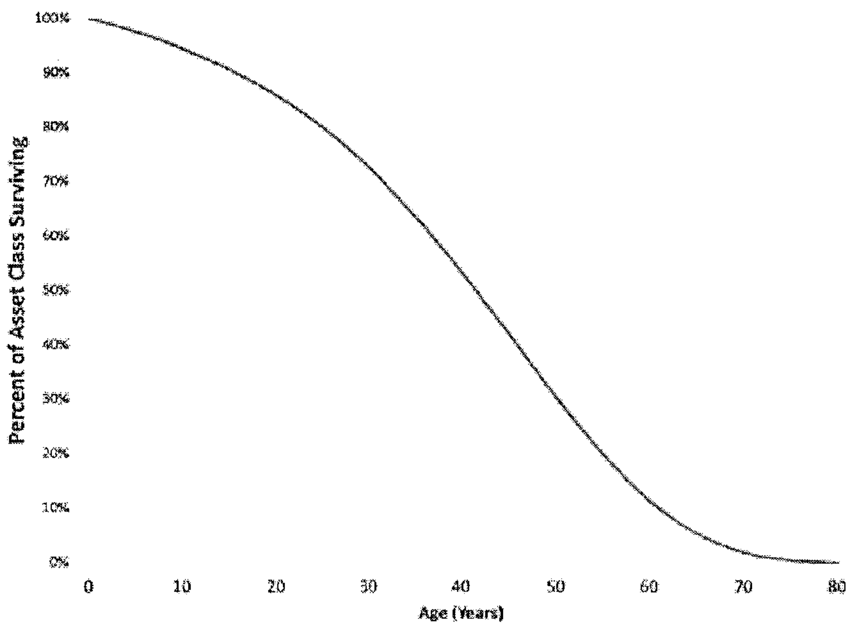
2.2.1 Survivor Curves

Survivor curves are commonly utilized in asset management solutions to forecast LOF by estimating the percentage of a population in an asset class that is surviving over time. Since most utilities work to prevent failures, there is simply not enough actual historical failure data to perform a statistical analysis and develop deterioration curves. As such, Iowa Survivor Curves are utilized to model asset class survivability and calculate the LOF over time. Iowa Survivor Curves are widely used in the utility industry in depreciation studies for establishing rates.

The Asset Risk Model designates an Iowa Survivor Curve for each asset class. Survivor curves were assigned to each asset class based on IPL's 2017 Depreciation Study[3] in addition to industry knowledge of expected life of various asset classes and IPL's experience with asset expected life. Figure 2-2 shows an example survivor curve for substation breakers.

[3] This depreciation study was presented to the Commission in Cause No. 45029.

Figure 2-2: Example Survivor Curve for Substation Breakers



2.2.2 Likelihood of Failure (LOF) Calculation

The LOF forecast for an asset is calculated using the percentage surviving, as noted on the y-axis of the survivor curve, and the effective age of an asset (approach described below). One important note, the LOF calculation is forward looking and disregards the part of the survivor curve that is younger than the asset's effective age. Figure 2-3 illustrates this concept for an example 138 kV Breaker. As the figure shows, the part of the curve before age 30 is not considered in calculating the forecast.

A survivor curve is used to calculate the discrete failure likelihood for each year for the asset. Then, these discrete likelihoods are totaled for a given, forward-looking timeframe to forecast the LOF for the next 10 years. Table 2-1 provides an example calculation for a 30-year-old asset with a LOF horizon of 10 years.

Figure 2-3: LOF Calculation Example – 138 kV Breaker

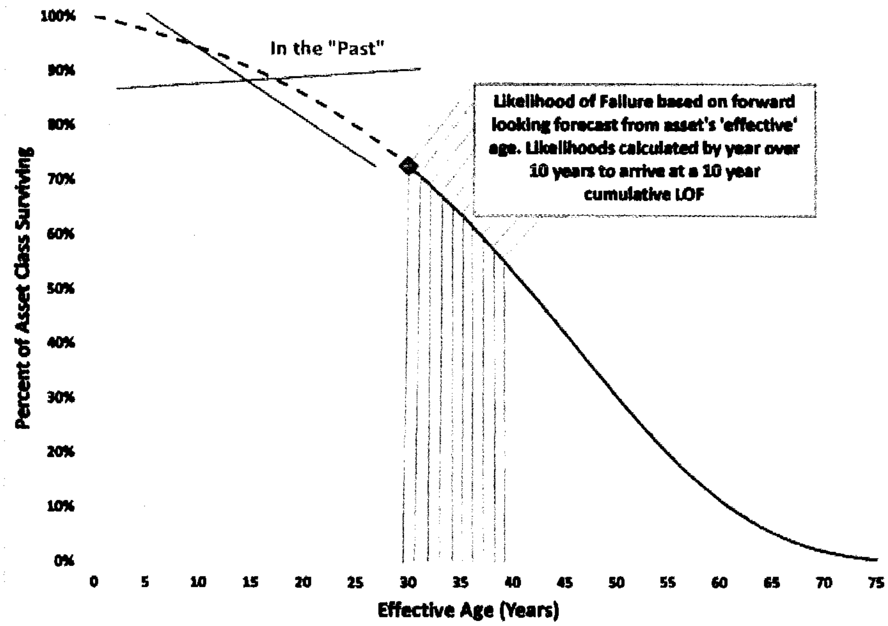


Table 2-1 Example LOF Calculation – 138 kV Breaker

Age	Forecast Year	Discrete LOF	Cumulative LOF
31	1	2.27%	2.27%
32	2	2.35%	4.62%
33	3	2.44%	7.06%
34	4	2.53%	9.59%
35	5	2.62%	12.21%
36	6	2.70%	14.91%
37	7	2.78%	17.69%
38	8	2.86%	20.55%
39	9	2.94%	23.49%
40	10	3.00%	26.49%

2.2.3 Estimating Effective Age

Where available, an asset's condition, coupled with an understanding of the asset's various failure modes, provides a better data set for estimating an asset's remaining useful life. Understanding the remaining useful life allows the analysis to account for older assets that may have more years left on their life than would otherwise be assumed based on their age, and vice versa. The practice of updating an asset's chronological age to reflect condition data yields an asset's 'effective' age. An asset's condition is affected by several factors. The following list includes many of the common factors:

- Loading and Cycling
- Operations
- Maintenance (quality, type, and frequency) and service history
- Animals and insects
- Weathering (temperature, wind, snow/ice, rain, lightening etc.)
- Defects caused by external events (human)
- Combination of the above

2.2.3.1 Asset Health Index (AHI) Approach

An AHI is an indexed score of an asset's relative health based on several measures that incorporate condition information. The Asset Risk Model calculates an AHI score for power transformers, breakers, and wood poles. The Asset Risk Model utilizes IPL's existing AHI framework and asset scoring for power transformers and breakers. Additionally, the Asset Risk Model utilizes Burns & McDonnell's framework and scoring for wood poles. It should be noted that IPL has shared the AHI framework for power transformers and breakers in recent collaborative efforts with IPL Stakeholders[4].

In general, the Asset Health Framework includes several categories, each weighted to calculate the final Asset Health Score. The weighting is included to reflect the relationship between the Asset Heath metric and the asset's condition. Each Asset Health Score measures the relative condition of the asset based on the following general ratings:

- Very High
- High
- Moderate
- Low
- Remote

Figure 2-4 shows a summary of the AHI approach employed for power transformers. Scoring based on this framework was applied to all 217 power transformers. IPL used condition monitoring data (e.g. DGA) as well as the knowledge and experience of IPL subject matter experts to provide scores for all the power transformers.

[4] See Footnote 2

Figure 2-4 Power Transformer AHI Approach Summary

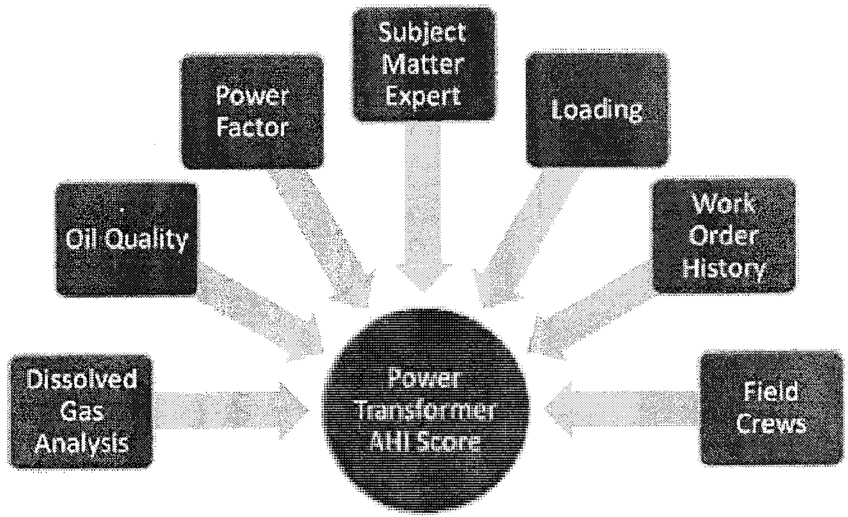
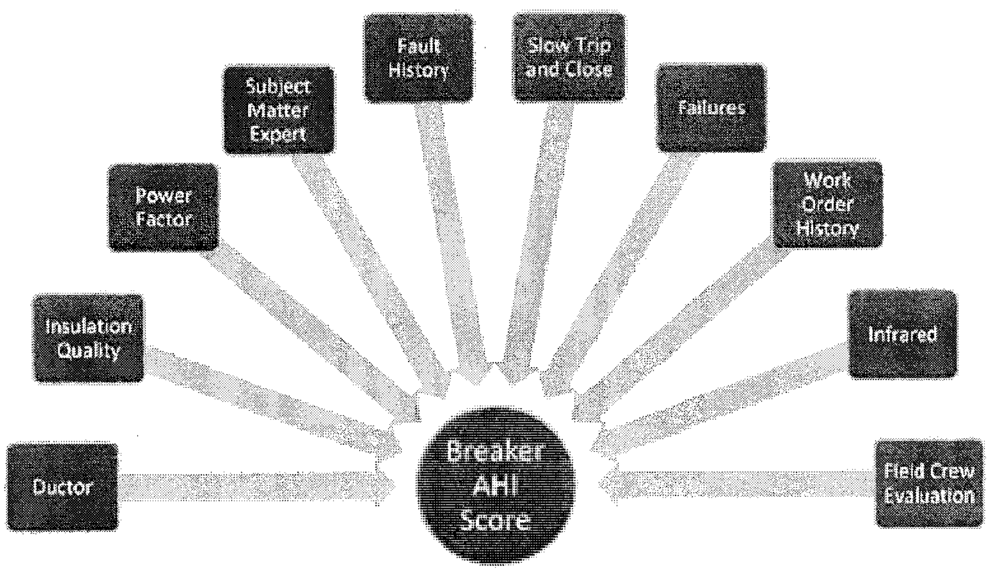


Figure 2-5 provides a summary of the AHI approach for substation breakers. As noted above, this framework was largely developed by IPL, normalized by Burns & McDonnell, and shared with the Commission and other interested parties in the recent collaborative effort[5]. Similar to the power transformers, this framework was used to calculate AHI scores for 1,359 breakers. Scoring of the breakers followed a similar approach as the power transformers.

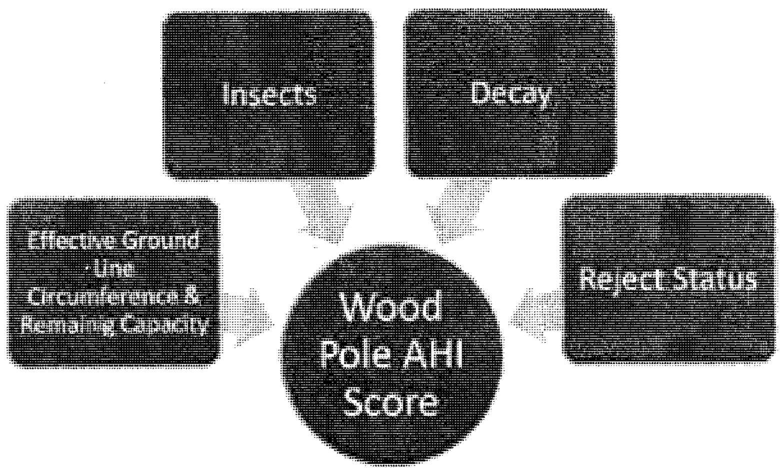
Figure 2-5 Breaker AHI Approach Summary



[5] See Footnote 2

For wood poles, the Asset Risk Model utilizes Burns & McDonnell's asset health framework. Burns & McDonnell utilized IPL's pole inspection information to determine the asset health for 138,256 poles. Pole inspections for IPL are done on a 10 year cycle. During the inspections, every pole is visually inspected and measured. Some assets have more detailed inspections performed, including boring or underground testing. Figure 2-6 provides a summary of the wood pole AHI approach. Scoring for all 138,256 poles was based on the wood pole AHI framework and wood pole inspection at the individual pole level.

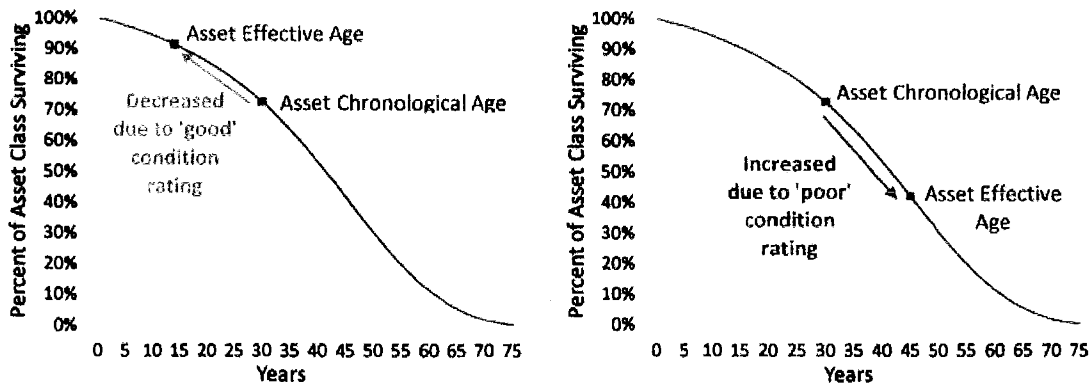
Figure 2-6 Wood Pole AHI Approach Summary



2.2.3.2 Applying Effective Age

Using the asset health indices, the asset's location on the survivor curve is adjusted to reflect their condition. Better than expected condition is used to adjust the asset age so it is younger than its chronological age, and vice versa. Figure 2-7 illustrates how 'effective' age is used to adjust an asset's chronological age based on 'good' and 'poor' condition ratings, respectively.

Figure 2-7 Effective Age Example



In general, the average asset age decreased with the AHI approach. his means that the AHI approach moved more assets from the higher L F to the lower L F regions of the heat matrix, thereby reducing the amount of investment recommended per the Asset Risk Model.

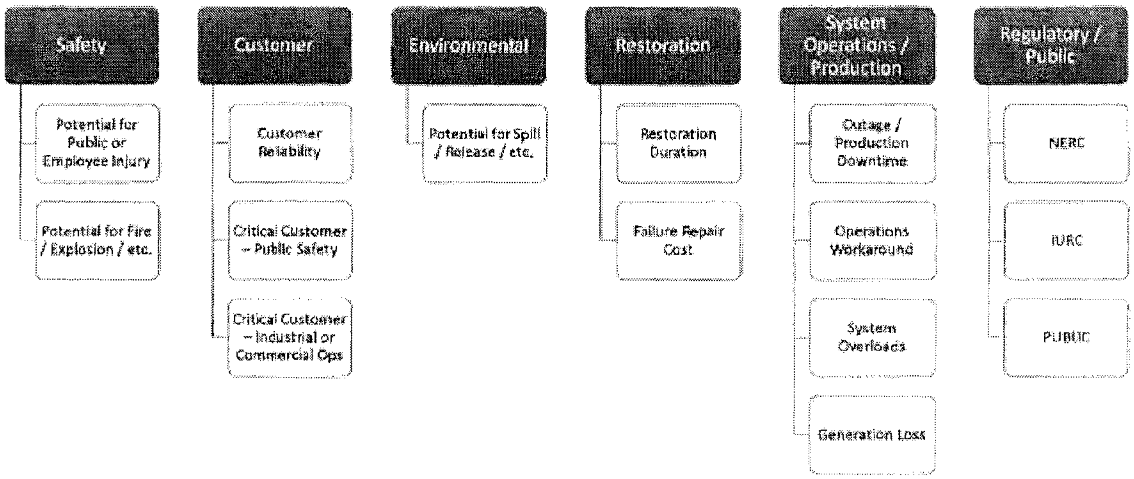
2.3 Consequence of Failure (COF)

his section describes the development of the F framework for IPL. IPL has an existing conse uence framework for transformer and breaker assets. he framework for these assets was initially developed by IPL staff and was recently reviewed in a collaborative effort with IPL Stakeholders . Burns & McDonnell leveraged IPL's existing conse uence framework for transformers and breakers and adjusted Burns & McDonnell's own framework for distribution circuits to create a global and holistic framework, applicable to all asset classes.

o weighting factors are applied across the framework, rather the magnitude of the conse uence scoring framework has been designed to reflect the relative difference in conse uence for an overhead distribution section versus a high voltage breaker. For example, the conse uence framework includes scores as low as 6.6 for a distribution section and scores as high as 700 for a large high voltage breaker.

he F framework for each asset class includes the following categories 1 safety, 2 customer, 3 environmental, restoration, 5 systems operations production, and 6 regulatory public. he F criteria in the Asset Risk Model are presented in Figure 2-8.

Figure 2-8 Consequence of Failure Criteria



All assets in the Asset Risk Model are scored against this framework. For the substation assets power transformers, breakers, and batteries most of the asset scoring was provided by IPL. ith a manageable number of substation assets, IPL staff scored each asset manually, while some of the criteria were filled out using existing data sources. However, with the large number of circuit assets, existing data sources were leveraged i.e. database of circuit assets serving critical customers, database of poles with pole mounted transformers along with some manual input.

An example breaker conse uence score calculation is shown in able 2-2. he framework is configured with categories and subcategories. For scoring, the maximum subcategory score is taken as the category score and is used in the final calculation for an asset's F. he maximum value in each category is summed for a total conse uence score of 700.

he Asset Risk Model also aligns each conse uence score to one of the following conse uence ratings for alignment to the risk grid, which is discussed further in Section .0 and 5.0.

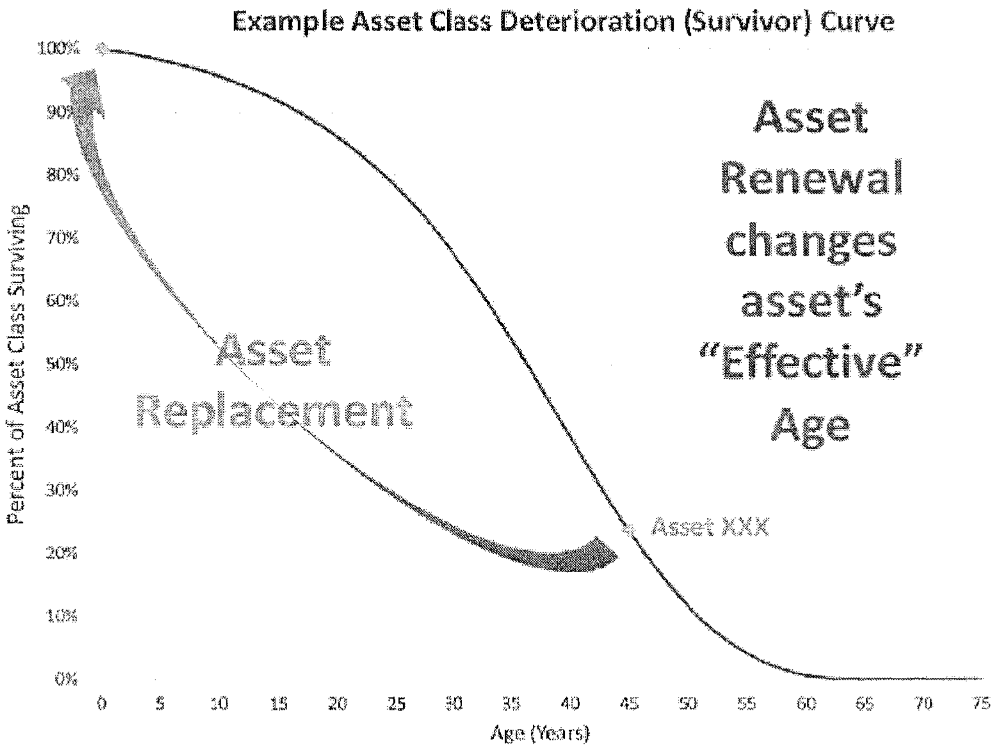
- ery Low 1
- Low 2
- Moderate 3
- High
- ery High - 5

Table 2-2: 138 kV Breaker (Allison #4 Bus Tie)

Consequence Category	Consequence Subcategory	Score	Max
Safety	Potential for Public or Employee Injury	250	250
	Potential for Fire/Explosion/etc.	250	
Customer	Customer Reliability	0	50
	Critical Customer	0	
	Industrial Customer	50	
Environmental	Potential for Spill / Release / etc.	50	50
	Impact of Spill / Release / etc.	50	
Restoration	Restoration Duration	35	150
	Failure Repair Costs	150	
Productivity/Reliability	Outage / Production Downtime	2	100
	Operations Workaround	100	
	Control Contingency Overloads	100	
	Generation Loss	0	
Regulatory/Company Image	NERC	0	100
	IURC	0	
	Public	100	
Criticality Score	**Total**		700

2.4 Risk Reduction and Residual Risk

Figure 2-9: Survivor Curve and Asset Replacement



Using this approach, the Asset Risk Model calculates the residual risk of the asset. Table 2-3 provides an example calculation for the residual risk of the replacement for a zero-year-old 138 kV breaker. Comparing Table 2-1 and Table 2-3 shows a total LOF reduction of 20.93 percent (from 26.49 percent to 5.56 percent) if the asset is replaced in the first year of the forecast period.

Table 2-3 Example LOF Calculation for Asset Replacement – 138 kV Breaker

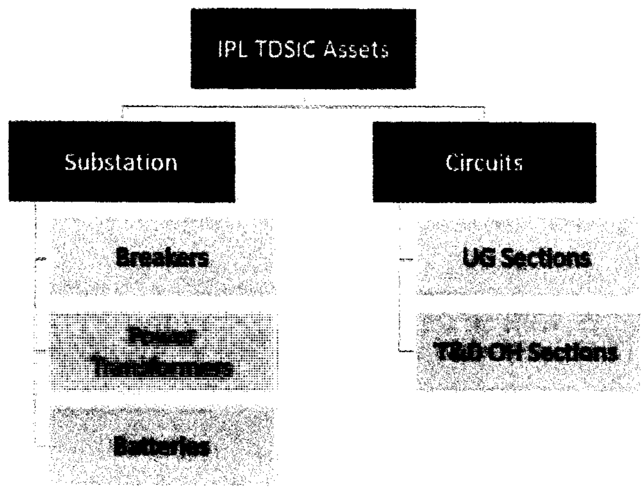
Age	Forecast Year	Discrete LOF	Cumulative LOF
1	1	0.45%	0.45%
2	2	0.47%	0.92%
3	3	0.49%	1.41%
4	4	0.52%	1.93%
5	5	0.54%	2.47%
6	6	0.56%	3.03%
7	7	0.59%	3.62%
8	8	0.62%	4.24%
9	9	0.65%	4.88%
10	10	0.67%	5.56%

In general, asset replacements do not impact COF, however, for a few asset classes risk is also reduced through a decrease in the COF score. Oil circuit breakers and certain types of conductor (covered) include a decrease in environmental and safety scores respectively.

3.0 OVERVIEW OF T&D ASSETS IN RISK MODEL

A critical first step in building an asset risk model is defining what constitutes an 'asset'. This provides the appropriate boundary for understanding the failure mode of an asset. Figure 3-1 depicts the individual asset classes that are included in the Asset Risk Model organized by substation and circuit categories. Specifically, the asset classes include breakers, power transformers, batteries, underground sections, and transmission and distribution overhead sections.

Figure 3-1: TDSIC Asset Class Configuration



3.1 Substation Assets

The substation assets evaluated as part of the TDSIC modeling include IPL's breakers, power transformers, and batteries[7]. Table 3-1 presents the count of each of these asset types.

Table 3-1: Substation Asset Type Counts

Asset Type	Total
Breakers	1,359
Power Transformers	217
Batteries	114
Total	**1,690**

The transmission voltage levels of IPL's system include 138 kV and 345 kV. The distribution voltage levels of IPL comprise 4 kV, 13.2 kV, and 34.5 kV (34.5 kV is also sometimes referred to as sub-

[7] While batteries are located throughout the system both in substations and circuits, most are located within substations. For this reason, they have been categorized as a substation asset for purposes of TDSIC planning.

transmission). Table 3-2 includes the detailed counts of the breakers and power transformers of the distribution and transmission voltage levels. The power transformers are categorized using their low side voltages.

Table 3-2: Transmission and Distribution Asset Counts in TDSIC

Voltage Class	Breakers	Power Transformers
Distribution		
4 kV	116	62
13.2 kV	814	133
34.5 kV	164	12
Total Distribution	1,094	207
Transmission		
138 kV	229	10
345 kV	36	0
Total Transmission	265	10
T&D Total	**1,359**	**217**

3.2 Circuits or Linear Assets

The Asset Risk Model includes underground and overhead linear assets for transmission and primary service. Secondary cable was not included in the Asset Risk Model. Table 3-3 shows a summary of the miles of linear assets included in the Asset Risk Model. It should be noted that the table provides circuit miles (i.e. 1 mile of single phase = 1 mile of two phase = 1 mile of three phase), not miles of conductor wire or cable.

Table 3-3: IPL Circuit Summary

Asset Type	Circuit Miles
Transmission and Sub-Transmission	1,135
Overhead Primary Distribution	3,677
Underground Primary Distribution	3,977
Total	**8,789**

The Asset Risk Model defines a linear asset as a section or segment of the system. The following two sections describe in more detail how the sections are generated. Table 3-4 provides a summary of the number of underground and T&D overhead (OH) sections in the Asset Risk Model. Modeling the circuit assets at this level allows for the identification of specific high-risk spans/segments and comparison at the span and segment level across all circuits as opposed to a circuit by circuit comparison. It should be noted that distribution circuits have a wide range of asset ages dependent on system growth and circuit re-configurations. In some instances, the mainline or backbone of a circuit may be relatively young but the ties or laterals are much older because those laterals were moved over to the new circuit backbone when it was built to balance system load. Modeling at the span/segment level provides the necessary granularity circuit by circuit to identify the specific high-risk portions of a circuit to replace.

Table 3-4: TDSIC Linear Asset Summary

Asset Type	Sections	Circuit Section Miles
Underground Sections	57,981	3,977
T&D OH Sections	160,194	4,387
Total	**218,175**	**8,364**

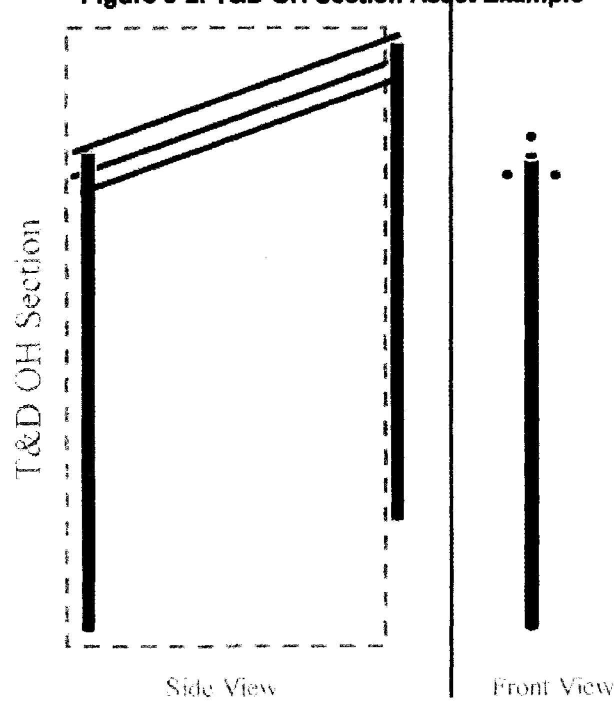
3.2.1 Underground Sections

Underground sections are defined by IPL's GIS application. Burns & McDonnell used IPL's GIS application asset hierarchy for the underground system to generate the underground sections. IPL's GIS application identified these sections based on their beginning and end points, which are typically manholes, vaults, distribution circuit transformers, or other structures.

3.2.2 T&D Overhead (OH) Sections

While the T&D OH system is made of up several types of assets (poles, towers, and wires), the Asset Risk Model defines an overhead linear asset as a single pole/tower (i.e. vertical structure) and the length of the wire(s) from the structure attachment to the spot just before attachment to the next structure. While circuits are electrically separated, many are connected physically through the pole/tower (i.e. double or even triple circuits on a single vertical structure). Figure 3-2 illustrates this approach where a T&D OH Section is a single asset in the Asset Risk Model.

Figure 3-2: T&D OH Section Asset Example



The calculation of risk for each T&D OH Section is the sum of the risk of its parts, the pole or tower and the associated wires (transmission or primary). Table 3-5 provides a summary of the asset base for the T&D overhead section. Every asset is assigned to one of the 160,194 T&D OH Sections.

Table 3-5: Circuit Asset Type Counts

Asset Type	Units	Count
Towers	count	4,065
Wood Poles	count	138,256
Transmission Conductor	circuit miles	1,135
Primary Conductor	circuit miles	7,653

IPL's system comprises various conductor configurations, as illustrated in the Figure 3-3. Each of these configurations represents the type of T&D OH Sections in the Asset Risk Model. While there are dozens of other configurations, the configurations illustrated below generally characterizes most of IPL's system. The configurations include single or double circuits (even triple circuits), two phase or single phase, as well as configurations of both transmission/sub-transmission and distribution. Static and neutral wires have been excluded from the figure.

Figure 3-3: T&D OH Section Configurations (Front View)

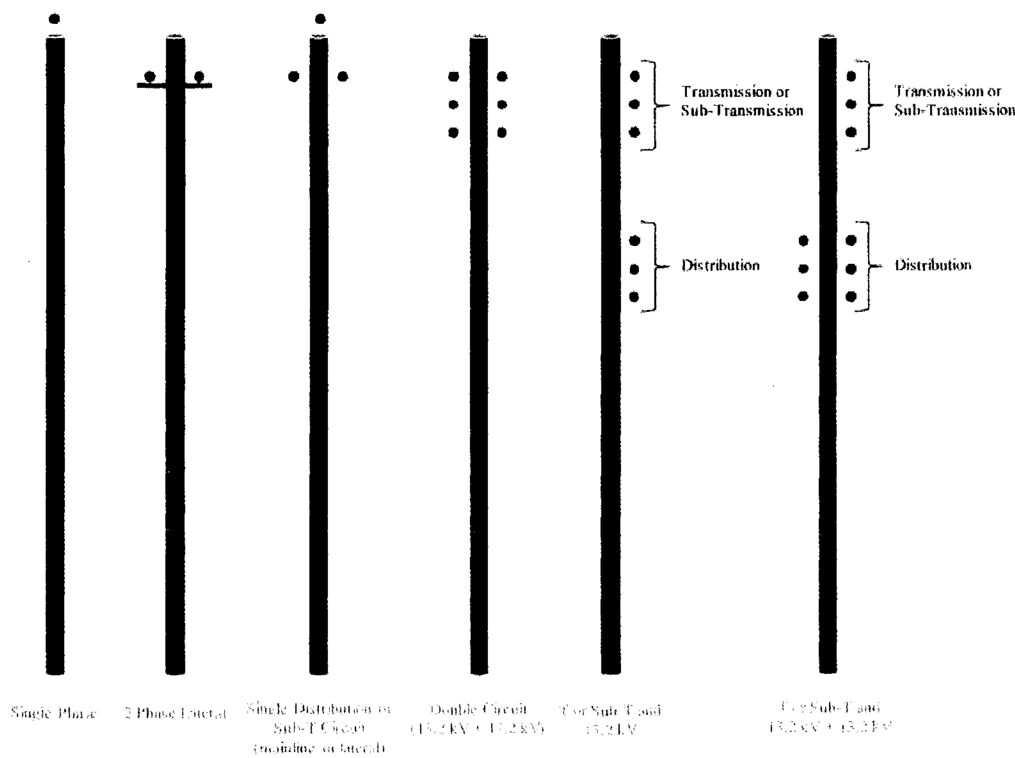


Table 3-6 includes a summary of the most prevalent types of T&D OH Sections as well as the portion of the system that is made up of each type of section.

Table 3-6: T&D OH Section Types

Section Type	Section Miles	Portion of System
13.2 KV - 1 phase	1,385	31.6%
13.2 KV - 3 phase	1,544	35.2%
345 KV	406	9.3%
13.2 KV - 2 phase	220	5.0%
138 KV – tower	114	2.6%
13.2 KV + 13.2 KV	111	2.5%
34.5 KV	101	2.3%
34.5 KV + 13.2 KV	89	2.0%
138 KV – pole	62	1.4%
138 KV + 138 KV	55	1.2%
Other	299	6.8%
Total	**4,387**	**100%**

It should be noted that Table 3-6 and Table 3-4 show the total number of section miles whereas Table 3-3 shows the number of circuit miles. As such, Table 3-6 and Table 3-4 show fewer miles due to several sections including double or even triple circuits.

4.0 'DO NOTHING' SCENARIO

The "Do Nothing' or 'Run-to-Failure' scenario quantifies the increase in risk that IPL carries over time if proactive replacements are not made. This approach involves allowing the assets to age over a 7-year period without replacements. This scenario establishes the baseline to compare the risk reduction for the various investment scenarios outlined in Section 5.0. This approach is appropriate because few utilities, including IPL, have a long-term (5 to 10 year) baseline for capital improvements with specific projects. In the absence of an status quo alternative baseline scenario, the 'Do Nothing' scenario is an appropriate baseline to compare other scenarios. 'Do Nothing' scenarios are routinely used to perform analysis such as that presented in this report.

A key tool to visualize and understand risk is the risk grid/matrix, also known as a heat map. Figure 4-1 provides the risk grid framework used throughout the rest of the report with LOF on the vertical axis, and COF on the horizontal axis. It should be noted that the probabilities on the vertical axis comprise the likelihood of failure over a 10-year period.

Figure 4-1: Risk Grid Framework

			Risk Matrix				
Likelihood of Failure	Very High - 5	80%+					
	High - 4	60% - 80%					
	Moderate - 3	40% - 60%					
	Low - 2	20% - 40%					
	Remote - 1	0% - 20%					
			0 - 100	100 - 200	200 - 300	300 - 400	400+
			Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5
			Consequence of Failure				

Using this visualization tool, asset counts or, alternately, risk scores associated with those asset counts are provided for each of the 25 boxes. As described in more detail in Section 5.0, the location of an asset within the risk grid provides guidance into the type of risk mitigation strategy necessary.

4.1 Assumptions

The analysis assumes the following:

- Assets will be subject to normal ageing over the seven years
- COF ratings remain unchanged over the analysis period

- In the modeling scenario, any repairs done to an asset would restore it to service but would leave the age and service life unchanged
- No new assets are added into the scenario during the 7-year analysis

4.2 High-Risk Region

As mentioned throughout this report, one of the key purposes of risk-based planning for IPL is to manage high-risk assets. IPL identified assets in the 2x2 box located in the upper right-hand corner of the risk grid as high-risk assets, as shown in Figure 4-2. This defined area is also known as the High-Risk Region. This region contains assets with either a high or very high COF and LOF. Section 5.2.2 outlines the approach utilized to manage the risk in this region. The 'Do Nothing' results below highlight the number of assets in this region as well as the risk in this region compared to that of the whole system.

Figure 4-2: Heat Map High-Risk Region

		Risk Matrix				
Likelihood of Failure	Very High - 5				High-Risk Region	
	High - 4					
	Moderate - 3					
	Low - 2					
	Remote - 1					
		0 - 100	100 - 200	200 - 300	300 - 400	400+
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5
		Consequence of Failure				

4.3 'Do Nothing' Risk Assessment

The 'Do Nothing' risk assessment results are presented according to the two key asset bases in the Asset Risk Model, substations (asset count based) and circuits (aggregate of the total circuit miles). The combined risk profile results over the 7 years are provided in Section 4.4.

4.3.1 Substations

Figure 4-3 shows the 2019 'Do Nothing' heat maps for the 1,690 substation assets. As shown in the heat map, there are 244 assets in the High-Risk Region, representing approximately 14 percent of the asset base. As outlined above, these assets are prioritized for mitigation. The figure also shows that most of the assets are in the Moderate to Very High consequence range of the risk grid. The total risk score for the 1,690 substation assets is approximately 320,000. This number is calculated by summing the risk score for every asset where risk is the product of the asset LOF and COF. The total risk for 244 assets in the High-Risk Region is approximately 127,000, or approximately 40 percent of the total substation risk. The

High-Risk Region accounts for 14 percent of the substation asset base, but 40 percent of the substation risk in 2019.

Figure 4-3: 2019 Substation Asset Count Heat Map

		2019 'Do Nothing' Risk Profile Asset Count					Total
Likelihood of Failure	Very High - 5	0	0	0	[illegible]	[illegible]	106
	High - 4	[illegible]	4	5	51	[illegible]	147
	Moderate - 3	[illegible]	[illegible]	3	122	210	349
	Low - 2	[illegible]	[illegible]	[illegible]	190	252	464
	Remote - 1	[illegible]	[illegible]	[illegible]	316	294	624
	Total	1	36	25	722	906	[illegible]
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
		Consequence of Failure					

244 assets, or 14%, in High-Risk Region.

Figure 4-4 shows the heat map in 2026, 7 years later. Since consequence is assumed to remain constant over time, the assets move up the risk grids to higher likelihoods of failure over the period, while keeping constant the number of assets included in each consequence category. The figure shows 411 assets, approximately 24 percent of the substation asset base, in the High-Risk Region, an increase of 167 assets, from 244 to 411, over the 7-year period. That is an increase in the amount of assets within the High-Risk Region of approximately 68 percent.

Figure 4-4: 2026 Substation Asset Count Heat Map

		2026 'Do Nothing' Risk Profile Asset Count					Total
Likelihood of Failure	Very High - 5	0	2	5	[illegible]	[illegible]	200
	High - 4	[illegible]	2	4	104	[illegible]	224
	Moderate - 3	[illegible]	[illegible]	7	210	294	528
	Low - 2	[illegible]	[illegible]	[illegible]	122	109	243
	Remote - 1	[illegible]	[illegible]	[illegible]	238	244	495
	Total	1	36	25	722	906	[illegible]
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
		Consequence of Failure					

411 assets, or 24%, in High-Risk Region.

The total risk for the 1,690 assets in Figure 4-4 is approximately 412,000. That is an increase of approximately 29 percent over the 7-year period. The total risk for the 411 assets in the High-Risk Region is approximately 212,000, or approximately 51 percent of the total 2026 substation risk. Over the 7-year period, the substation risk level in the High-Risk Region increased from 40 percent in 2019 to 51 percent in 2026. In 2026, the High-Risk Region accounts for 24 percent of the substation asset base but 50 percent of the substation risk.

4.3.2 Circuits

This section shows similar results to those in the substation section above. While circuit assets are modeled at the section level, for representation within the heat map the spans have been aggregated to the circuit level and then normalized on a per circuit mile basis to avoid biasing the results for longer circuits. The reason for this approach is the nature of the asset base, distribution assets are critical or strategic on a collective basis, not on an individual basis like many of the substation assets.

Figure 4-5 shows the 2019 'Do Nothing' heat maps for circuits. A circuit's location on the LOF axis is based on the weighted average of the LOF scores for all the sections on the circuit. As an example, the 218 circuits in the Moderate LOF include a section in each of the LOF categories but average out to a Moderate. As shown in the heat map, most of the circuits are in the Moderate to Very High consequence region of the grid and Low to Moderate regions of the likelihood categories. The total 2019 risk for the 628 circuits is approximately 3,316,000. This score is calculated by summing the risk score for all underground and overhead T&D sections for all circuits.

The total risk for 47 circuits in the High-Risk Region is approximately 346,000, or approximately 10 percent of the total circuit risk. The High-Risk Region accounts for 7 percent of the circuit asset base, but 10 percent of the circuit risk in 2019.

Figure 4-5: 2019 Circuit Count Heat Map

		2019 'Do Nothing' Risk Profile Circuit Count					Total
Likelihood of Failure	Very High - 5	0	0	0	[illegible]	[illegible]	2
	High - 4	[illegible]	0	0	0	[illegible]	45
	Moderate - 3	[illegible]	0	0	1	217	218
	Low - 2	[illegible]	[illegible]	3	12	251	267
	Remote - 1	[illegible]	[illegible]	[illegible]	8	81	96
	Total	0	5	6	21	596	[illegible]
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
		Consequence of Failure per Mile					

47 circuits, or 7%, in High-Risk Region.

Figure 4-6 shows the heat map in 2026, 7 years later. Since consequence is assumed to remain constant over time, the circuits move up the risk grids over the period, while keeping constant the number of circuits included in each consequence category. The figure shows 147 circuits, approximately 23 percent of the circuit asset base, in the High-Risk Region. An increase of 100 circuits over the 7-year period. That is an increase in the amount of circuits within the High-Risk Region of 213 percent.

The total risk for the 628 circuits in Figure 4-6 is approximately 4,065,000. That is an increase of approximately 23 percent over the 7-year period. The total risk for the 147 circuits in the High-Risk Region is approximately 1,485,000, or approximately 37 percent of the total 2026 circuit risk. Over the 7-year period, the circuit risk level in the High-Risk Region increased from 10 percent in 2019 to 37 percent in 2026. In 2026, the High-Risk Region accounts for 23 percent of the circuit asset base but 37 percent of the circuit risk.

Figure 4-6: 2026 Circuit Count Heat Map

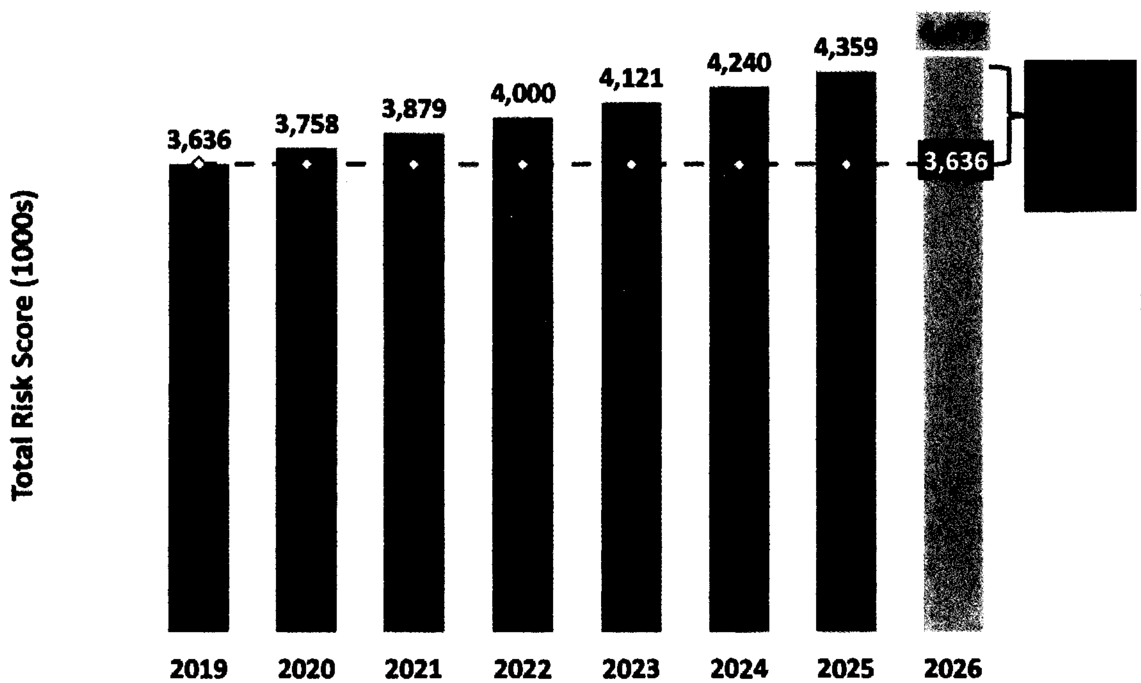
		2026 'Do Nothing' Risk Profile Circuits Count					Total
Likelihood of Failure	Very High - 5	0	0	0	[illegible]	[illegible]	5
	High - 4	[illegible]	0	0	0	[illegible]	142
	Moderate - 3	[illegible]	[illegible]	3	5	256	264
	Low - 2	[illegible]	[illegible]	2	15	155	173
	Remote - 1	[illegible]	[illegible]	[illegible]	1	38	44
	Total	0	5	6	21	596	[illegible]
		Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
		Consequence of Failure per Mile					

147 circuits, or 23%, in High-Risk Region.

4.4 'Do Nothing' Seven Year Risk Profile

Figure 4-7 shows the total risk score profile for both the substation and circuit assets for the 'Do Nothing' scenario from 2019 to 2026. As the figure shows, total system risk increases by approximately 23.1 percent over the 7-year planning period.

Figure 4-7: 'Do Nothing' Risk Forecast, 2019 to 2026



5.0 INVESTMENT SCENARIO RESULTS

5.1 Overview

IPL utilized a risk-based planning approach to prioritize investment in the T&D system. This section will present the investment case scenarios utilized in the TDSIC business case evaluation. The 'Do Nothing' approach (Section 4.0) serves as a baseline for calculating risk reduction benefit. The investment scenario results include the capital outlay in each, the risk before and after investment, and the business case summary.

5.2 Risk Model Scenarios

Three different investment approaches were modeled within the Asset Risk Model to calculate the resulting risk reduction benefit and understand if any assets still exceeded IPL's risk tolerance levels. The three scenarios are:

- IPL Seven-Year TDSIC Risk-Based Scenario (IPL TDSIC Risk-Based Scenario) – This investment case relies on the Asset Risk Model and invests capital to replace high-risk assets and maximize risk reduction benefit per dollar invested.
- LOF 4 Scenario – This investment scenario uses an asset's expected remaining life to prioritize investments and replace, over the 7-year period, all assets that fall within the LOF 4 (High) and 5 (Very High) categories in 2026. In other words, the Asset Risk Model replaces any asset that has a LOF above 60 percent. This scenario does not consider asset consequence.
- LOF 5 Scenario – This investment scenario uses an asset's expected remaining life to prioritize investments and replace, over the 7-year period, all assets that fall within the LOF 5 (Very High) category in 2026. In other words, the Asset Risk Model replaces any asset that has a LOF above 80 percent. This scenario does not consider asset consequence. Compared to the LOF 4 scenario, the LOF 5 scenario accepts more risk while lowering the required investment.

The Risk-Based Scenario includes risk results and investment levels for the following plans of IPL's TDSIC Plan:

- Substation Assets Replacement
- Circuit Rebuilds
- 4kv Conversion
- XLPE Cable Replacement
- Remote End – Breaker Relay/Upgrades

Details on each of these scenarios are provided in the sections below.

5.2.1 4kv Conversion, XLPE Cable Replacement, and Remote End – Breaker Relay Investment Plans

Some systems within IPL's asset base require coordinated investment plans for execution. For instance, the conversion of a 4 kV system to 13.2 kV requires a detailed plan for when each circuit and substation can be retired and cut-over to the new 13.2 kV system. IPL has developed these plans for three such asset bases: 4 kV conversion to 13.2 kV, replacement of the unjacketed direct bury cable, and remote end – breaker relay upgrades project.

The Asset Risk Model is utilized to calculate the expected risk reduction of these three plans. The Asset Risk Model schedules the assets for retirement or replacement within each of these plans based on the year that IPL designated. All three investment scenarios outlined above adopt the plans for these three plans and reflect the same capital investment and risk reduction level.

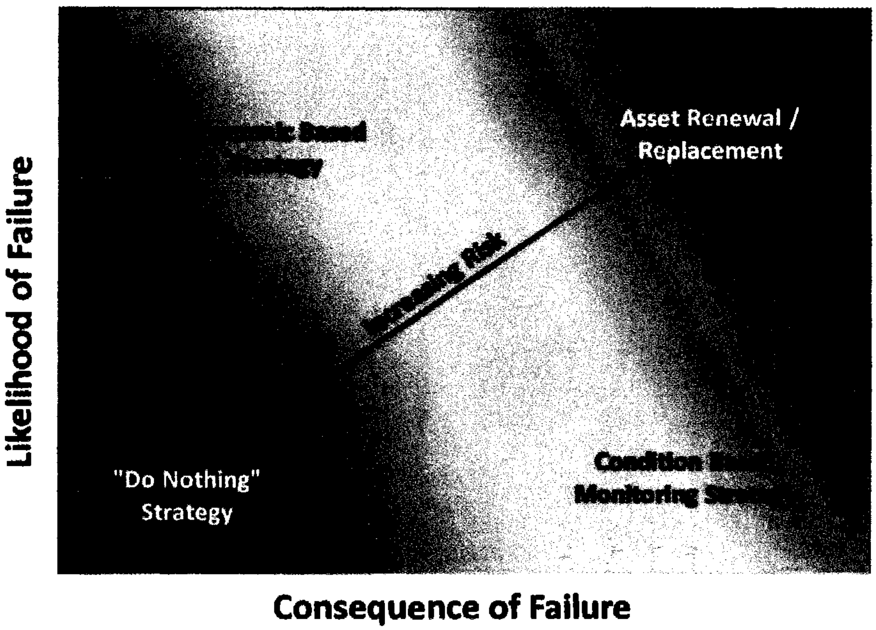
5.2.2 IPL TDSIC Risk-Based Scenario Approach

The IPL TDSIC Risk-Based Scenario utilized a risk-based planning approach to identify and prioritize the assets for replacement based on the overall budget level. Two main goals of the risk-based planning approach for IPL, as mentioned, are:

1. Identify high-risk assets and establish a plan to manage the risk.
2. Identify the highest risk reduction per dollar invested for the system.

Figure 5-1 is a guide for managing risk based on an asset's placement within the risk grid. Assets in the top-right of the grid are high-risk. The risk is managed by replacement of the asset. Assets in the bottom right of the risk grid are high consequence but are relatively healthy. The strategy for these assets is to monitor how their health changes over time. For the assets in the middle to the top left of the risk grid an economic based strategy is employed for managing risk. This means that assets can be chosen for replacement based on available funds and capital efficiency.

Figure 5-1: Risk Management Approach



Any asset with a LOF of High or greater (LOF 4 ≥ 4) and COF of High and greater (COF 4 ≥4) is a high-risk asset and required action to manage the risk. Figure 5-2 shows this region, referred to here as the High-Risk Region. In general, assets in the High-Risk Region are targeted for replacement within the 7-year period.

Figure 5-2: High-Risk Region

Likelihood of Failure	Risk Matrix				
Very High - 5				High-Risk Region	
High - 4					
Moderate - 3					
Low - 2					
Remote - 1					
	0 - 100	100 - 200	200 - 300	300 - 400	400+
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5
	Consequence of Failure				

With the identification and prioritization of the assets in the High-Risk Region, the Asset Risk Model then prioritizes investment selecting assets with the highest risk reduction per dollar invested from the Risk-Investment Efficiency Region. This approach aligns with the second of the two goals of IPL's risk-based planning approach for TDSIC noted above. Figure 5-3 and Figure 5-4 show this region substation and circuit asset bases, respectively. The larger region for the circuits' asset base is due to the nature of how circuit assets are replaced and the potential for risk reduction benefit from a consequence of failure perspective on some of the conductor types. If the area was not expanded for circuits this benefit would not have been realized.

Figure 5-3: Risk-Investment Efficiency Region for Substations

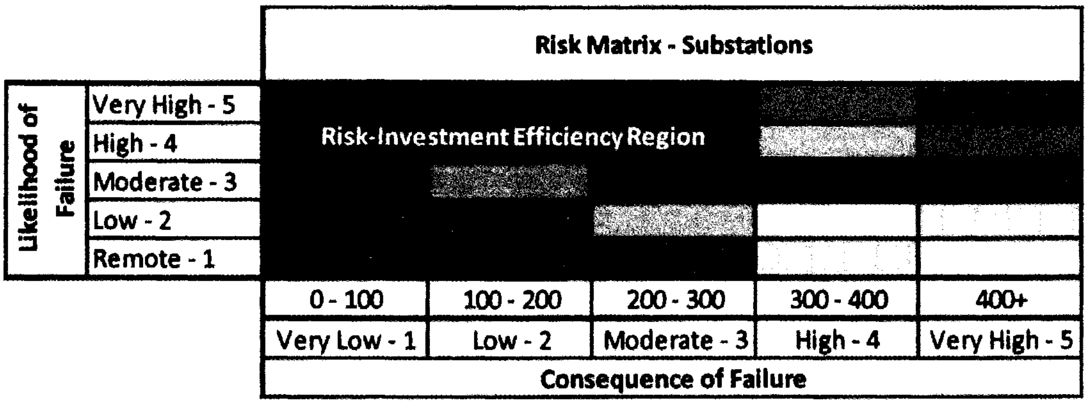
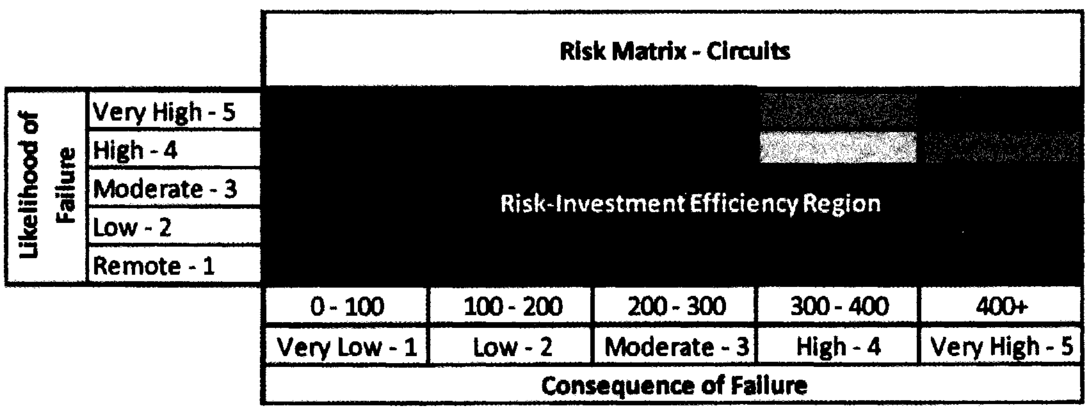


Figure 5-4: Risk-Investment Efficiency Region for Circuits



Additionally, IPL used several other factors and constraints enumerated in the summary below to identify and prioritize assets for replacement to create an executable TDSIC Risk-Based Scenario. In summary, assets were identified and prioritized for replacement based on the following:

- Overall Asset Risk, specifically those assets in the High-Risk Region.
- Risk reduction per dollar invested capital efficiency metric.
- Internal and external resources available to execute investment by asset class and by year.
- Lead time for engineering, procurement, and construction (e.g. large transformers).
- MISO and other agency coordination.
- Asset bundling into projects for work efficiencies.

- Asset replacement coordination (i.e. asset A before asset B, asset Y and asset Z at the same time).
- Asset condition and health.

5.2.3 LOF 4 Scenario Approach

The LOF 4 Scenario is intended to provide a benchmark scenario that represents the risk reduction achieved by proactively replacing old assets, regardless of COF. The LOF 4 Scenario identifies assets for replacement based expected remaining life for the asset. Specifically, the LOF 4 Scenario replaces all assets with a LOF greater than 60 percent, top two rows, by 2026 as shown in Figure 5-5. Based on the figure, the LOF 4 Scenario will replace 424 substation assets over the 7-year period. Within the 7-year period assets are bundled by substation and circuit and prioritized for replacement based on the LOF.

Figure 5-5: LOF 4 Scenario – Targeted Asset Replacements

Likelihood of Failure	2026 'Do Nothing' Risk Profile Asset Count					Total
Very High - 5	0	2	5	[illegible]	[redacted]	200
High - 4	[illegible]	2	4	104	[illegible]	224
Moderate - 3	[redacted]	17	7	210	294	528
Low - 2	[redacted]	[redacted]	[illegible]	122	109	243
Remote - 1	[redacted]	[redacted]	[redacted]	238	244	495
Total	1	36	25	722	906	[illegible]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure					

424 assets replacements in LOF 4 Scenario

The same approach is applied for the circuit assets. Any circuit segment in the LOF 4 or 5 categories by 2026 is scheduled for replacement using the same bundling approach described above. For the LOF 4 Scenario, 2,852 miles (or 99,233 segments), out of a total of 8,364 miles (or 218,175 segments), are in the LOF 4 or 5 categories. The LOF 4 Scenario replaces approximately 34 percent of the system miles or 45 percent of the system segments. It should be noted that this scenario only replaces the segments on all circuits in the LOF 4 or 5 categories, not the entire circuit.

This scenario does not consider many of the other factors and constraints of the IPL TDSIC Risk-Based Scenario noted in Section 5.2.2 above. Section 5.4 shows the results of the investment profile, heat maps post investment, and business case summary chart. It should be noted that this scenario assumes IPL can execute this level of work over the 7-year period. Further, while the IPL TDSIC Risk-Based Scenario includes a high-level schedule coordination effort, the LOF 4 Scenario does not.

5.2.4 LOF 5 Scenario Approach

The LOF 5 Scenario is intended to provide a second benchmark scenario that represents the risk reduction achieved by proactively replacing old assets, regardless of COF. The LOF 5 Scenario is like the LOF 4 Scenario in that assets are identified for replacement based on expected remaining life for the asset. In contrast, the LOF 5 Scenario replaces all the assets by 2026 that have a LOF greater than 80 percent, whereas the LOF 4 Scenario uses a 60 percent threshold for LOF.

Figure 5-6 shows that the LOF 5 Scenario includes the replacement of 200 substation assets. On the circuit side, the LOF 5 Scenario includes the replacement of 1,762 miles (or 64,628 segments), out of a total of 8,364 miles (or 218,175 segments). The LOF 5 Scenario replaces approximately 21 percent of the system miles or 30 percent of the system segments. It should be noted that this scenario only replaces the segments on all circuits in the LOF 5 category, not the entire circuit.

Figure 5-6: LOF 5 Scenario – Targeted Asset Replacements

Likelihood of Failure	2026 'Do Nothing' Risk Profile Asset Count					Total
	Consequence of Failure: Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
Very High - 5	0	2	5	[illegible]	[illegible]	200
High - 4	[illegible]	2	4	104	[illegible]	224
Moderate - 3	[illegible]	[illegible]	7	210	294	528
Low - 2	[illegible]	[illegible]	1	122	109	243
Remote - 1	[illegible]	[illegible]	[illegible]	238	244	495
Total	1	36	25	722	906	[illegible]

200 asset replacements in LOF 5 Scenario.

As noted above, this investment scenario replaces the 4 kV and unjacketed underground assets per the plans established by IPL. This scenario does not consider many of the other factors and constraints of the IPL TDSIC Risk-Based Scenario noted in Section 5.2.2 above. Section 5.3 shows the results of the investment profile, heat maps post investment, and business case summary chart. It should be noted that this scenario assumes IPL can execute this level of work over the 7-year period. Further, while the IPL TDSIC Risk-Based Scenario includes a high-level schedule coordination effort, the LOF 5 Scenario does not.

5.3 IPL TDSIC Risk-Based Scenario Results

This section shows the investment plan, risk heat maps after investment, and business case summary results for the IPL TDSIC Risk-Based Scenario. The approach to selecting the assets and prioritizing for replacement is outlined in Section 5.2.2 above.

5.3.1 IPL TDSIC Risk-Based Scenario Investment Results

Table 5-1 shows the asset replacement schedule throughout the 7-year TDSIC period for the IPL TDSIC Risk-Based Scenario. In total, there are 825 substation asset replacements or retirements and 1,291 section miles of circuits replaced or retired.

Table 5-1: Investment Scenario Replacement Schedule

Asset Category	Units	2020	2021	2022	2023	2024	2025	2026	Total
Power Transformer	[count]	6	5	1	4	7	3	10	36
Breaker	[count]	54	99	114	139	99	110	89	704
Battery	[count]	29	11	15	10	6	5	9	85
Trans + Sub-T	[miles]	0	0	0	0	0	0	0	0
OH - T&D Section	[miles]	69	52	84	95	74	81	72	527
UG Primary	[miles]	109	109	109	109	109	109	109	764

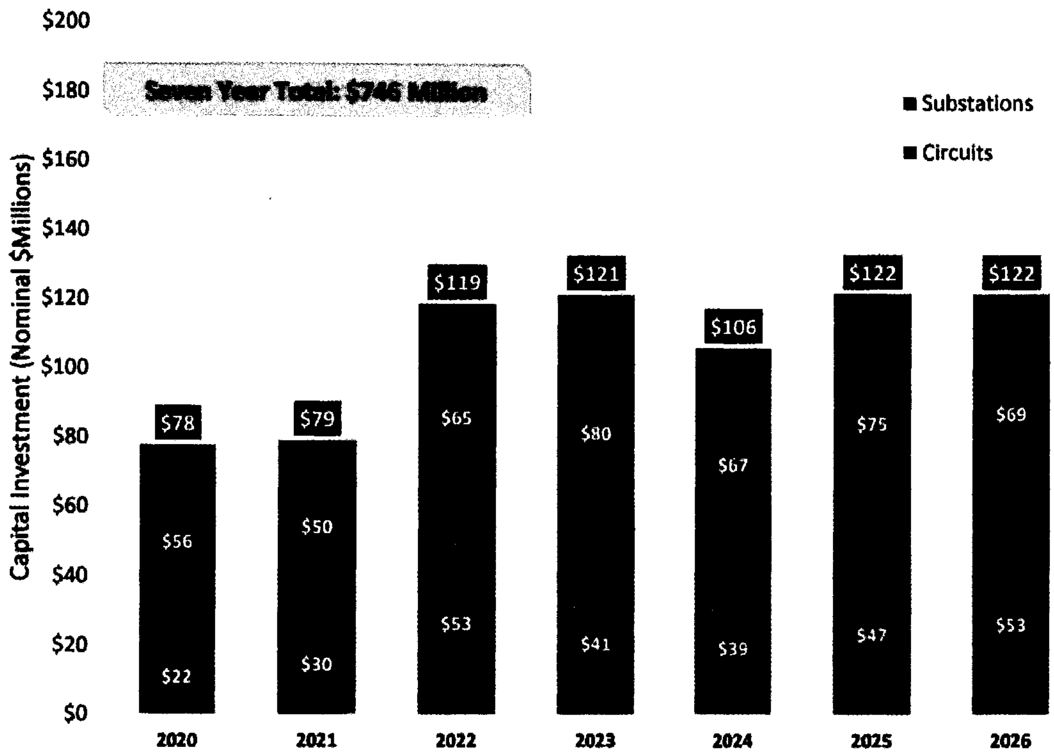
Table 5-2 shows the 7-year total investment by Project Plan category for the asset replacements and retirements shown above.

Table 5-2: IPL TDSIC Risk-Based Scenario Investment Summary

Project Plan	Nominal $millions
4kv Conversion	$92.0
XLPE Cable Replacement	$86.2
Remote End – Breaker Relay / Upgrades	$21.0
Substation Assets Replacement	$248.1
Circuit Rebuilds	$298.7

Figure 5-7 displays the annual capital investment profile of the IPL TDSIC Risk-Based Scenario totaling $746 million. The annual variability is driven by the bundling of assets into projects. The numbers in the chart include investment for the 4 kV conversion, unjacketed replacement plan, breaker remote end and relay project, and the asset replacements identified by the Asset Risk Model. The spend levels for the substation asset replacements and circuit upgrades are based on IPL technical internal limits over the 7-year period.

Figure 5-7: IPL TDSIC Risk-Based Scenario Investment Profile



5.3.2 IPL TDSIC Risk-Based Scenario Risk Results Summary

Section 4.3 includes the heat maps for the substation asset and circuit counts and risk scores for the 'Do Nothing' scenario. The following two figures, Figure 5-8 and Figure 5-9, show the heat maps in 2026 after investment for substations and circuits respectively. The total asset and circuit counts in the figures differ from those in Section 4.3 because of the 4 kV conversion asset retirements.

For the substation assets, IPL's TDSIC Risk-Based Scenario replaces or retires all the assets in the High-Risk Region, it also captures many of the assets immediately outside of the High-Risk Region. The resulting substation system risk in 2026 from the scenario is approximately 147,000, 64.4 percent decrease in risk compared to the 2026 'Do Nothing' scenario.

For the circuit asset base results, shown in Figure 5-9, the resulting system risk in 2026 is approximately 2,692,000, 33.8 percent decrease in risk compared to the 2026 'Do Nothing' scenario. Further the plan removes 124 circuits from the High-Risk Region leaving 23 circuits. Compared to the 2026 'Do Nothing' scenario the plan reduced risk in the High-Risk Region by 93.6 percent to an overall risk level of approximately 95,000. It should be noted that IPL's technical execution limit over the 7 years does not allow them to replace all the sections in the High-Risk Region, causing 23 circuits to remain in the High-Risk Region after 2026. As discussed above, COF typically remains constant over time, but for some asset classes the COF does change with a near 'in-kind' replacement. In the case of the circuit upgrades, some wire types (covered conductor) consequence scores decreased with the replacement to the new equipment standard (bare conductor). This is the reason for circuits moving to lower COF categories.

Figure 5-8: 2026 Substation IPL TDSIC Risk-Based Scenario Asset Count

Likelihood of Failure	2026 Investment Plan Risk Profile Asset Count					Total
Very High - 5	0	1	0	[redacted]	[redacted]	1
High - 4	[redacted]	0	1	0	[redacted]	1
Moderate - 3	[redacted]	[redacted]	3	90	87	186
Low - 2	[redacted]	[redacted]	2	116	146	271
Remote - 1	[redacted]	[redacted]	[redacted]	416	633	1,062
Total	1	17	15	622	866	[redacted]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure					

0 assets, or 0%, in High-Risk Region.

Figure 5-9: 2026 Circuit IPL TDSIC Risk-Based Scenario Circuit Count

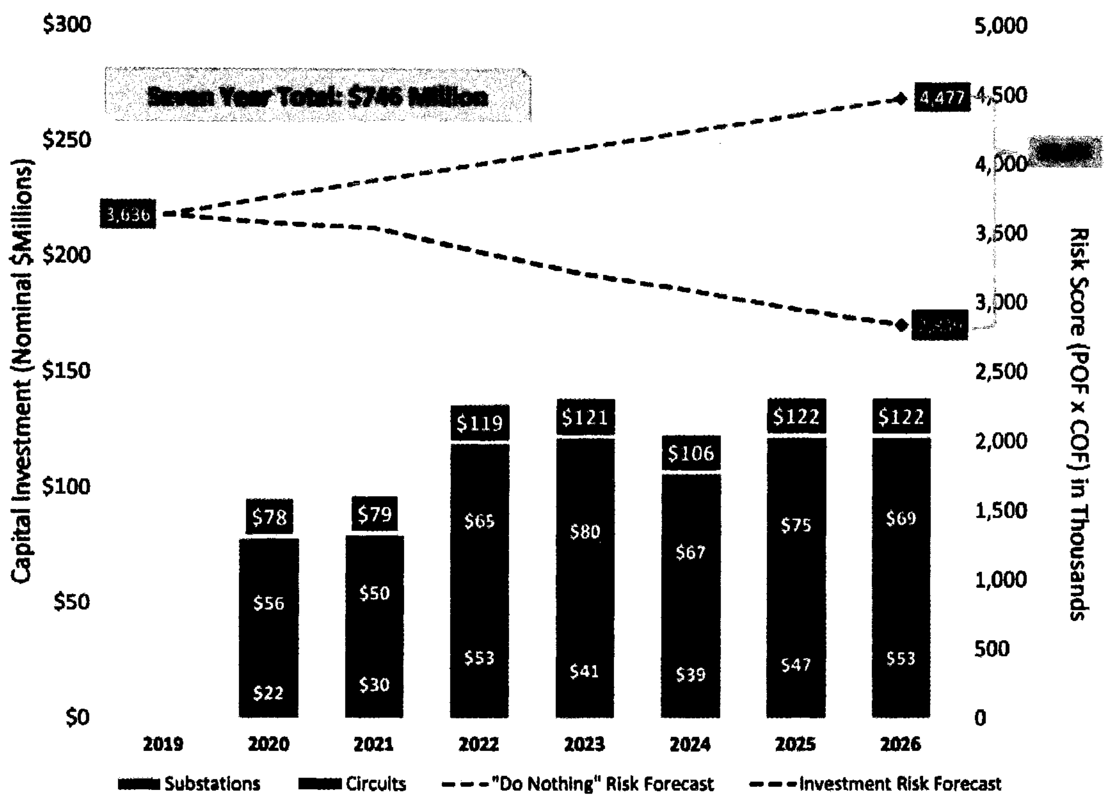
Likelihood of Failure	2026 Investment Plan Risk Profile Circuit Count					Total
Very High - 5	0	0	0	[redacted]	[redacted]	3
High - 4	[redacted]	0	0	0	[redacted]	20
Moderate - 3	[redacted]	[redacted]	3	2	178	183
Low - 2	[redacted]	[redacted]	2	19	286	308
Remote - 1	[redacted]	[redacted]	[redacted]	1	62	68
Total	0	5	6	23	548	[redacted]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure per Mile					

23 circuits, or 4%, in High-Risk Region.

5.3.3 IPL TDSIC Risk-Based Scenario Business Case Summary Results

Figure 5-10 shows the overall business case comparing risk reduction to invested capital for the IPL TDSIC Risk-Based Scenario.

Figure 5-10: IPL TDSIC Risk-Based Scenario Capital Investment vs. Risk Profile



The following highlights some of the main business case points for the IPL TDSIC Risk-Based Scenario:

- Total risk reduction by the end of 2026 (year 7) of 36.6 percent.
- Replacement or retirement of 825 substation assets ($285 million) and 1,291 section miles of circuits ($461 million) for total for investment in capital of $746 million.
- Mitigation of all substation asset risk in the High-Risk Region. In the High-Risk region, 40 circuits remain due to IPL's technical constraints for circuit upgrades over the 7-year period.
- For every million dollars invested, risk is reduced by 2,196 risk points.

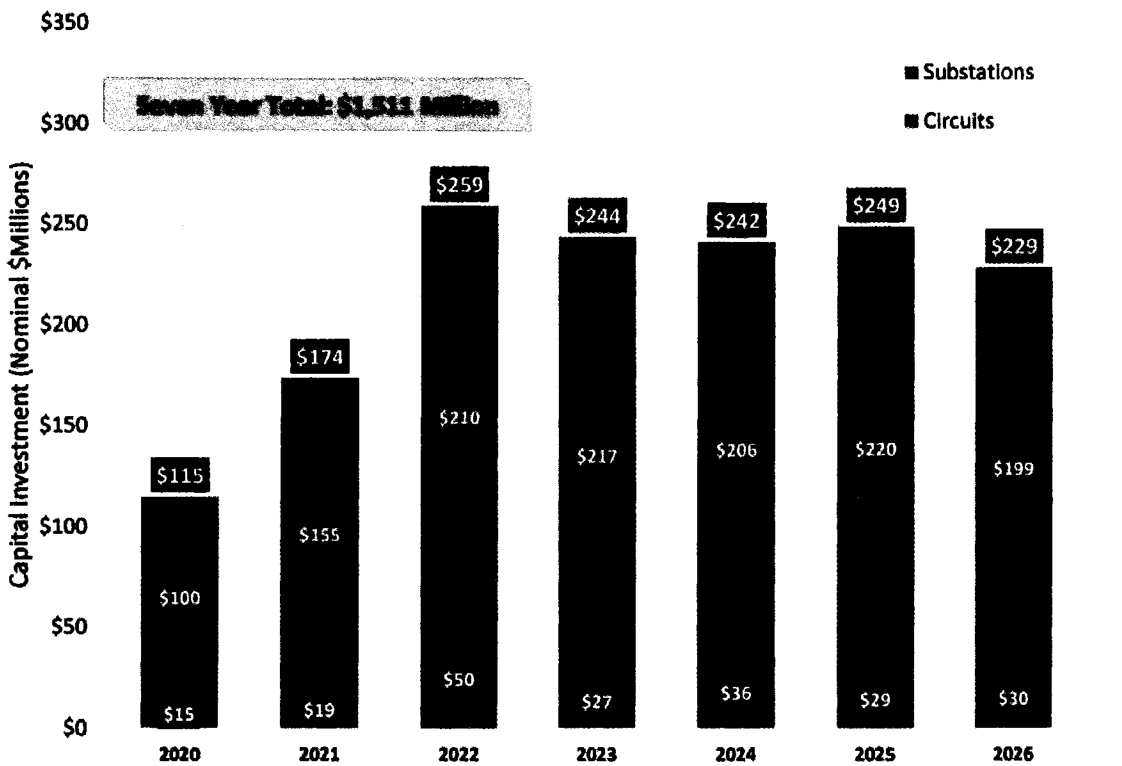
5.4 LOF 4 Scenario Results

This section shows the investment plan, risk heat maps after investment, and business case summary results for the LOF 4 Scenario. The approach to selecting the assets and prioritizing for replacement is outlined in Section 5.2.3. At a high level, the LOF 4 plan replaces all assets with a LOF of 60 percent and greater.

5.4.1 LOF 4 Scenario Investment Plan Results

Figure 5-11 displays the annual capital investment profile of the LOF 4 Scenario totaling $1,511 million. The numbers in the chart include investment for the 4 kV conversion, unjacketed replacement plan, breaker remote end and relay project, and the asset replacements identified by the Asset Risk Model. Substation total spend is approximately $206 million, while total spend for circuits is approximately $1,306 million. In total, there are 488 substation asset replacements or retirements and 3,136 section miles of circuits replaced or retired. Based on IPL's and external contractor's execution capacity, the plan is likely executable on the substation side, however the circuit plan is likely not executable.

Figure 5-11: LOF 4 Scenario Investment Profile



5.4.2 LOF 4 Scenario Risk Results Summary

Section 4.3 includes the heat maps for the substation asset and circuit counts and risk scores for the 'Do Nothing' scenario. The following two figures, Figure 5-12 and Figure 5-13, show the heat maps in 2026 after investment for substations and circuits respectively. The total asset and circuit counts in the figures differs from those in Section 4.3 because of the 4 kV conversion asset retirements. With the significant higher asset replacement levels, especially for the circuit assets, the total risk reduction is significantly more than the IPL TDSIC Risk-Based Scenario. The total risk of the substation asset base after investment is approximately 214,000 and approximately 2,159,000 for the circuit asset base for a combined system risk of 1,473,000 post investment. This is a decrease in risk compared to the 2026 'Do Nothing' scenario of 48.1 percent and 69.0 percent for substations and circuit, respectively, and 67.1 percent overall.

Figure 5-12: 2026 Substation LOF 4 Scenario Asset Count

Likelihood of Failure	2026 Investment Plan Risk Profile Asset Count					Total
Very High - 5	0	0	0	[illegible]	[illegible]	0
High - 4	[illegible]	0	0	0	[illegible]	0
Moderate - 3	[illegible]	[illegible]	3	203	267	479
Low - 2	[illegible]	[illegible]	[illegible]	119	153	283
Remote - 1	[illegible]	[illegible]	[illegible]	299	447	759
Total	1	17	15	621	867	[illegible]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure					

0 assets, or 0%, in High-Risk Region.

Figure 5-13: 2026 Circuit LOF 4 Scenario Circuit Count

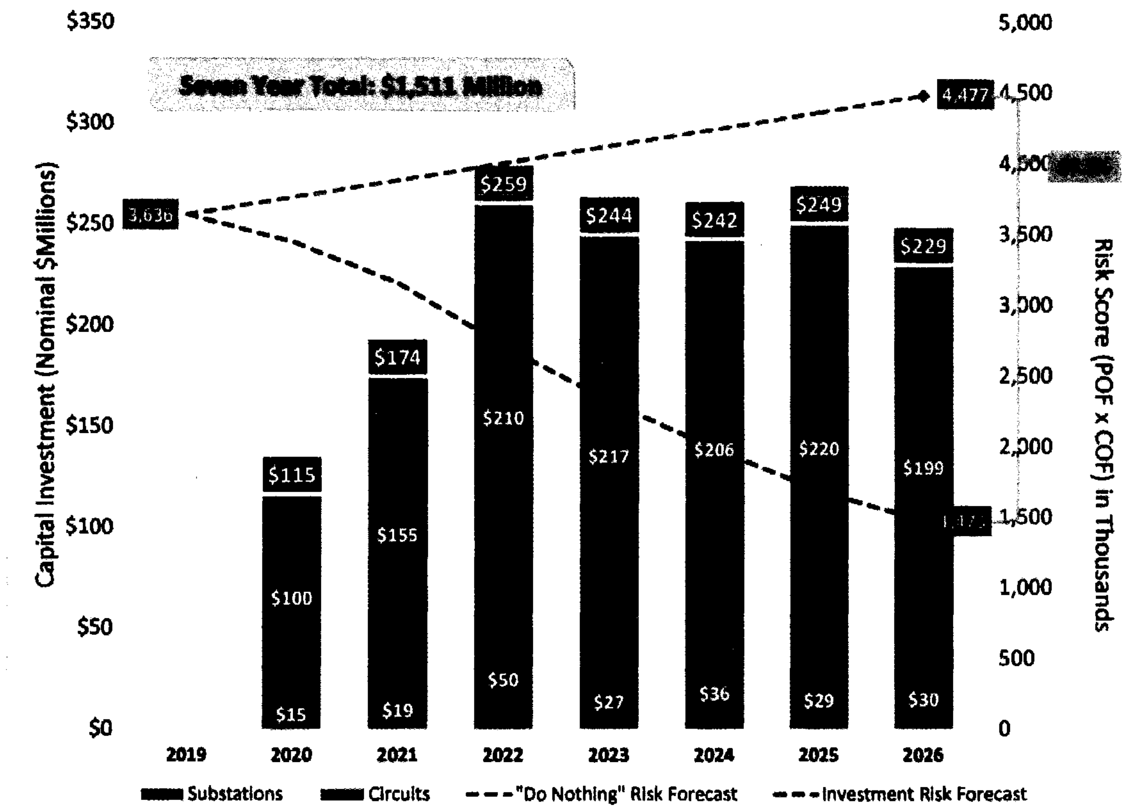
Likelihood of Failure	2026 Investment Plan Risk Profile Circuit Count					Total
Very High - 5	0	0	0	[illegible]	[illegible]	0
High - 4	[illegible]	0	0	0	[illegible]	0
Moderate - 3	[illegible]	[illegible]	3	0	36	39
Low - 2	[illegible]	[illegible]	[illegible]	16	179	198
Remote - 1	[illegible]	[illegible]	[illegible]	9	330	345
Total	0	5	7	25	545	[illegible]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure per Mile					

0 circuits, or 0%, in High-Risk Region.

5.4.3 LOF 4 Scenario Business Case Summary Results

Figure 5-14 shows the overall business case comparing risk reduction to invested capital for the LOF 4 Scenario.

Figure 5-14: LOF 4 Scenario Capital Investment vs. Risk Profile



The following highlights some of the main business case points for the LOF 4 Scenario:

- Total risk reduction by the end of 2026 (year 7) of 67.1 percent.
- Replacement or retirement of 488 substation assets (approximately $206 million) and 3,136 section miles of circuits (approximately $1,306 million) for a total investment in capital of approximately $1,516 million.
- No assets remaining in the High-Risk Region.
- Risk points reduced per million dollars invested of 1,988.

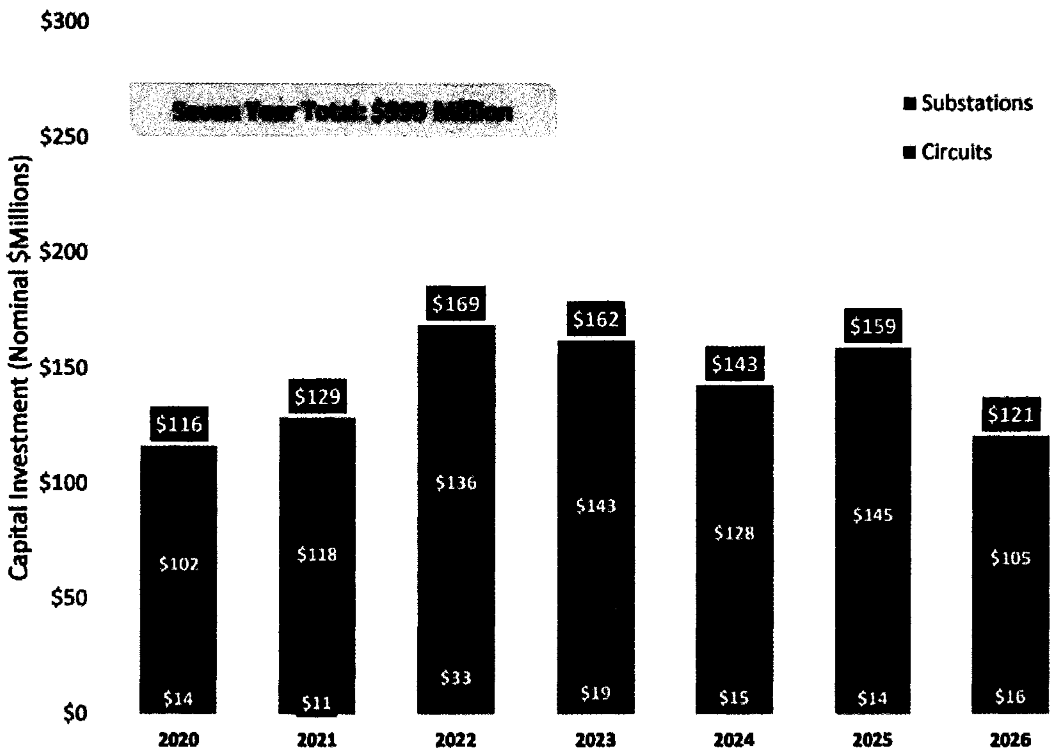
5.5 LOF 5 Scenario Results

This section shows the investment plan, risk heat maps after investment, and business case summary results for the LOF 5 Scenario. The approach to selecting the assets and prioritizing for replacement is outlined in Section 5.2.4 above. At a high level, the LOF 5 Scenario replaces all assets with a LOF of 80 percent and greater.

5.5.1 LOF 5 Scenario Investment Plan Results

Figure 5-15 displays the annual capital investment profile of the LOF 5 Scenario totaling $999 million. The numbers in the chart include investment for the 4 kV conversion, unjacketed replacement plan, breaker remote end and relay project, and the asset replacements identified by the Asset Risk Model. Substation total spend is approximately $122 million while circuit total spend is approximately $877 million. In total, there are 328 substation asset replacements or retirements and 2,332 section miles of circuits replaced or retired. While the plan is executable on the substation side, the circuit plan is likely not executable.

Figure 5-15: LOF 5 Scenario Investment Profile



5.5.2 LOF 5 Scenario Risk Results Summary

Section 4.3 includes the heat maps for the substation asset and circuit counts and risk scores for the 'Do Nothing' scenario. The following two figures, Figure 5-16 and Figure 5-17, show the heat maps in 2026 after investment for substations and circuits respectively. The total asset and circuit counts in the figures differs from those in Section 4.3 because of the 4 kV conversion asset retirements. With the significant higher number of asset replacements, the total risk reduction is significantly more than the IPL TDSIC

Risk-Based Scenario. The total risk of substation asset base after investment is approximately 265,000 and approximately 2,137,000 for the circuit asset base for a combined system risk of 2,402,000 post investment. This is a decrease in risk compared to the 2026 'Do Nothing' scenario of 35.6 percent and 47.4 percent for substations and circuit, respectively, and 46.4 percent overall.

Figure 5-16: 2026 Substation LOF 5 Scenario Asset Count

Likelihood of Failure	2026 Investment Plan Risk Profile Asset Count					Total
Very High - 5	0	0	0	[illegible]	[illegible]	0
High - 4	[illegible]	0	1	57	[illegible]	160
Moderate - 3	[illegible]	[illegible]	3	203	267	479
Low - 2	[illegible]	[illegible]	2	119	157	286
Remote - 1	[illegible]	[illegible]	[illegible]	241	342	596
Total	1	17	15	620	868	[illegible]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure					

159 assets, or 10%, in High-Risk Region.

Figure 5-17: 2026 Circuit LOF 5 Scenario Miles Count

Likelihood of Failure	2026 Investment Plan Risk Profile Circuit Count					Total
Very High - 5	0	0	0	[illegible]	[illegible]	0
High - 4	[illegible]	0	0	0	[illegible]	5
Moderate - 3	[illegible]	[illegible]	3	0	77	80
Low - 2	[illegible]	[illegible]	3	18	418	440
Remote - 1	[illegible]	[illegible]	[illegible]	3	49	57
Total	0	5	7	21	549	[illegible]
	Very Low - 1	Low - 2	Moderate - 3	High - 4	Very High - 5	
	Consequence of Failure per Mile					

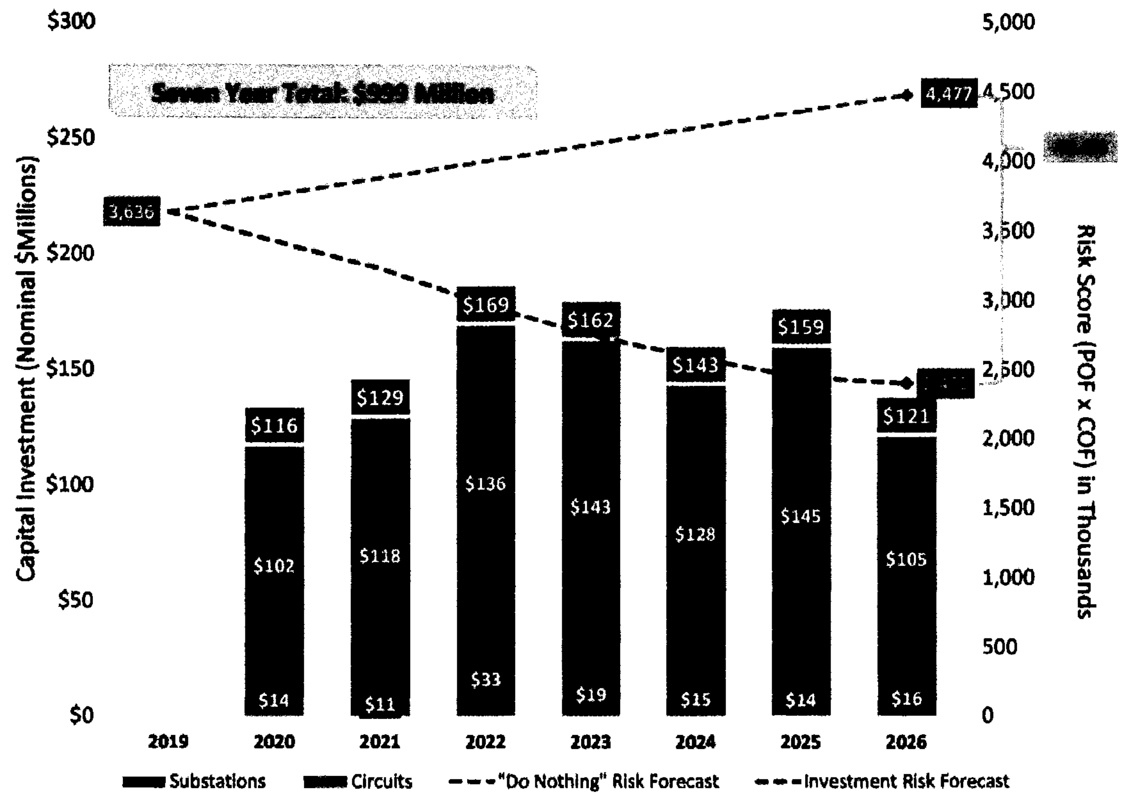
5 circuits, or 1%, in High-Risk Region.

For the substation asset base, before investment, the High-Risk Region included 411 assets (Figure 4-4) with a total risk score of approximately 212,000. After the LOF 5 Scenario, 159 assets remain in the High-Risk Region. Those 159 assets have a risk score of approximately 57,000. The Risk-Based Scenario replaces all substation assets in the High-Risk Region. Figure 5-17 shows that the LOF 5 Scenario removes most of the circuits from the High-Risk Region.

5.5.3 LOF 5 Scenario Business Case Summary Results

Figure 5-18 shows the overall business case comparing risk reduction to invested capital for the LOF 5 Scenario.

Figure 5-18: LOF 5 Investment Plan Capital Investment vs. Risk Profile



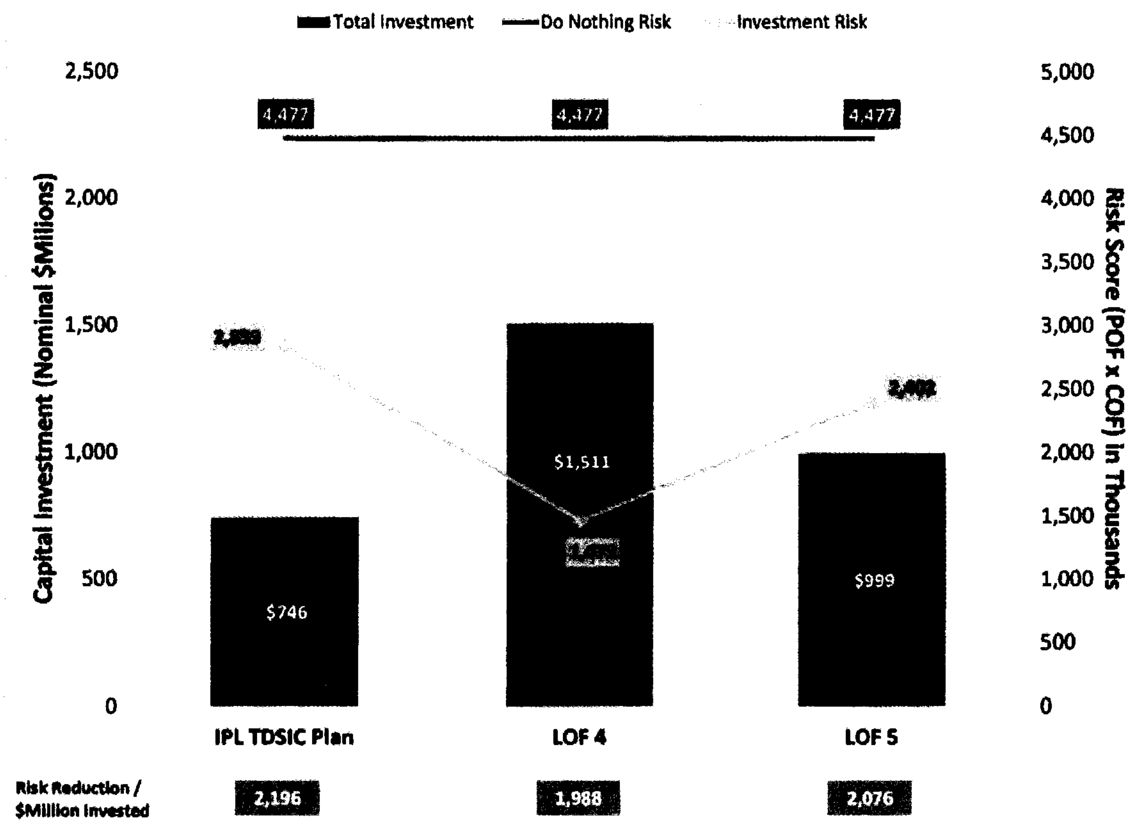
The following highlight some of the main business case points for the LOF 5 Scenario:

- Total risk reduction by the end of 2026 (year 7) of 46.4 percent.
- Replacement or retirement of 328 substation assets (approximately $122 million) and 2,332 section miles of circuits (approximately $877 million) for a total investment in capital of approximately $999 million.
- 159 substation assets and 5 circuits remain in the High-Risk Region.
- Risk reduced per million dollars invested of 2,076.

5.6 Investment Scenarios Summary Results

Figure 5-19 summarizes the three investment plan business cases. The figure is a summary and comparison of the results shown above in Sections 5.3, 5.4, and 5.5. The red line represents the 'Do Nothing' risk results while the green line represents the 2026 risk score of each scenario investment plan. The blue bars show the total 7-year investment for each scenario. The orange box shows the risk reduction per million dollars invested, a measure of the investment scenarios capital efficiency.

Figure 5-19: Scenario Risk and Investment Summary Results



The figure and sections above show the following:

- The age-based investment scenarios LOF 4 and LOF 5 require more capital investment than the IPL TDSIC Plan scenario, $765 million and $253 million more for LOF 4 and LOF 5 scenarios, respectively.
- The IPL TDSIC Plan has the highest risk reduction efficiency of 2,196
- The IPL TDSIC Plan scenario replaces all the substation assets in the High-Risk Region. While the IPL TDSIC Plan does not remove all the circuits from the High-Risk Region, this is due to

technical execution constraints. The LOF 4 plan removes all the substation assets from the High-Risk Region while the LOF 5 plan still has 159 assets. The LOF 4 and LOF 5 scenarios remove all or nearly all the circuits from the High-Risk Region.

- The IPL TDSIC Plan incorporates the other factors and constraints identified in Section 5-2 (e.g. project coordination, MISO outages, contractor limits) to execute investments over the 7-year period.
- While the LOF 4 and LOF 5 scenarios have more risk reduction than the IPL TDSIC Plan scenario, they come at a significantly higher cost and lower risk reduction per dollar invested. The LOF 4 and LOF 5 scenario capital efficiencies (1,988 and 2,076, respectively) are less than that of the IPL TDSIC Plan (2,196).

As discussed throughout the report, IPL utilized a risk-based planning approach in creating a 7-year TDSIC capital plan with the goal of managing high-risk assets and providing economic risk reduction. The IPL TDSIC plan manages the risk with all the assets in the High-Risk Region up to IPL's technical executable constraints, while achieving the highest capital efficiency and spending less than the LOF 4 and LOF 5 scenarios.

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Appendix 8.4 Black & Veatch Review of the Burns & McDonnell Risk Model

BLACK & VEATCH REVIEW OF THE BURNS & MCDONNELL RISK MODEL

B&V PROJECT NO.400364

PREPARED FOR

Indianapolis Power & Light Company (IPL)

JULY 2019

BLACK & VEATCH

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1.0 Overview

During Q4 2018 Black & Veatch was commissioned by Indianapolis Power & Light ("IPL") to conduct an inspection and review of the IPL Transmission and Distribution System Asset Risk Model ("Risk Model") that was developed by Burns & McDonnell ("BMcD"). This model is a MS Excel-based planning and diagnostic tool. IPL uses the Risk Model to parameterize, gauge and measure certain risk attributes related to the IPL Transmission and Distribution ("T&D") system. This model is the joint property of BMcD and IPL. IPL commissioned BMcD to assemble IPL transmission and distribution system asset data, inspect and format the data and apply it to the Risk Model. BMcD and IPL developed input assumptions required by the model that relate to asset failure impacts and other various parameters characterizing the likelihood of asset failures.

The purpose of this memorandum is to explain Black & Veatch's review of the Risk Model and provide Black & Veatch's observations about it. IPL requested that Black & Veatch inspect and review the Risk Model for general soundness in relation to certain practice norms, inspect the inputs that have been used, and to validate that the model yields reasonable outputs given the nature of the applied inputs.[1]

2.0 Qualifications

IPL selected Black & Veatch to perform this review because of Black & Veatch's independence in this matter and its asset management consulting practice qualifications and capabilities in general. Black & Veatch also has specific experience related to the Indiana Transmission, Distribution and Storage System Improvement Charge ("TDSIC") plan development process and evaluation norms associated with it.

Specifically, Black & Veatch uses and deploys similar asset registry and risk models in its work with electric and gas utilities for similar risk attribute assessments that were conducted for IPL by BMcD. Black & Veatch is highly familiar with the use, construction and operation of asset registries and risk models. Black & Veatch's consultants are also leaders in applying industry practice norms related to asset management assessments. These involve application of the International Organization for Standardization ("ISO") standards and guidelines to gather and apply asset performance data and to measure and quantify risk in relation to and arising from this data.[2] This expertise in applying essential asset management practice norms greatly influence the nature of the review.

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[1] IPL requested that Black & Veatch and BMcD work collaboratively to conduct this inspection and review of the Risk Model. In fact, the success of this effort was only possible through the collaboration of BMcD, IPL and Black & Veatch in this matter.

[2] Black & Veatch's extensive experience includes asset management planning, capital prioritization, asset failure analysis, risk assessment using the International Organization for Standardization standard for risk management (ISO31000), performance benchmarking, maintenance optimization, business planning, serviceability assessment, whole life costing, operational efficiency, International Organization for Standardization standard for asset management maturity assessments (ISO55001), business change management, and infrastructure rehabilitation.

3.0 Scope Definition and Purposes

To conduct this Risk Model inspection and review, Black & Veatch carried out the following activities. The purposes of each activity is also described.

Black & Veatch:

1) Inspected the MS Excel-based computer spreadsheet Risk Model's "architecture". This means the structure of the spreadsheet model and how parts of the model interact to translate inputs to outputs.

2) Inspected certain formulas used in the Risk Model through in person and web-based meetings. The inspections were limited to formulas that BMcD considered non-proprietary. Also, this step was conducted on a sampling basis. For those formulas that were considered proprietary, Black & Veatch and BMcD discussed their purposes and principles for 'reasonableness'.

3) Inspected some data sets that were provided by IPL and then applied within the Risk Model. This too was conducted on a sampling basis.

4) Reviewed a set of Risk Model input assumptions, including unit cost data, asset depreciation curves from IPL's most recent depreciation study, and criticality criteria from IPL's Asset Management system. This step was conducted on a sampling basis as well. However, the most impactful assumptions (in Black & Veatch's judgment) were included in this review.

5) Inspected the assumptions that BMcD applied to the Risk Model that involve broad adjustments to classes of data and/or other input assumptions. This constitutes both informal or formal "rules" by the model analyst that ostensibly could play a role in influencing the input data (and therefore final model evaluation outputs, and potentially conclusions). This step includes the method used to adjust the actual asset ages to determine effective ages, and 'scoring approaches' for assessing the risk of asset classes.

6) Inspected the Risk Model results (i.e., outputs) in the form of tabular data and graphs.

The intention of the work was not to conduct a detailed audit of the Risk Model. In fact, in performing this work Black & Veatch inspected the model, formulas, input assumptions, and data sets, informal sampling techniques, and informal questioning of BMcD model users.

IPL commissioned Black & Veatch to provide a check on the **soundness** of the model (architecture, methods, data inputs, computations, outputs) in relation to asset practice norms , and to identify and describe for reasonableness unexpected or uncommon elements of the Risk Model in relation to generating outputs (which in turn support the rendering of conclusions) regarding the risk attributes of the IPL T&D system assets. The six (6) activities identified above represent means towards these ends and are described further in Table 3-1.

Table 3-1 B&V Review and Inspection Scope

WORK AREA	OBJECTIVE	SCOPE	LIMITATIONS
Inspected Risk Model "architecture"	Model architecture inspected for conformance with Asset Management norms (per practice norms in Indiana and elsewhere and ISO 31000 and 55000 standards)	B&V model inspection of model architecture and core modules and essential functionality	Formulas and model logic deemed as proprietary were verbally discussed only with BMcD.
Inspected formulas	Inspected model formulas in meetings and spot checked (sampled) the use of depreciation curves for breakers	Spot check of some formulas through re-creating the development of likelihood of failure calculations for breakers	Proprietary model was not provided to Black & Veatch so spot check was done by re-creating likelihood of failure calculations for breakers
Inspected data sets	Inspected data IPL provided to BMcD for completeness and to understand how BMcD modified source data[3] for the Risk Model	This included unit cost data, asset depreciation curves from IPL's most recent depreciation study, condition data and scoring, and criticality criteria from IPL's Asset Management system.	
Reviewed input assumptions	Inspected input assumptions through face to face and web meetings	This included: • unit cost data • asset depreciation curves from IPL's most recent depreciation study • criticality criteria from IPL's Asset Management system	Since the proprietary model was not provided to Black & Veatch, the model was inspected through face to face and web meetings
Inspected "rules" that influence model	Inspected model rules through face to face and web meetings	This included: • infilling of missing age data • effective age adjustments • consequence of failure scoring rules	Since the proprietary model was not provided to Black & Veatch, the model was inspected through face to face and web meetings
Inspected Risk Model Results	Inspected model outputs through face to face and web meetings	Reviewed Risk Model output for reasonableness	Since the proprietary model was not provided to Black & Veatch, the model was inspected through face to face and web meetings

[3] Data is often modified to address errors and gaps in the data and to format it and otherwise prepare it for use in the model. Often poor data is eliminated for further use. Sometimes modelers use the phrase "scrub the data" to describe these steps. Scrubbing the data improves the model's quality by improving the integrity of the data that is eventually applied within the model.

4.0 Black & Veatch Review Method

To perform this work Black & Veatch conducted several meetings with BMcD and IPL so the BMcD team members could explain to Black & Veatch how the Risk Model was developed, how the input assumptions were derived, how missing input data was infilled,[4] how model formulas operate, and how results were generated and interpreted.

Because of the proprietary nature of the Risk Model, Black & Veatch was not provided a copy of the Risk Model for independent audit and review. Rather, during the meetings BMcD demonstrated and discussed the model in a logical step-wise fashion. Separate and apart from these meetings Black & Veatch re-created the BMcD model likelihood of failure calculation for transmission system breakers and compared these results to a summary table from the BMcD model. Transmission system breakers were selected for this step because they are a large and important asset class. Black & Veatch also reviewed BMcD-created documentation explaining the Risk Model architecture, inputs and outputs.

Additionally, as part of the inspection and review of the Risk Model attributes (inputs, outputs, and computational 'engine'), Black & Veatch levered its experience with similar risk modeling exercises. Using public domain information, specific areas of review include:

- ISO-based Risk Framework (meaning the way in which risk is measured and assets compared)
- Average service life data by asset class
- Depreciation curves by asset class
- Model Output

5.0 Risk Model Description

The goal of using the Risk Model is to determine a way to focus on high-risk assets for priority replacement. This is done by quantifying the risk reduction achieved by investing in the replacement of certain assets whose risk score is in the higher risk regions of the heat map. The quantification is the product of the consequence of an asset's failure and its likelihood of failure. The assets with a higher consequence and likelihood of failure pose a higher risk to IPL's T&D system. Once the Risk Model was developed, it was then used by BMcD to help IPL identify the capital expenditures for substations and circuits that were part of IPL's TDSIC filing. IPL used their engineering judgement to determine the amount of work that was able to be completed in a seven-year period and then the Risk Model identified the assets for replacement.

[4] This activity is common when working with large data sets. The primary method for infilling was using the install year from other assets that were in close proximity. An example is using the install year of a pole for conductor.

6.0 Black & Veatch Inspection and Review of Risk Model Architecture

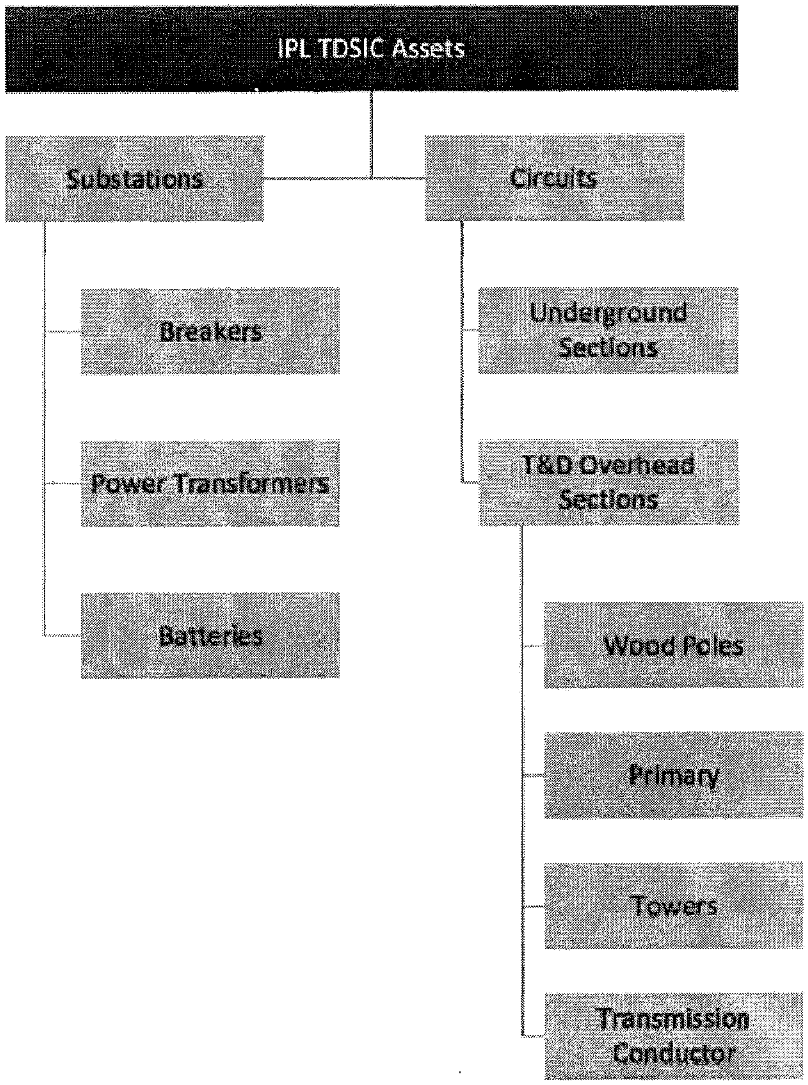
Black & Veatch used its knowledge of Asset Management norms (practice norms in Indiana and elsewhere and ISO 55000 standards) to inspect the Risk Model architecture. This was completed through face to face and web meetings as noted earlier. BMcD broadcasted the MS Excel model to the meeting participants, reviewing and explaining the model architecture. The modules depicted in Figure 6-1 were included in this review. The exception was the Geodatabase which was explained as propriety to BMcD. However, BMcD and its Geodatabase expert explained the way in which the database was developed and how and where the source data was acquired.

During these meetings Black & Veatch requested deeper explanations when the architecture deviated from other models about which Black & Veatch is aware (and in some cases expert users of). Black & Veatch separately conferred to discuss the differences and determine if the differences were significant enough to cause model result deviations (from what other models might generate).

Another important attribute of the Risk Model architecture is the manner in which assets relate to each other in a hierarchical way. The asset hierarchy is used in the asset register to aggregate risk up from the asset class level to the substation/circuit levels and to display outputs and results at the substation/circuit levels. Figure 6-2 shows the asset hierarchy for the Risk Model that was provided by BMcD.

The asset hierarchy described within the Risk Model are used to identify the capital expenditures for substations and circuits; not all of IPL's asset classes and assets, however, are evaluated within the Risk Model. Some examples of asset classes *not* included in the Risk Model include: the Central Business District assets, communication system assets, protection devices, relays, and switches.

Figure 6-1 Risk Model Asset Hierarchy



Black & Veatch offers the following observations regarding its inspection of the Risk Model architecture:

- The Risk Model's architecture aligns with risk models that Black & Veatch has developed for other utilities evaluating asset replacements.
- The Risk Model asset hierarchy also aligns with risk models that Black & Veatch is familiar with.
- By *alignment*, Black & Veatch means:
  - The model structure – down to the modules themselves -- is very similar to that which Black & Veatch is familiar, and which it applies in other jurisdictions.
  - The modules interact and relate in ways required to determine the necessary model evaluation outputs, namely: heat maps and summary graphs showing risk reduction, expenditures and

the ratios of these. Black & Veatch found no gaps that would imply the inability to generate the intended computational outputs.

- The asset classes selected for the model are the same as those included in the risk models presented by Black & Veatch in other TDSIC filings. For circuits the risk is aggregated from the section (i.e. pole/tower and conductor) level to a circuit level in order to understand the impact circuits have on the system. However, the Risk Model pinpoints risk of specific sections to prioritize replacement within the circuits.

In brief, Black & Veatch found no weaknesses or gaps in the Risk Model from an architecture design standpoint. It is built in a way that an asset manager proficient in ISO 55000 and ISO 31000 practice norms would find logical, reasonable, sufficient, and required.

7.0 Inspection and Review of the Risk Model Formulas

Black & Veatch used the Risk Model architecture as a guide to review the Risk Model formulas. Due to the proprietary nature of the Risk Model, Black & Veatch's formula inspection was performed as BMcD demonstrated and discussed the model with Black & Veatch, explaining the major parts of the Risk Model. This occurred as part of several in person and web-based meetings.

Similar to the architecture review, Black & Veatch inquired about formulas in an organized and systematical way to learn more about the formulas and trace how they were operating within the model. Black & Veatch used these occasions to inquire deeply about how the model formulae were constructed, and why certain methods were applied. As with the architecture review, Black & Veatch levered its own expertise in developing and operating similar models. When there were differences in approaches, the BMcD and Black & Veatch participants talked freely about what was behind these choices in approach. Throughout, Black & Veatch was mindful about inquiring about formulas and deliberately focused on the ones that had the greatest influence on model results.

Black & Veatch offers the following observations regarding its inspection of the Risk Model formulas:

- The Risk Model formulas align with other risk models that Black & Veatch has developed for other Indiana TDSIC filings and other places.
- By alignment in this context, Black & Veatch means:
  - The formulas appear logical and well structured,
  - They appear to perform the necessary computations correctly,
  - The layout allows for copying and pasting formulas to prevent formula errors,
  - Formulas are linked to key settings so that when the settings are updated the changes flows to all applicable formulas.

8.0 Inspection and Review of the Risk Model Data Sets (Inputs)

As part of IPL's ongoing asset management efforts, IPL was able to assemble a large quantity of data for potential use within the Risk Model. First, IPL focused on data that it knew would be structured and evaluated within the Risk Model. (As noted earlier, some asset classes were excluded). Next, IPL provided data that resides in its Geographic Information System ("GIS"), Osmose, and Excel spreadsheets. Black & Veatch reviewed the asset data provided to BMcD to gain a familiarity with it. As part of in person and web-based sessions BMcD explained to Black & Veatch how the data was set up with the model and how the various modules and formulas operated in it. During these sessions Black & Veatch asked many questions to gain an understanding about the way BMcD applied the data in the Risk Model.

In addition to the review, Black & Veatch used some of the IPL data (specific to the Risk Model) to do a spot check.

The principal or main types of data provided to BMcD were as follows:

- Asset Record Information
  - Unique Identifiers used for asset identification
  - Asset Description
  - Install Year
  - Location
  - Other key information needed for the asset register
- Depreciation Studies
- Asset Health Information (e.g. condition assessment scores and framework and IPL Asset Management documentation)
- IPL's Existing Consequence Framework
- IPL's Asset Hierarchy
- Geodatabase Query

Black & Veatch offers the following observations regarding its inspection of the Risk Model Data Sets:

- IPL has more asset health information and scoring guidelines available than other utilities for which Black & Veatch has developed risk models. This information provides a better understanding of the actual health of the assets to determine the effective age instead of only relying on chronological age. The overall impact of the data was to decrease the average age of those assets and provide more validation that the model likelihood of failure was not overstated.
- The install year was not available for every asset in each asset class so BMcD used age infilling to determine the install year. The methods used for infilling age were appropriate to use when developing risk models.

9.0 Inspection and Review of the Risk Model Input Assumptions

Black & Veatch distinguishes here between the *data sets* (above) and other forms of input *assumptions*. The data sets are of course inputs. In this section, however, Black & Veatch focuses on model assumptions that operate on many of the data sets.

In a way comparable to the review of the architecture, Black & Veatch completed a sample-oriented inspection and review of the Risk Model input assumptions as part of in person and web-based meetings. BMcD, as before, broadcasted the Risk Model. Black & Veatch used these sessions to inquire about the input assumptions as they were encountered. Later, Black & Veatch met as a team to discuss the input assumptions, differences from Black & Veatch's experience in applying similar factors to its asset risk models. The focus of course was on assumptions of significant importance to the Risk Model results.

The main assumptions that Black & Veatch reviewed are as follows:

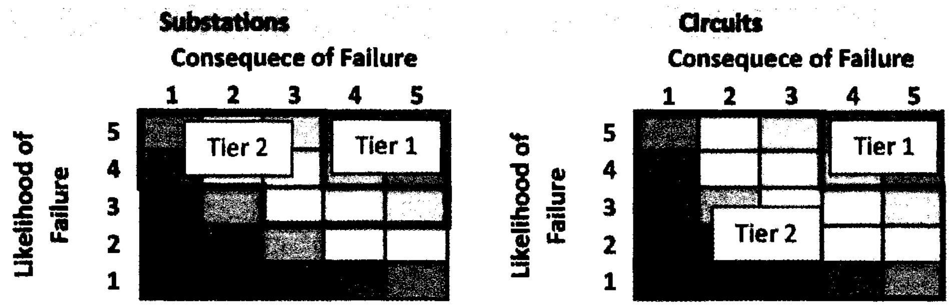
- Unit Cost Data
- Inflation Factor
- Asset Depreciation Curves
- Average Service Lives
- Criticality Criteria
- Red Zone Selection
- IPL Resource Constraints

Black & Veatch offers the following observations regarding its inspection of the Risk Model Input Assumptions:

- Unit Cost Data – Black & Veatch reviewed the unit cost data that IPL provided to BMcD for the Risk Model and Black & Veatch was comfortable with the Association for the Advancement of Cost Engineering ("AACE") class estimates.
- Use of Asset Depreciation Curves – Black & Veatch compared BMcD's selection of each asset class depreciation curve with other utilities. Though differences are observed, the selection methods and curve usage aligned with the other utilities. By alignment in this context, Black & Veatch means the shape of the curves were the same or similar.
- Average Service Lives – Overall IPL has longer average service lives than the other utilities that Black & Veatch compared. This appears to be the result of the efforts IPL has undertaken around asset management. This means that when the model identifies assets for replacement, they are already older than other utilities.
- Criticality Criteria – BMcD's method uses a wide range of scores to weight the impact of consequence of failure while some other models used and reviewed by Black & Veatch applied a multiplier to weight the score. Though the methods are slightly different, both work well to state the consequence of failure for each asset class to understand the overall system risk. In addition to reviewing the criteria, Black & Veatch worked with BMcD and IPL to calibrate the consequence of failure definitions and related score. The resulting consequence of failure details can be found in the BMcD Risk Model Report. To further explain, BMcD chose to score consequence of failure with a graduated scale with up to 16 different consequence levels that ranged from a score of 0 to 1,000. The appropriate score was developed and applied to the different asset classes. There were six different failure (i.e., consequence) categories (e.g. Safety Impact, Customer Impact, Environmental Impact, Restoration, System Operation/Production, and Regulatory/Public). The categories have multiple criteria within them and the Risk Model uses the max score within each.
- Red Zone Selection – The Red Zone is used as a guide when developing the TDSIC plan for substations and circuits. In this Risk Model, the Red Zone represents tier one assets. This includes

assets that have a consequence of failure ("COF") of greater than, or equal to 4 and an LOF of greater than, or equal to 4. Assets in this region were targeted for replacement first within the seven-year period. The Red Zone approach used in the Risk Model covers less of the risk grid than other risk models Black & Veatch has worked with; however, it still is appropriate for the Risk Model as it uses the tier one assets to identify highest risk assets for replacement and then relies on tier two to focus investment based on risk reduction per dollar spent.

Figure 9-1 Red Zone Target Region – IPL



- IPL Resource Constraints – BMcD designed the Risk Model to handle resource constraints and then worked with IPL to calibrate the limits for each asset class. An example of this is restricting the Risk Model with the number of circuits that are able to be replaced in a given year based on resources and system availability. This approach aligns with the way Black & Veatch constrained the risk models it presented in other Indiana cases. By alignment in this context, Black & Veatch means that the other models had the ability to also limit the number of assets class replacements per year.

10.0 Inspection and Review of the Model's General Rules

The Risk Model has a wide range of broad or general rules used to apply the various input assumptions to each asset in the Risk Model. This allows for the user to adjust information to the thousands of asset records and allows for the model to be updated annually.

As with the review of the architecture (in person, etc.) Black & Veatch reviewed the Risk Model general rules with BMcD. Similar to the architecture review, Black & Veatch reviewed general rules and requested additional explanations when unfamiliar rules were found (per Black & Veatch's experience). Black & Veatch met as a team to discuss the differences, determining their importance and impact.

The main types of general rules that Black & Veatch reviewed are as follows:

- Infilling of Missing Install Years
- Effective Age Adjustments
- Consequence of Failure Scoring Rules

Black & Veatch offers the following observations regarding its inspection of the Risk Model Data Sets:

- Infilling of Missing Install Years – The availability of asset's install year is a common issue that utilities are faced with when developing a risk model. IPL was not unique with the data that was available for determining the age of their assets.

There was sufficient substation asset data to determine an install year for breakers and power transformer assets.

- The install year for batteries, breakers, and power transformers were not in the system so an IPL subject matter expert ("SME") reviewed physical records to determine the install year.
- For the circuit assets, there were more data gaps with the install date for the conductor.
- There was good install year asset data for poles and towers so BMcD used the GIS information to match poles and towers with conductors to determine the install year.

- Effective Age Adjustments – The availability of condition test data allows for an asset's effective age to be determined by adjusting the chronological age to incorporate the health of the asset. IPL had good condition data available for breakers, power transformers, and poles. In addition to the data, IPL already had the data in a format that was easy to use along with testing thresholds that allowed BMcD to determine the asset health. These were the only assets in the Risk Model that had asset health data.
- Consequence of Failure Scoring Rules – The scoring rules allow for the Risk Model to assign a consequence of failure score to each of the asset records in the model. BMcD worked directly with IPL SMEs to understand the magnitude of failure for each of the asset classes in the Risk Model and then applied the rules. This is the same approach Black & Veatch has used to develop scoring rules in similar risk models.

11.0 Inspection and Review of Model Results

Black & Veatch discussed the Risk Model results when BMcD was finalizing the circuits and substations that would be included in the TDSIC filing. IPL, BMcD, and Black & Veatch had numerous web meetings where BMcD would show the Risk Model outputs and explain the way the scenario was developed along with the drivers that caused the Risk Model to select the various circuits and substations for replacement. As with the architecture review, Black & Veatch levered its own expertise in developing and operating similar models. When there were differences in the results, the BMcD and Black & Veatch participants talked freely about what was behind these results.

In addition to discussing the Risk Model results with BMcD, Black & Veatch also reviewed the results based on Black & Veatch's experience with similar risk modeling. A portion of the Risk Model was also recreated by Black & Veatch to check the application of likelihood of failure curves to one of the asset classes in the Risk Model.

Black & Veatch offers the following observations regarding its inspection of the Risk Model formulas:

- Risk Model Results Generation – The Risk Model provides results over a seven-year period and the risk reduction results aligns with the range of risk reduction in similar risk modeling conducted by Black & Veatch. By alignment in this context, Black & Veatch means the Risk Model shows a 36.6% reduction in risk as compared to the other modeling that ranges from 21% to 40% risk reduction. After reviewing the architecture, input data and assumptions, and other model attributes described in this memorandum, Black & Veatch found that the model performs the computations effectively.
- Risk Model Simulation – The Risk Model simulation performed by Black & Veatch resulted in the same likelihood of failure score as the one that was shown in the Risk Model that was developed by BMcD.

12.0 Conclusion

Black & Veatch undertook a thorough review of the Risk Model developed by BMcD in the manner described (in person meetings, web-based sessions, and recreation of certain functionality). The fundamental approach of taking IPL's data and developing asset registers that were then used to prioritize capital expenditures to target assets in the Red Zone is the same as that taken in similar Black & Veatch risk modeling. The Risk Model developed by BMcD has differences around the consequence framework, effective age adjustments, and the COF and LOF scoring of circuit segments. However, after reviewing the model, Black & Veatch feels confident that the Risk Model is appropriate to use to identify capital expenditures for substations and circuits that are part of IPL's TDSIC filing.

The Economic Impacts of IPL's Plan to Upgrade its Electric Transmission and Distribution System

July 2019

KELLEY SCHOOL OF BUSINESS
INDIANA UNIVERSITY
Indiana Business Research Center

Appendix 8.5 IBRC's Economic Impact Assessment Report

The Economic Impacts of IPL's Plan to Upgrade its Electric Transmission and Distribution System

July 2019

Prepared for
Indianapolis Power & Light Company

By
Indiana Business Research Center,
Kelley School of Business, Indiana University

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Executive Summary

Indianapolis Power & Light Company (IPL) has developed a Transmission Distribution Storage System Improvement Charge (TDSIC) Plan to invest approximately $1.2 billion over the next seven years to update and modernize the electric transmission and distribution (T&D) system in IPL's Central Indiana service territory. The broad range of activities IPL intends to undertake with this Plan are designed to better serve its customers by improving the reliability, efficiency and safety of IPL's system. While these are the core benefits of IPL's plan to improve and modernize its system, these investments will also provide secondary benefits for the area by generating additional economic activity.

In order to estimate these secondary economic benefits from this Plan, IPL partnered with the Indiana Business Research Center (IBRC) at Indiana University's Kelley School of Business to conduct an analysis of these activities and measure the economic ripple effects that this investment will generate both in Marion County and statewide.

The key findings from this analysis show that IPL's approximately $1.2 billion investment over this seven-year period will support an estimated 880 jobs annually in Marion County worth $62.2 million in compensation (i.e., pay and benefits) per year (see **Table 1**). In terms of the broader economy, IPL's activities will contribute an estimated average of $92.6 million to Marion County's gross domestic product (GDP) annually over the life of the Plan. This increased economic activity will also generate roughly $3.3 million per year in state and local government revenues.

Looking over the full span of the TDSIC Plan, IPL's investments will amount to more than $435 million in compensation in Marion County and nearly $648 million in GDP.

Table 1: Marion County—Average Annual Economic Contributions of IPL Capital Investments, 2020 to 2026

	Direct Effects	Ripple Effects	Total Effects	Multiplier
Employment	580	300	880	1.52
Compensation (millions, 2019 $)	$45.2	$17.0	$62.2	1.38
GDP (millions, 2019 $)	$63.4	$29.2	$92.6	1.46
State and Local Tax Revenue (millions, 2019 $)	—	—	$3.3	—

Source: IBRC, using data from IPL and the IMPLAN economic modeling software

When we broaden our focus to the state level, these average annual economic contributions rise to a total of 950 jobs, $66 million in compensation and nearly $99 million in GDP.

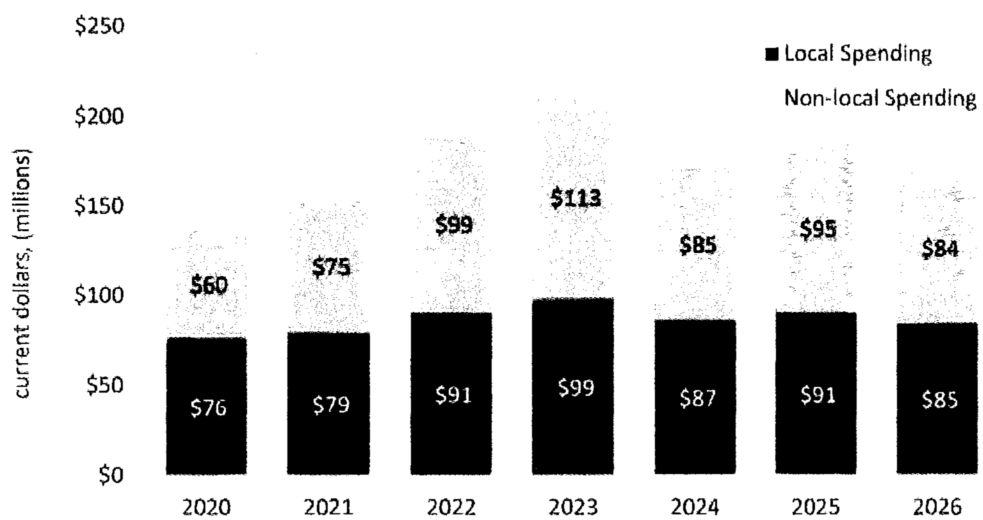
The report that follows will provide more detail on these findings, as well as outline the methodology used to produce these estimates.

Estimates of Economic Contributions

Figure 1 outlines IPL's expected spending over the next seven years to upgrade and modernize its electric T&D system in Central Indiana. IPL plans to invest an average of $174.1 million per year over this period, with peak spending in 2023 when expenditures will reach nearly $212 million. In all, IPL's TDSIC Plan calls for approximately $1.2 billion in capital investment over this span.

As with any production or construction activity, some portion of supply-chain spending will leak outside of the local economy (Marion County in this case) to manufacturers and service providers that are located elsewhere. Given that upgrading and modernizing an electric T&D system requires a good deal of highly specialized equipment and material, IPL estimates that slightly more than half of this spending—or $611.6 million over the seven-year period—will go to vendors outside the local area. Within the framework of economic impact analysis, this "non-local" spending is considered a leakage and does not factor into the economic contributions of IPL's investments discussed in this report.

Figure 1: IPL's Projected Annual Spending for Electric Transmission and Distribution System Upgrades



Source: IPL

In terms of local expenditures, IPL expects to spend an average of $86.7 million per year in Marion County over the life of this Plan. In the terminology of economic impact analysis, these local expenditures and the associated employment describe the "direct effects" of IPL's investments on the local economy. The benefits of these investments do not end there, however. The additional economic activity generated by these direct effects—the supply chain purchases from other businesses in the area along with the household spending of workers engaged in these T&D system improvements—cascade throughout the local economy.

In order to estimate these so-called economic "ripple effects," the IBRC used the IMPLAN economic modeling software to conduct an input-output analysis for IPL's TDSIC Plan. This widely used software relies on a variety of secondary data sources to build economic models that are tailored to reflect the unique industry mix of any given geographic area (the IBRC constructed separate models for Marion County and Indiana for this study). The ripple effect estimates derived from this analysis combine with the direct effects to describe the full economic contributions of IPL's investments.

Economic Effects of IPL's TDSIC Plan

As discussed earlier, IPL expects to spend an average of $174.1 million per year over the next seven years to upgrade and modernize its T&D system. The portion of this total that IPL expects to spend in Marion County will support an estimated 580 direct jobs per year in the area over the life of the project. These jobs will largely be concentrated in the construction and engineering fields. Along with these direct employment effects, this increased economic activity will support an additional 300 local ripple effect jobs per year resulting from supply chain purchases and the household spending associated with these direct jobs (see **Table 2**). This brings the full employment footprint of IPL's TDSIC Plan to an estimated 880 jobs per year between 2020 and 2026. This total employment impact will combine to produce an estimated $62.2 million in total compensation, which translates into nearly $70,700 in annual compensation per worker.

A helpful way to interpret these impacts is to look at the multipliers. The ratio of direct jobs to total jobs, for instance, gives a ratio of 1.52, meaning that every job directly tied to IPL's TDSIC Plan support another 0.52 jobs with other employers in the area (or every 10 direct jobs support slightly more than 5 additional jobs elsewhere). The compensation multiplier of 1.38 suggests that every dollar of direct payroll generates an additional $0.38 in compensation with other local employers.

In terms of total economic activity, the full impact of these IPL activities will combine to contribute an estimated $92.6 million per year to Marion County's gross domestic product (GDP) over the seven-year period. The multiplier of 1.46 indicates that every dollar of GDP directly generated by these investments will trigger an additional $0.46 in economic activity in the area.

IPL's TDSIC Plan to upgrade its T&D system will also generate state and local government revenues. The IMPLAN model estimates the tax revenues from business profits, indirect business taxes (e.g., sales, property and excise taxes), personal taxes (e.g., income and property taxes), and employer and employee contributions to social insurance. Fueled primarily by sales and property taxes, this investment in T&D system modernization will generate an estimated $3.3 million per year in state and local government revenue.

Table 2: Marion County—Average Annual Economic Contributions of IPL Capital Investments, 2020 to 2026

	Direct Effects	Ripple Effects	Total Effects	Multiplier
Employment	580	300	880	1.52
Compensation (millions, 2019 $)	$45.2	$17.0	$62.2	1.38
GDP (millions, 2019 $)	$63.4	$29.2	$92.6	1.46
State and Local Tax Revenue (millions, 2019 $)	—	—	$3.3	—

Source: IBRC, using data from IPL and the IMPLAN economic modeling software

As the supply chains that support IPL's investment activities extend to other parts of Indiana, the additional spending supports another 70 ripple effect jobs and the total employment impact of the TDSIC Plan expands from 880 jobs in Marion County to 950 jobs statewide (see **Table 3**). Furthermore, the average annual GDP impact of these investments will reach nearly $99 million at the state level.

Table 3: Indiana—Average Annual Economic Contributions of IPL Capital Investments, 2020 to 2026

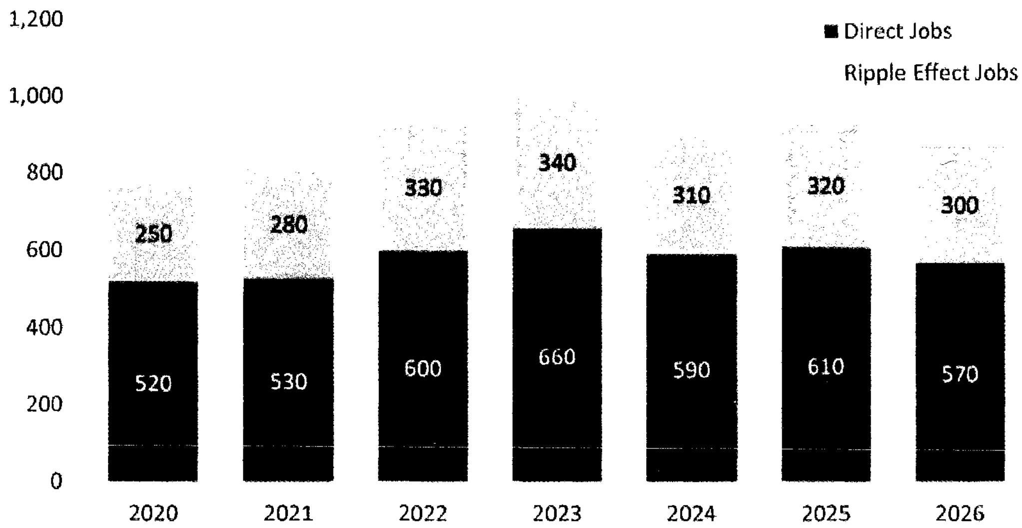
	Direct Effects	Ripple Effects	Total Effects	Multiplier
Employment	580	370	950	1.64
Compensation (millions, 2019 $)	$45.2	$20.7	$65.9	1.46
GDP (millions, 2019 $)	$63.4	$35.1	$98.5	1.55
State and Local Tax Revenue (millions, 2019 $)	—	—	$3.5	—

Source: IBRC, using data from IPL and the IMPLAN economic modeling software

Economic Impacts by Year

IPL's investments will ramp up from nearly $137 million in 2020 to a peak of roughly $212 million in 2023 before then subsiding a bit over the last three years of the Plan. The annual employment effects of this spending will follow a similar trajectory, with Marion County job totals reaching 1,000 by 2023 (see **Figure 2**). Over the seven-year period, the employment impacts of IPL's TDSIC Plan will never fall below an estimated 770 jobs in the county.

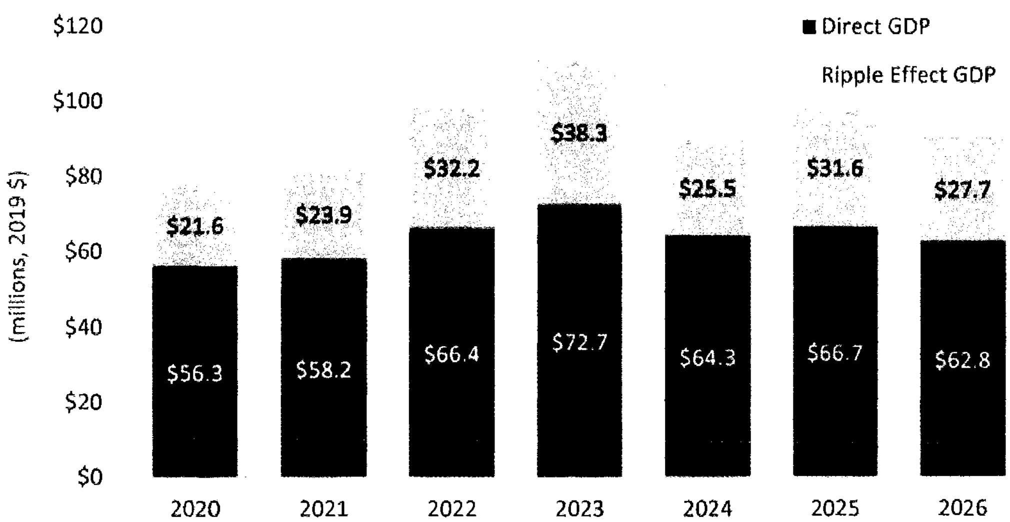
Figure 2: Marion County—Annual Employment Effects of IPL Capital Investments



Source: IBRC, using data from IPL and the IMPLAN economic modeling software

Annual contributions to Marion County's GDP will also top out in 2023, with total value added of approximately $111 million expected in that year (see **Figure 3**). In all other years, the GDP effects will range between nearly $80 million to roughly $99 million.

Figure 3: Marion County—Annual GDP Effects of IPL Capital Investments



Source: IBRC, using data from IPL and the IMPLAN economic modeling software

Appendix

Key Terms

Direct Effects: Refers to the increase in final demand or employment in a given area that can be attributed specifically to IPL's TDSIC Plan.

Ripple Effects: A combination of the indirect and induced effects generated by the direct effects. Indirect effects measure the change in dollars or employment caused when IPL increases its purchase of goods and services from suppliers and, in turn, those suppliers purchase more inputs and so on throughout the economy. Induced effects reflect the changes—whether in dollars or employment— that result from the household spending of direct workers, along with the employees in the supply chain.

Total Effects: The total of all economic effects is the size of the economic impact and is the sum of the direct and ripple effects. The IMPLAN model also tracks the tax effects associated with all the transactions and economic activity associated with the direct and ripple effects. For example, household spending at retailers generates state sales tax. In addition, those retailers also pay property taxes to local governments. As a result, this analysis was also able to estimate the state and local government tax flows.

Multiplier: The multiplier is the magnitude of the economic response in a particular geographic area associated with a change in the direct effects. The multiplier equals the total effect divided by the direct effect.

GDP: Also known as value added, GDP is a measure of the economic activity generated by a company, industry, state, nation, etc. GDP is the difference between total output (i.e., sales) and the cost of production inputs. GDP consists of four components: employee compensation, proprietor income, other property income and indirect business tax.

About IMPLAN Economic Modeling Software

IMPLAN is built on a mathematical input-output (I-O) model that expresses relationships between sectors of the economy in a chosen geographic location. In expressing the flow of dollars through a regional economy, the input-output model assumes fixed relationships between producers and their suppliers based on demand. It also omits any dollars spent outside of the regional economy—say, by producers who import raw goods from another area, or by employees who commute and do their household spending elsewhere.

The idea behind input-output modeling is that the inter-industry relationships within a region largely determine how that economy will respond to economic changes. In an I-O model, the increase in demand for a certain product or service causes a multiplier effect, layers of effect that come in a chain reaction. Increased demand for a product affects the producer of the product, the producer's employees, the producer's suppliers, the supplier's employees, and so on—ultimately generating a total effect in the economy that is greater than the initial change in demand. For instance, say demand for Andersen Windows' wood window products increases. Sales grow, so Andersen has to hire more people, and the company may buy more from local vendors, and those vendors in turn have to hire more people … who in turn buy more groceries. The ratio of that overall effect to the initial change is called a regional multiplier and can be expressed like this:

(Direct Effect + Indirect Effects + Induced Effects) / (Direct Effect) = Multiplier

Multipliers are industry- and region-specific. Each industry has a unique output multiplier, because each industry has a different pattern of purchases from firms inside and outside of the regional economy. (The output multiplier is in turn used to calculate income and employment multipliers.)

Estimating a multiplier is not the end goal of IMPLAN users. Most wish to estimate other numbers and get answers to questions such as: How many jobs will this new firm produce? How much will the local economy be affected by this plant closing? What will the effects be of an increase in product demand? Based on those user choices, IMPLAN software constructs "social accounts" to measure the flow of dollars from purchasers to producers within the region. The data in those social accounts will set up the precise equations needed to finally answer those questions users have—about the impact of a new company, a plant closing or greater product demand—and yield the answers.

IMPLAN constructs its input-output model using aggregated production, employment and trade data from local, regional and national sources, such as the U.S. Census Bureau's annual *County Business Patterns* report and the U.S. Bureau of Labor Statistics' annual report called *Covered Employment and Wages*. In addition to gathering enormous amounts of data from government sources, the company also estimates some data where they haven't been reported at the level of detail needed (county-level production data, for instance), or where detail is omitted in government reports to protect the confidentiality of individual companies whose data would be easily recognized due to a sparse population of businesses in the area.

The IBRC's analysts have attended advanced training in the use of the IMPLAN modeling software. The estimates that the IBRC analysts generate are scrutinized closely to ensure that they are accurate and reflect the most trustworthy application of the modeling software. In all instances, the most conservative estimation assumptions and procedures are used to produce the IMPLAN results.

Appendix 8.6 Black & Veatch Cost Estimate Review and Validation Report

BLACK & VEATCH COST ESTIMATE REVIEW AND VALIDATION REPORT

BLACK & VEATCH PROJECT NO. 400364

PREPARED FOR

Indianapolis Power & Light Company

JULY 2019

BLACK & VEATCH

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1.1 BLACK & VEATCH CORPORATION

The independent cost review was completed by cost estimating, engineering, and consulting professionals from Black & Veatch Corporation. Founded in 1915, Black & Veatch is a leading global engineering, consulting and construction company. Black & Veatch specializes in these major markets:

- Energy
- Water
- Telecommunications
- Federal
- Management Consulting

Black & Veatch Holding Company is an employee-owned, global company that delivers sustainable infrastructure solutions across the Power, Oil & Gas, Water, Telecommunications and Federal markets. Since 1915, we help clients improve the lives of people in communities worldwide through consulting, engineering, construction, operations and program management services.

1.2 T&D PLAN CAPITAL COST ESTIMATE REVIEW

IPL engaged Black & Veatch to conduct a review of IPL's proposed TDSIC Plan capital cost estimates and estimating process, based on Black & Veatch's knowledge and experience with similar TDSIC project capital cost estimates. The review tested estimates for reasonableness based on Black & Veatch's experience and the information and backup data received from IPL for its cost estimates.

The specific goals of the independent cost review were:

- To validate that the IPL cost estimating process is in accordance with AACE guidelines and
- To identify any recommendations for improvement.

Black & Veatch's review included IPL's cost estimating process for all projects and an independent estimate verification for a representative sample set of Class 2 project cost estimates from IPL's TDSIC plan as described in the following sub-sections. As part of the review, Black & Veatch supported IPL with the development of a uniform method and template for cost estimating to meet AACE Class 2, 3 and 4 guidelines for all project cost estimates. Class 3 and 4 estimate templates completed by IPL subject matter experts were reviewed by a Black & Veatch AACE certified estimator for reasonableness. Black & Veatch developed independent project estimates for a 5% sample of Class 2 project estimates to verify reasonableness of estimation and completeness of project details.

1.3 COST ESTIMATE REVIEW APPROACH

To conduct this review, IPL provided Black & Veatch detailed material and labor estimates developed by the designated IPL engineering subject matter experts and any required external engineering support. Each estimate provided line item details of costs that included quantities, materials, labor costs and any required assumptions. After reviewing the received estimate workbooks and documents, several cost estimating review discussions were conducted to confirm agreement on cost estimate classification criteria and to review IPL cost estimating methodology. Black & Veatch supported IPL with development of cost estimate templates for consistency across all project categories.

Black & Veatch reviewed the Class 3 and Class 4 estimates for the following projects:

1.) Circuit Rebuilds
2.) Substation Asset Replacement
3.) XLPE Cable Replacement
4.) 4 kV Conversion
5.) Tap Reliability Improvement Projects (TRIP)
6.) Meter Replacement
7.) Central Business District (CBD) Secondary Network Upgrades
8.) Static Wire Performance Improvement
9.) Remote Ends – Breaker Relays/ Upgrades
10.) Pole Replacements
11.) Steel Tower Life Extension
12.) Distribution Automation - Reclosers
13.) Deliverability – Substation Upgrades

Black & Veatch developed independent estimates for 5% of the Class 2 estimates that IPL had separately developed. The following projects were chosen to determine if IPL estimates were reasonable and complete for TDSIC purposes of "best estimate".

1. 4 kV Conversion – Stuart 4kv Conversion
2. CBD – Pierson St Phase #1
3. Circuit Rebuilds – Crestview #3
4. Circuit Rebuilds – Northwest #9
5. Substation – Edison Substation
6. Substation – Gardner Lane Substation
7. T-Line Static Replacement – 132-84 Mooresville to Camby
8. TRIP – Lafayette 5 Tap 192-141

1.3.1 IPL's Cost Estimating Approach

IPL developed project cost estimates for each project included in the proposed 7-year TDSIC investment plan; IPL estimated project costs using detailed estimation workbooks and systems supported by subject matter experts. These templates and systems allowed IPL cost estimators to develop estimates using a consistent set of base cost assumptions such as labor rates, material costs, and a variety of other assumptions to drive consistency with respect to its estimates.

Based on discussions with IPL's team, the cost estimates reviewed do not include an adjustment for salvage value of retired equipment/assets in the estimates. As such, Black & Veatch has not reviewed or assessed any estimates of salvage value. The cost estimates reviewed by Black & Veatch do include IPL overhead costs and contingency.

Class 2 estimates were developed for 9 of the 13 Projects for Year 1 and Year 2 of the plan. For the 4 remaining Projects, Class 3 estimates were developed. For the remaining years of the plan (Years 3-7) Class 4 estimates were used, except for the Advanced Distribution Management System (ADMS) Project. A Class 2 estimate was developed for the ADMS Project and the costs were distributed over the 3-year project deployment window.

Table 1 below, lists the three AACE estimate classes that are applicable to the IPL projects in the 7-year TDSIC plan.

Table 1 - AACE Estimate Classification Class 2-4

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed	L: -5% to -15% H: +5% to +20%

These project cost estimates are adjusted from Class 4 to Class 2 as part of IPL's annual TDSIC Plan update process, and when projects are between one and two years from being implemented, detailed project scopes are defined, and cost estimates are developed using the detailed estimation templates and systems.

1.3.2 B&V Approach for Review of T&D Project Cost Estimates

Black & Veatch's approach to complete the IPL Project cost estimate review included independent review of the cost estimating process, procedures and templates for all projects by a certified AACE estimator to confirm consistency with AACE guidelines. Black & Veatch also developed independent cost estimates for a 5% sample set of Class 2 estimates that IPL developed. Black & Veatch's certified AACE estimator, capital cost estimating tools and historical databases were used to develop Black & Veatch's independent estimate.

The independent review of the cost estimating process and templates were completed for all Class 2, Class 3 and Class 4 project estimates and included several review meetings with the IPL subject matter experts and supporting engineering firms to review the templates, and methodology utilized in the estimating process. Black & Veatch provided a detailed review of the AACE guidelines and industry good practice. Recommendations for improvement were provided throughout the review process to support IPL development of project cost estimates. To develop the independent Class 2 project estimates Black & Veatch relied on a templated approach previously applied to check other TDSIC cost estimates. This approach uses a combination of historical labor and material costs from past similar projects, as well as our compilation of material and labor costs for recent electric T&D projects across North America. We then compared the Black & Veatch developed estimates to the IPL estimates and calculated the percent difference in the estimates. Review of any differences were completed with the IPL subject matter experts in each discipline. Finally, Black & Veatch experience and professional judgment were used in completing this check for reasonableness and estimate documentation completeness. Appendix 8.8 of IPL's TDSIC Plan is an example of Class 2 Estimate Worksheet developed by collaboration between Black & Veatch and IPL to support IPL with consistent AACE Estimate Classifications System.

For the projects of a higher AACE Class level, including Class 3 and Class 4, the same level of detailed cost estimates is not available. This is appropriate in that these estimates are used for long term capital planning purposes at a stage where detailed project scope and estimates are not yet feasible. These estimates should include materials and labor assumptions details based on a typical installation. The typical installation included engineering resources, craft labor, and material unit costs. As projects develop from an initial planning stage, towards conceptual design and then to detailed design and procurement before being executed, different levels of detail with respect to the cost estimates are reasonable and consistent with AACE definitions. Appendix 8.10 of IPL's TDSIC Plan is an example of Class 4 Estimate Worksheet developed by collaboration between Black & Veatch and IPL to support IPL with consistent AACE Estimate Classifications System.

For all Class 2, Class 3 and Class 4 cost estimate reviews Black & Veatch used a combination of its professional judgment and experience with similar projects and assets, and review of the IPL estimating process using historical databases and cost estimating tools, and its understanding of the scope of the projects to determine if estimates were reasonable.

The Black & Veatch team performing this review included a team of:

- Senior power delivery cost estimators with 20+ years of experience and expertise in cost estimating for electric transmission and distribution projects.
- AACE certified cost estimator with 15+ years of industry estimating experience.
- Senior power industry project manager with 20+ years of experience planning and managing substantial projects.

1.4 COST ESTIMATE REVIEW RESULTS

Black & Veatch's initial review shows that the IPL cost estimates and cost estimating process are reasonable and consistent with AACE guideline classification. Based on Black & Veatch's review of the process and documentation developed to support each of the project estimates, IPL has utilized the correct AACE Class level to characterize what level of detail the cost estimates are developed to. The level of detail IPL uses to estimate T&D project cost estimates in its long-term T&D investment plan is consistent with good estimating practice within the industry. Additionally, Black & Veatch noted for several project categories, the IPL estimating process for projects in plan years 3-7 utilize a detailed unit cost basis to ensure best estimate of Class 4 project cost.

Table 2 below provides a summary of the AACE Class estimate used by year in the IPL TDSIC Plan.

Table 2 - AACE Class Estimate Used by Year

AACE CLASSIFICATION REVIEW BY PLAN YEAR			
Project Category	**Year 1 & 2**	**Year 3 – 7**	**Estimate Template Check Completed**
1. *Circuit Rebuilds*	*Class 2*	*Class 4*	*YES*
2. *Substation Assets*	*Class 2*	*Class 4*	*YES*
3. *XLPE Cable Replacement*	*Class 3*	*Class 4*	*YES*
4. *4 kV Conversion*	*Class 2*	*Class 4*	*YES*
5. *Tap Reliability Improvement Program*	*Class 2/ Class 4*	*Class 4*	*YES*
6. *Meter Replacement*	*Class 2*	*Class 4*	*YES*
7. *CBD Secondary Network*	*Class 2*	*Class 4*	*YES*
8. *Static Wire Performance Improvement*	*Class 2*	*Class 4*	*YES*
9. *Remote End - Breaker Relay/Upgrades*	*Class 2*	*Class 4*	*YES*
10. *Pole Replacements*	*Class 3*	*Class 4*	*YES*
11. *Steel Tower Life Extension*	*Class 3*	*Class 4*	*YES*
12. *Distribution Automation - Reclosers*	*Class 3*	*Class 4*	*YES*
13. *Deliverability – Substation Upgrades*	Class 2	Class 4	YES

When evaluating the Class 2 estimates in comparison to the Black & Veatch independent estimate many factors can cause significant changes in material and labor costs from month to month and year to year. In today's global economy, market forces impact major equipment suppliers and their costs frequently. These market impacts to costs are then passed on to equipment customers with resulting routine changes to material price quotes. Similarly, contract labor costs can fluctuate significantly in the energy industry based on demand. From a labor cost standpoint, many situations can change the level of effort required to complete a project. Unforeseen site conditions can increase the project duration significantly for one project, when at the same time on a similar project elsewhere the conditions are ideal, and the project duration can be less. This results in a variety of labor costs depending on a variety of factors.

It is in this context that Black & Veatch performed its review. No two cost estimators will arrive at the same cost estimate, even when given the same general scope description of a project. Differences can result from a variety of factors, including the following:

- When the cost estimate was developed – as discussed, market forces impact material prices every day and contract labor costs can fluctuate as demand for experienced labor changes.
- Understanding of site conditions and assumptions. Not all site conditions can be defined fully when estimating a project cost.

These uncertain factors with respect to cost estimates are important to keep in context, and it is with an understanding of this context that Black & Veatch performed its reasonableness review. For the review, IPL provided Black & Veatch "issue for construction" level project packages providing detailed design drawings, line item quantities and site-specific assumptions required to support development of an independent estimate. Additionally, where applicable, contract costs for material and labor estimates for specific planned projects were provided. Black & Veatch independently developed detailed cost estimates, using Black & Veatch estimating tools and historical labor and material costs and the same detailed breakdown used by IPL to compare with the Class 2 estimates provided for review. After the line item estimates were developed, Black & Veatch compared the total estimate to IPL's estimates to calculate a percent difference and assess the reasonableness of the estimate.

The Table 3 below is a summary of Black & Veatch's independent review effort of IPL's Class 2 estimates by project.

Table 3 - Summary of Black & Veatch's Independent Review of IPL Class 2 Estimates

CATEGORY	PROJECT DESCRIPTION	ESTIMATE COMPARISON % (BV TO IPL ESTIMATES)	REASONABLENESS REVIEW COMPLETED	AACE CLASS LEVEL	B&V REVIEWED ESTIMATE DOCUMENTATION
4kv Conversion	Stuart 4kv Conversion	Within +/- 5%	☒	2	☒
CBD	Pierson St Phase #1	Within +/- 5%	☒	2	☒
Circuit Rebuilds	Crestview #3	Within +/- 10%	☒	2	☒
Circuit Rebuilds	Northwest #9	Within +/- 15%	☒	2	☒
Substation	Edison Substation	Within +/- 15%	☒	2	☒
Substation	Gardner Lane Substation	Within +/- 10%	☒	2	☒
T-Line Static Wire Replacement	132-84 Mooresville to Camby	Within +/- 10%	☒	2	☒
TRIP	Lafayette 5 Tap 192-141	Within +/- 5%	☒	2	☒

Table 4 below shows the actual independent estimate results for each of the Class 2 projects in the sample set.

Table 4 - Summary of Black & Veatch and IPL Class 2 Estimate Comparison for 5% Sample Set

CATEGORY	PROJECT DESCRIPTION	BLACK & VEATCH	IPL	% DIFFERENCE
4kV Conversion	Stuart Conversion	$ 3,159,632	$ 3,234,494	+2.4%
CBD	Pierson St. #1	$ 1,062,441	$ 1,026,967	-3.3%
Circuit Rebuilds	Crestview #3	$ 2,437,759	$ 2,200,000	-9.8%
Circuit Rebuilds	Northwest #9	$ 2,534,184	$ 2,202,593	-13.1%
Substation	Edison Substation	$ 3,248,160	$ 3,719,828	+14.5%
Substation	Gardner Lane Substation	$ 1,289,338	$ 1,414,020	+9.7%

T-Line Static Wire Replacement	Mooresville - Camby	$ 1,691,672	$ 1,805,664	+6.7%
TRIP	Lafayette 5 Tap 192-141	$ 815,337	$ 859,608	+5.4%

As shown by Table 4, independent cost estimate verification for the 5% sample set of projects validated estimates for Class 2 projects are within +/- 15% which are consistent with the range of accuracy defined in the AACE guidelines shown in Table 1. All project packages reviewed had adequate documentation to meet good practice standards for the defined Class of estimate.

1.5 CONCLUSIONS

Black & Veatch's review of the process, templates and systems used to develop the IPL TDSIC Plan project cost estimates concludes that the project cost estimates reviewed are reasonable and within the typical band of uncertainty seen across the industry for capital planning and cost forecasting. Further, Black & Veatch concludes that the AACE Class levels reported by IPL are valid. Independent cost estimate verification of a 5% sample set of projects validated estimates for Class 2 projects are within +/- 15% providing a high confidence level these projects meet the expected accuracy range defined in the AACE guidelines. All project packages reviewed had adequate documentation to meet good estimating practice standards for the defined Class of estimate. Additionally, Black & Veatch concluded IPL has developed good estimating practice for labor cost estimates to reduce uncertainty through contracts and detailed unit cost reviews for Class 2, Class 3 and Class 4 level estimates.

Public Appendix 8.7 Cost Estimates, Year by Year Project Detail (Sortable List) and Plan Projects by FERC Account

Indianapolis Power & Light Company
7-Year TDSIC Plan by Project

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Project Type	2020	2021	2022	2023	2024	2025	2026	7-Year Total
	Age & Condition Projects								
1	Circuit Rebuilds	$ 27,175,955	$ 25,345,895	$ 45,810,667	$ 52,812,143	$ 47,773,667	$ 49,382,752	$ 49,913,886	$ 298,714,965
2	Substation Assets Replacement	$ 16,731,642	$ 27,023,779	$ 39,896,631	$ 39,220,541	$ 34,451,705	$ 44,283,282	$ 46,536,273	$ 248,143,853
3	XLPE Cable Replacement	$ 12,185,638	$ 11,768,208	$ 12,501,788	$ 12,354,210	$ 12,297,234	$ 12,829,535	$ 12,301,534	$ 86,238,147
4	4 kV Conversion	$ 19,709,314	$ 13,824,988	$ 15,422,783	$ 15,541,783	$ 7,583,329	$ 12,385,359	$ 7,520,673	$ 91,988,229
5	Tap Reliability Improvement Projects	$ 10,896,034	$ 10,404,000	$ 10,612,080	$ 10,824,322	$ 11,040,808	$ 11,261,624	$ 11,486,857	$ 76,525,725
6	Meter Replacement	$ 10,735,674	$ 10,950,388	$ 11,169,395	$ 11,392,783	$ 11,620,639	$ -	$ -	$ 55,868,879
7	CBD Secondary Network Upgrades	$ 4,585,019	$ 5,918,264	$ 5,311,051	$ 5,888,219	$ 5,001,613	$ 5,892,283	$ 6,373,447	$ 38,969,896
8	Static Wire Performance Improvement	$ 4,765,917	$ 6,881,909	$ 9,502,181	$ 11,200,958	$ 11,497,320	$ 10,679,473	$ 7,601,921	$ 62,129,679
9	Remote End - Breaker Relay/Upgrades	$ 3,042,255	$ 2,017,899	$ 5,578,433	$ 1,608,007	$ 6,234,867	$ 3,110,142	$ 6,425,834	$ 28,017,437
10	Pole Replacements	$ 3,256,134	$ 3,321,256	$ 3,387,682	$ 3,455,435	$ 3,524,544	$ 3,595,035	$ 3,666,935	$ 24,207,021
11	Steel Tower Life Extension	$ 1,138,320	$ 1,111,147	$ 1,082,432	$ 850,792	$ -	$ -	$ -	$ 4,182,691
12	**Age & Condition Projects Total**	$ 114,221,902	$ 118,567,733	$ 160,275,123	$ 165,149,193	$ 151,025,726	$ 153,919,485	$ 151,827,360	$ 1,014,986,522
	Deliverability Projects								
13	Distribution Automation	$ 18,815,340	$ 19,191,646	$ 13,644,103	$ 13,916,985	$ 14,195,325	$ 14,479,231	$ 14,768,816	$ 109,011,446
14	Substation Design Upgrades	$ 3,795,549	$ 16,213,025	$ 15,809,877	$ 32,905,072	$ 6,323,236	$ 16,777,568	$ 2,632,615	$ 94,456,942
15	**Deliverability Projects Total**	$ 22,610,889	$ 35,404,671	$ 29,453,980	$ 46,822,057	$ 20,518,561	$ 31,256,799	$ 17,401,431	$ 203,468,388
16	**Total Capital Costs**	$ 136,832,791	$ 153,972,404	$ 189,729,103	$ 211,971,250	$ 171,544,287	$ 185,176,284	$ 169,228,791	$ 1,218,454,910
17	Amount of Transmission	$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176	$ 30,641,731	$ 213,710,716
18	Amount of Distribution	$ 114,385,862	$ 126,396,966	$ 156,047,612	$ 175,545,958	$ 137,899,628	$ 155,881,108	$ 138,587,060	$ 1,004,744,194
19	**Total Capital Costs**	$ 136,832,791	$ 153,972,404	$ 189,729,103	$ 211,971,250	$ 171,544,287	$ 185,176,284	$ 169,228,791	$ 1,218,454,910

Indianapolis Power & Light Company
7-Year TDSIC Plan by FERC Account

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Project Type	2020	2021	2022	2023	2024	2025	2026	7-Year Total
	Transmission								
1	352 - Structures and Improvements	$ -	$ -	$ -	$ 2,300,385	$ 2,844,940	$ -	$ 2,632,615	$ 7,777,940
2	353 - Station Equipment	$ 16,542,692	$ 19,582,382	$ 23,096,878	$ 22,073,157	$ 19,302,399	$ 18,615,703	$ 20,407,195	$ 139,620,406
3	354 - Towers and Fixtures	$ 1,138,320	$ 1,111,147	$ 1,082,432	$ 850,792	$ -	$ -	$ -	$ 4,182,691
4	356 - Overhead Conductors and Devices	$ 4,765,917	$ 6,881,909	$ 9,502,181	$ 11,200,958	$ 11,497,320	$ 10,679,473	$ 7,601,921	$ 62,129,679
5	**Transmission Total**	$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176	$ 30,641,731	$ 213,710,716
	Distribution								
6	362 - Station Equipment	$ 7,026,754	$ 25,672,321	$ 38,188,063	$ 49,360,078	$ 24,862,469	$ 45,555,289	$ 32,554,913	$ 223,219,887
7	364 - Poles, Towers, and Fixtures	$ 39,069,911	$ 34,048,557	$ 47,918,689	$ 52,531,374	$ 44,678,960	$ 49,169,935	$ 46,385,522	$ 313,802,948
8	365 - Overhead Condustors and Devices	$ 28,815,380	$ 27,771,432	$ 26,078,201	$ 27,620,140	$ 25,686,598	$ 27,204,806	$ 26,696,855	$ 189,873,412
9	366 - Underground Conduit	$ 2,250,626	$ 2,346,110	$ 2,405,220	$ 2,690,012	$ 1,809,774	$ 2,715,591	$ 2,769,903	$ 16,987,236
10	367 - Underground Condustors and Devices	$ 13,966,103	$ 13,407,560	$ 14,443,018	$ 14,226,294	$ 14,093,313	$ 14,938,612	$ 14,497,783	$ 99,572,683
11	368 - Line Transformers	$ 12,521,414	$ 12,200,598	$ 15,845,026	$ 17,725,277	$ 15,147,875	$ 16,296,875	$ 15,682,084	$ 105,419,149
13	370.01 - Meters - Smart Meters	$ 10,735,674	$ 10,950,388	$ 11,169,395	$ 11,392,783	$ 11,620,639	$ -	$ -	$ 55,868,879
14	**Deliverability Total**	$ 114,385,862	$ 126,396,966	$ 156,047,612	$ 175,545,958	$ 137,899,628	$ 155,881,108	$ 138,587,060	$ 1,004,744,194
15	**Total Capital Costs**	$ 136,832,791	$ 153,972,404	$ 189,729,103	$ 211,971,250	$ 171,544,287	$ 185,176,284	$ 169,228,791	$ 1,218,454,910

Indianapolis Power & Light Company
7-Year TDSIC Plan by Project - Transmission

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Project Type	2020	2021	2022	2023	2024	2025	2026	7-Year Total
	Age & Condition Projects								
1	Circuit Rebuilds	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Substation Assets Replacement	$ 9,704,888	$ 18,155,088	$ 17,779,934	$ 6,785,036	$ 11,168,933	$ 16,408,152	$ 15,296,241	$ 95,298,272
3	XLPE Cable Replacement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	4 kV Conversion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Tap Reliability Improvement Projects	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Meter Replacement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	CBD Secondary Network Upgrades	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Static Wire Performance Improvement	$ 4,765,917	$ 6,881,909	$ 9,502,181	$ 11,200,958	$ 11,497,320	$ 10,679,473	$ 7,601,921	$ 62,129,679
9	Remote End - Breaker Relay/Upgrades	$ 3,042,255	$ 1,427,294	$ 5,316,944	$ 809,508	$ 4,655,170	$ 2,207,551	$ 5,110,954	$ 22,569,676
10	Pole Replacements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Steel Tower Life Extension	$ 1,138,320	$ 1,111,147	$ 1,082,432	$ 850,792	$ -	$ -	$ -	$ 4,182,691
12	**Age & Condition Projects Total**	$ 18,651,380	$ 27,575,438	$ 33,681,491	$ 19,646,294	$ 27,321,423	$ 29,295,176	$ 28,009,116	$ 184,180,318
	Deliverability Projects								
13	Distribution Automation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Substation Design Upgrades	$ 3,795,549	$ -	$ -	$ 16,778,998	$ 6,323,236	$ -	$ 2,632,615	$ 29,530,398
15	**Deliverability Projects Total**	$ 3,795,549	$ -	$ -	$ 16,778,998	$ 6,323,236	$ -	$ 2,632,615	$ 29,530,398
16	**Total Capital Costs**	$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176	$ 30,641,731	$ 213,710,716
17	Amount of Transmission	$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176	$ 30,641,731	$ 213,710,716
18	Amount of Distribution	$ 114,385,862	$ 126,396,966	$ 156,047,612	$ 175,545,958	$ 137,899,628	$ 155,881,108	$ 138,587,060	$ 1,004,744,194
19	**Total Capital Costs**	$ 136,832,791	$ 153,972,404	$ 189,729,103	$ 211,971,250	$ 171,544,287	$ 185,176,284	$ 169,228,791	$ 1,218,454,910

Indianapolis Power & Light Company
7-Year TDSIC Plan by Project - Distribution

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Project Type	2020	2021	2022	2023	2024	2025	2026	7-Year Total
	Age & Condition Projects								
1	Circuit Rebuilds	$ 27,175,955	$ 25,345,895	$ 45,810,667	$ 52,812,143	$ 47,773,667	$ 49,882,752	$ 49,913,886	$ 298,714,965
2	Substation Assets Replacement	$ 7,026,754	$ 8,868,691	$ 22,116,697	$ 32,435,505	$ 23,282,772	$ 27,875,130	$ 31,240,032	$ 152,845,581
3	XLPE Cable Replacement	$ 12,185,638	$ 11,768,203	$ 12,501,788	$ 12,354,210	$ 12,297,234	$ 12,829,535	$ 12,301,534	$ 86,238,147
4	4 kV Conversion	$ 19,709,314	$ 13,824,988	$ 15,422,783	$ 15,541,783	$ 7,583,329	$ 12,385,359	$ 7,520,673	$ 91,988,229
5	Tap Reliability Improvement Projects	$ 10,896,034	$ 10,404,000	$ 10,612,080	$ 10,824,322	$ 11,040,808	$ 11,261,624	$ 11,486,857	$ 76,525,725
6	Meter Replacement	$ 10,735,674	$ 10,950,388	$ 11,169,395	$ 11,392,783	$ 11,620,639	$ -	$ -	$ 55,868,879
7	CBD Secondary Network Upgrades	$ 4,585,019	$ 5,918,264	$ 5,311,051	$ 5,888,219	$ 5,001,613	$ 5,892,283	$ 6,373,447	$ 38,969,896
8	Static Wire Performance Improvement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Remote End - Breaker Relay/Upgrades	$ -	$ 590,605	$ 261,489	$ 798,499	$ 1,579,697	$ 902,591	$ 1,314,880	$ 5,447,761
10	Pole Replacements	$ 3,256,134	$ 3,321,256	$ 3,387,682	$ 3,455,435	$ 3,524,544	$ 3,595,035	$ 3,666,935	$ 24,207,021
11	Steel Tower Life Extension	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	**Age & Condition Projects Total**	$ 95,570,522	$ 90,992,295	$ 126,593,632	$ 145,502,899	$ 123,704,303	$ 124,624,309	$ 123,818,244	$ 830,806,204
	Deliverability Projects								
13	Distribution Automation	$ 18,815,340	$ 19,191,646	$ 13,644,103	$ 13,916,985	$ 14,195,325	$ 14,479,231	$ 14,768,816	$ 109,011,446
14	Substation Design Upgrades	$ -	$ 16,213,025	$ 15,809,877	$ 16,126,074	$ -	$ 16,777,568	$ -	$ 64,926,544
15	**Deliverability Projects Total**	$ 18,815,340	$ 35,404,671	$ 29,453,980	$ 30,043,059	$ 14,195,325	$ 31,256,799	$ 14,768,816	$ 173,937,990
16	**Total Capital Costs**	$ 114,385,862	$ 126,396,966	$ 156,047,612	$ 175,545,958	$ 137,899,628	$ 155,881,108	$ 138,587,060	$ 1,004,744,194
17	Amount of Transmission	$ 22,446,929	$ 27,575,438	$ 33,681,491	$ 36,425,292	$ 33,644,659	$ 29,295,176	$ 30,641,731	$ 213,710,716
18	Amount of Distribution	$ 114,385,862	$ 126,396,966	$ 156,047,612	$ 175,545,958	$ 137,899,628	$ 155,881,108	$ 138,587,060	$ 1,004,744,194
19	**Total Capital Costs**	$ 136,832,791	$ 153,972,404	$ 189,729,103	$ 211,971,250	$ 171,544,287	$ 185,176,284	$ 169,228,791	$ 1,218,454,910

Indianapolis Power & Light Company
2020 - TDSIC Project Detail - Capital Dollars Only

Line No.	(A) Age & Condition or Deliverability	(B) Project Type	(C) project	(D) Year	(E) Plan Project Cost (Capital Dollars)	(F) AACE Cost Estimate	(G) Quantity	(H) Units
1	Age & Condition	Circuit Rebuilds	CASTLETON NO. 4	2020	$ [redacted]	Class 2	[redacted]	Miles
2	Age & Condition	Circuit Rebuilds	CENTER NO. 7	2020	$ [redacted]	Class 2	[redacted]	Miles
3	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 6	2020	$ [redacted]	Class 2	[redacted]	Miles
4	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 10	2020	$ [redacted]	Class 2	[redacted]	Miles
5	Age & Condition	Circuit Rebuilds	MAYWOOD NO. 1	2020	$ [redacted]	Class 2	[redacted]	Miles
6	Age & Condition	Circuit Rebuilds	MAYWOOD NO. 2	2020	$ [redacted]	Class 2	[redacted]	Miles
7	Age & Condition	Circuit Rebuilds	MILL ST. NO. 7	2020	$ [redacted]	Class 2	[redacted]	Miles
8	Age & Condition	Circuit Rebuilds	MOORESVILLE NO. 6	2020	$ [redacted]	Class 2	[redacted]	Miles
9	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 3	2020	$ [redacted]	Class 2	[redacted]	Miles
10	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 4	2020	$ [redacted]	Class 2	[redacted]	Miles
11	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 9	2020	$ [redacted]	Class 2	[redacted]	Miles
12	Age & Condition	Circuit Rebuilds	WEST NO. 9	2020	$ [redacted]	Class 2	[redacted]	Miles
13	Age & Condition	Circuit Rebuilds	WESTLANE NO. 7	2020	$ [redacted]	Class 2	[redacted]	Miles
		Circuit Rebuilds Total			$ 27,175,955		[redacted]	
199	Age & Condition	Substation Assets Replacements	BRIDGEPORT	2020	$ [redacted]	Class 2	[redacted]	Units
200	Age & Condition	Substation Assets Replacements	CAMBY	2020	$ [redacted]	Class 2	[redacted]	Units
201	Age & Condition	Substation Assets Replacements	CRAWFORDSVILLE	2020	$ [redacted]	Class 2	[redacted]	Units
202	Age & Condition	Substation Assets Replacements	EDGEWOOD	2020	$ [redacted]	Class 2	[redacted]	Units
203	Age & Condition	Substation Assets Replacements	GARDNER LANE	2020	$ [redacted]	Class 2	[redacted]	Units
204	Age & Condition	Substation Assets Replacements	GEIST	2020	$ [redacted]	Class 2	[redacted]	Units
205	Age & Condition	Substation Assets Replacements	GLENS VALLEY	2020	$ [redacted]	Class 2	[redacted]	Units
206	Age & Condition	Substation Assets Replacements	INDIAN CREEK	2020	$ [redacted]	Class 2	[redacted]	Units
207	Age & Condition	Substation Assets Replacements	LILLY SOUTH	2020	$ [redacted]	Class 2	[redacted]	Units
208	Age & Condition	Substation Assets Replacements	METHODIST HOSPITAL	2020	$ [redacted]	Class 2	[redacted]	Units
209	Age & Condition	Substation Assets Replacements	MONON TRAIL	2020	$ [redacted]	Class 2	[redacted]	Units
210	Age & Condition	Substation Assets Replacements	POST ROAD	2020	$ [redacted]	Class 2	[redacted]	Units
211	Age & Condition	Substation Assets Replacements	RIVER ROAD	2020	$ [redacted]	Class 2	[redacted]	Units
212	Age & Condition	Substation Assets Replacements	ROCKVILLE	2020	$ [redacted]	Class 2	[redacted]	Units
213	Age & Condition	Substation Assets Replacements	SANITATION BELMONT	2020	$ [redacted]	Class 2	[redacted]	Units
214	Age & Condition	Substation Assets Replacements	SHEFFIELD	2020	$ [redacted]	Class 2	[redacted]	Units
215	Age & Condition	Substation Assets Replacements	SOUTHEAST	2020	$ [redacted]	Class 2	[redacted]	Units
216	Age & Condition	Substation Assets Replacements	ST. VINCENT	2020	$ [redacted]	Class 2	[redacted]	Units
217	Age & Condition	Substation Assets Replacements	STOUT GT YARD	2020	$ [redacted]	Class 2	[redacted]	Units
218	Age & Condition	Substation Assets Replacements	TOBEY	2020	$ [redacted]	Class 2	[redacted]	Units
219	Age & Condition	Substation Assets Replacements	UNITED AIRLINES	2020	$ [redacted]	Class 2	[redacted]	Units
220	Age & Condition	Substation Assets Replacements	WILLIAMS ST	2020	$ [redacted]	Class 2	[redacted]	Units
		Substation Assets Replacements Total			$ 16,731,642		[redacted]	
272	Age & Condition	XLPE Cable Replacement	XLPE Cable Replacements - 2020	2020	$ [redacted]	Class 3	[redacted]	Feet
		XLPE Cable Replacement Total			$ 12,185,638			

Indianapolis Power & Light Company
Cause No. 45264 TDSIC 1

Indianapolis Power & Light Company
2020 - TDSIC Project Detail - Capital Dollars Only

	(A)	(B)	(C)	(D)	(E)		(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)		AACE Cost Estimate	Quantity	Units
279	Age & Condition	4 kV Conversion	CONVERT KRISTEN TIE	2020	$	[redacted]	Class 2	[redacted]	Units
280	Age & Condition	4 kV Conversion	CONVERT MUNTER	2020	$	[redacted]	Class 2	[redacted]	Units
281	Age & Condition	4 kV Conversion	CONVERT KILDARE TIE	2020	$	[redacted]	Class 2	[redacted]	Units
282	Age & Condition	4 kV Conversion	CONVERT VERNON ACRES TIE	2020	$	[redacted]	Class 2	[redacted]	Units
283	Age & Condition	4 kV Conversion	CONVERT MARDENNA	2020	$	[redacted]	Class 2	[redacted]	Units
284	Age & Condition	4 kV Conversion	CONVERT FOREST MANOR TIE	2020	$	[redacted]	Class 2	[redacted]	Units
		4 kV Conversion Total			$	19,709,314			
324	Age & Condition	Tap Reliability Improvement Projects	Lawrence # 3 (3458-91)	2020	$	[redacted]	Class 2	[redacted]	Units
325	Age & Condition	Tap Reliability Improvement Projects	Post Rd #7 (281-B-6)	2020	$	[redacted]	Class 2	[redacted]	Units
326	Age & Condition	Tap Reliability Improvement Projects	Pike #3 (395-A-6)	2020	$	[redacted]	Class 2	[redacted]	Units
327	Age & Condition	Tap Reliability Improvement Projects	Mootsville #4 (M20-X-6)	2020	$	[redacted]	Class 2	[redacted]	Units
328	Age & Condition	Tap Reliability Improvement Projects	Lafayette #5 252-3,6	2020	$	[redacted]	Class 2	[redacted]	Units
329	Age & Condition	Tap Reliability Improvement Projects	Northeast # 6 (340-A-159)	2020	$	[redacted]	Class 2	[redacted]	Units
330	Age & Condition	Tap Reliability Improvement Projects	Parker #2 (260-B-192)	2020	$	[redacted]	Class 2	[redacted]	Units
331	Age & Condition	Tap Reliability Improvement Projects	Northeast #11 (372-72)	2020	$	[redacted]	Class 2	[redacted]	Units
332	Age & Condition	Tap Reliability Improvement Projects	Geist #4 (P109-208-B)	2020	$	[redacted]	Class 2	[redacted]	Units
333	Age & Condition	Tap Reliability Improvement Projects	Tremont #12 (4-200-B)	2020	$	[redacted]	Class 2	[redacted]	Units
334	Age & Condition	Tap Reliability Improvement Projects	Geist #6 (221-B)	2020	$	[redacted]	Class 2	[redacted]	Units
335	Age & Condition	Tap Reliability Improvement Projects	Parker #6 (315-39)	2020	$	[redacted]	Class 2	[redacted]	Units
336	Age & Condition	Tap Reliability Improvement Projects	Guion #8 (360-A-156)	2020	$	[redacted]	Class 2	[redacted]	Units
337	Age & Condition	Tap Reliability Improvement Projects	Guion #8 (12-360-A)	2020	$	[redacted]	Class 2	[redacted]	Units
338	Age & Condition	Tap Reliability Improvement Projects	Guion #8 (261-B-101)	2020	$	[redacted]	Class 2	[redacted]	Units
339	Age & Condition	Tap Reliability Improvement Projects	Northeast #11 (372-141)	2020	$	[redacted]	Class 2	[redacted]	Units
340	Age & Condition	Tap Reliability Improvement Projects	Tobey #7 (420-B-45)	2020	$	[redacted]	Class 2	[redacted]	Units
341	Age & Condition	Tap Reliability Improvement Projects	South #6 (700-A-140)	2020	$	[redacted]	Class 2	[redacted]	Units
342	Age & Condition	Tap Reliability Improvement Projects	Castleton #4 (P62-245-B)	2020	$	[redacted]	Class 2	[redacted]	Units
343	Age & Condition	Tap Reliability Improvement Projects	Castleton #4 (P117-245-B)	2020	$	[redacted]	Class 2	[redacted]	Units
		Tap Reliability Improvement Projects Total			$	10,896,034			
350	Age & Condition	Meter Replacement	Meter Replacement - 2020	2020	$	[redacted]	Class 3	[redacted]	Meters
		Meter Replacement Total			$	10,735,674			
355	Age & Condition	CBD Secondary Network Upgrades	Pierson #1	2020	$	[redacted]	Class 2	[redacted]	Units
356	Age & Condition	CBD Secondary Network Upgrades	DAS Route 1	2020	$	[redacted]	Class 2	[redacted]	Units
357	Age & Condition	CBD Secondary Network Upgrades	Feeder 621 Cable Replacement	2020	$	[redacted]	Class 2	[redacted]	Units
358	Age & Condition	CBD Secondary Network Upgrades	36 W Vermont Vault Upgrade	2020	$	[redacted]	Class 2	[redacted]	Units
359	Age & Condition	CBD Secondary Network Upgrades	431 N Penn Vault Upgrade	2020	$	[redacted]	Class 2	[redacted]	Units
360	Age & Condition	CBD Secondary Network Upgrades	Pierson #2	2020	$	[redacted]	Class 2	[redacted]	Units
361	Age & Condition	CBD Secondary Network Upgrades	Pierson #3	2020	$	[redacted]	Class 2	[redacted]	Units
		CBD Secondary Network Upgrades Total			$	4,585,019			
510	Age & Condition	Static Wire Performance Improvement	132-44 Crestview - Northeast	2020	$	[redacted]	Class 2	[redacted]	Miles

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	(A)	(B)	(C)	(D)	(E)		(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)		AACE Cost Estimate	Quantity	Units
511	Age & Condition	Static Wire Performance Improvement	132-84 Mooresville - Camby	2020	$	[redacted]	Class 2	[redacted]	Miles
512	Age & Condition	Static Wire Performance Improvement	132-24 MV Tap Switch - Mooresville	2020	$	[redacted]	Class 2	[redacted]	Miles
		Static Wire Performance Improvement Total			$	4,765,917		[redacted]	
535	Age & Condition	Remote End - Breaker Relay/Upgrades	CASTLETON-132-54 BKR - Relay	2020	$	[redacted]	Class 2	[redacted]	Units
536	Age & Condition	Remote End - Breaker Relay/Upgrades	CASTLETON-132-55 BKR - Relay	2020	$	[redacted]	Class 2	[redacted]	Units
537	Age & Condition	Remote End - Breaker Relay/Upgrades	MILL STREET-132-65 LINE BKR. - Relay	2020	$	[redacted]	Class 2	[redacted]	Units
538	Age & Condition	Remote End - Breaker Relay/Upgrades	SUNNYSIDE-132-46 BKR - Relay	2020	$	[redacted]	Class 2	[redacted]	Units
539	Age & Condition	Remote End - Breaker Relay/Upgrades	SANITATION BLMT-138 BUSTIE OCB - Breaker	2020	$	[redacted]	Class 2	[redacted]	Units
540	Age & Condition	Remote End - Breaker Relay/Upgrades	ROCKVILLE-132-64 BKR - Breaker	2020	$	[redacted]	Class 2	[redacted]	Units
541	Age & Condition	Remote End - Breaker Relay/Upgrades	GLENS VALLEY-BUS TIE BKR - Breaker	2020	$	[redacted]	Class 2	[redacted]	Units
		Remote End - Breaker Relay/Upgrades Total			$	3,042,255		[redacted]	
590	Age & Condition	Pole Replacements	Pole Replacement - 2020	2020	$	[redacted]	Class 3	[redacted]	Poles
591	Age & Condition	Pole Replacements	Pole Treatment - 2020	2020	$	[redacted]	Class 3	[redacted]	Poles
		Pole Replacements Total			$	3,256,134		[redacted]	
604	Age & Condition	Steel Tower Life Extension	Steel Tower Life Extension - 2020	2020	$	[redacted]	Class 3	[redacted]	Structures
		Steel Tower Life Extension Total			$	1,138,320		[redacted]	
608	Deliverability	Distribution Automation	Reclosers - 2020	2020	$	[redacted]	Class 4	[redacted]	Reclosers
615	Deliverability	Distribution Automation	Advanced Distribution Management System - 2020	2020	$	[redacted]	Class 3	[redacted]	Units
		Distribution Automation Total			$	18,815,340		[redacted]	
617	Deliverability	Substation Design Upgrades	Rockville Sub - Add Breaker & Create Ring Bus	2020	$	[redacted]	Class 2	[redacted]	Units
618	Deliverability	Substation Design Upgrades	Prospect - Add 138kv Breaker	2020	$	[redacted]	Class 2	[redacted]	Units
		Substation Design Upgrades Total			$	3,795,549			
		Grand Total			$	136,832,791			

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
14	Age & Condition	Circuit Rebuilds	CENTER NO. 3	2021	$ [redacted]	Class 2	[redacted]	Miles
15	Age & Condition	Circuit Rebuilds	CENTER NO. 6	2021	$	Class 2		Miles
16	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 1	2021	$	Class 2		Miles
17	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 3	2021	$	Class 2		Miles
18	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 8	2021	$	Class 2		Miles
19	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 3	2021	$	Class 2		Miles
20	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 4	2021	$	Class 2		Miles
21	Age & Condition	Circuit Rebuilds	MILL ST. NO. 4	2021	$	Class 2		Miles
22	Age & Condition	Circuit Rebuilds	MILL ST. NO. 9	2021	$	Class 2		Miles
23	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 1	2021	$	Class 2		Miles
24	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 2	2021	$	Class 2		Miles
25	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 1	2021	$	Class 2		Miles
26	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 3	2021	$	Class 2		Miles
27	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 5	2021	$	Class 2		Miles
28	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 7	2021	$	Class 2		Miles
29	Age & Condition	Circuit Rebuilds	WEST NO. 2	2021	$	Class 2		Miles
30	Age & Condition	Circuit Rebuilds	WEST NO. 10	2021	$	Class 2		Miles
		Circuit Rebuilds Total			$ 25,345,895			
221	Age & Condition	Substation Assets Replacements	ALLISON #4	2021	$ [redacted]	Class 2		Units
222	Age & Condition	Substation Assets Replacements	CENTER	2021	$	Class 2		Units
223	Age & Condition	Substation Assets Replacements	CRESTVIEW	2021	$	Class 2		Units
224	Age & Condition	Substation Assets Replacements	EDISON	2021	$	Class 2		Units
225	Age & Condition	Substation Assets Replacements	GUION	2021	$	Class 2		Units
226	Age & Condition	Substation Assets Replacements	HANNA	2021	$	Class 2		Units
227	Age & Condition	Substation Assets Replacements	I.C.E.	2021	$	Class 2		Units
228	Age & Condition	Substation Assets Replacements	I.U.CAMPUS SOUTH	2021	$	Class 2		Units
229	Age & Condition	Substation Assets Replacements	LILLY CORP	2021	$	Class 2		Units
230	Age & Condition	Substation Assets Replacements	MOORESVILLE	2021	$	Class 2		Units
231	Age & Condition	Substation Assets Replacements	PARK FLETCHER	2021	$	Class 2		Units
232	Age & Condition	Substation Assets Replacements	QUEMETCO	2021	$	Class 2		Units
233	Age & Condition	Substation Assets Replacements	WATER CO WHITE RIV IND SUB	2021	$	Class 2		Units
234	Age & Condition	Substation Assets Replacements	WESTLANE	2021	$	Class 2		Units
		Substation Assets Replacements Total			$ 27,023,779			
273	Age & Condition	XLPE Cable Replacement	**XLPE Cable Replacements - 2021**	2021	$ [redacted]	Class 3		Feet
		XLPE Cable Replacement Total			$ 11,768,208			
285	Age & Condition	4 kV Conversion	CONVERT MILLERSVILLE TIE	2021	$ [redacted]	Class 2		Units
286	Age & Condition	4 kV Conversion	CONVERT GALE TIE	2021	$	Class 2		Units
287	Age & Condition	4 kV Conversion	CONVERT EUCLID TIE	2021	$	Class 2		Units
288	Age & Condition	4 kV Conversion	CONVERT STUART	2021	$	Class 2		Units

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
		4 kV Conversion Total			$ 13,824,925			
344	Age & Condition	Tap Reliability Improvement Projects	TRIP - 2021	2021	$ [redacted]	Class 4	[redacted]	Units
		Tap Reliability Improvement Projects Total			$ 10,404,000		[redacted]	
351	Age & Condition	Meter Replacement	Meter Replacement - 2021	2021	$ [redacted]	Class 3	[redacted]	Meters
		Meter Replacement Total			$ 10,950,388		[redacted]	
362	Age & Condition	CBD Secondary Network Upgrades	128 W Georgia St Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
363	Age & Condition	CBD Secondary Network Upgrades	Feeder 661 Cable Replacement	2021	$ [redacted]	Class 2	[redacted]	Units
364	Age & Condition	CBD Secondary Network Upgrades	Feeder 451 Cable Replacement	2021	$ [redacted]	Class 2	[redacted]	Units
365	Age & Condition	CBD Secondary Network Upgrades	Feeder 461 Cable Replacement	2021	$ [redacted]	Class 2	[redacted]	Units
266	Age & Condition	CBD Secondary Network Upgrades	25 W Georgia St. Vault Upgr	2021	$ [redacted]	Class 2	[redacted]	Units
367	Age & Condition	CBD Secondary Network Upgrades	19 N. Meridian St. Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
368	Age & Condition	CBD Secondary Network Upgrades	215 W. New York St. Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
369	Age & Condition	CBD Secondary Network Upgrades	108 E Market St Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
370	Age & Condition	CBD Secondary Network Upgrades	121 Monument Circle Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
371	Age & Condition	CBD Secondary Network Upgrades	108 E Maryland St Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
272	Age & Condition	CBD Secondary Network Upgrades	150 E Market St Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
373	Age & Condition	CBD Secondary Network Upgrades	26 E Ohio St Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
374	Age & Condition	CBD Secondary Network Upgrades	110 N Scioto St Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
375	Age & Condition	CBD Secondary Network Upgrades	Pierson #6	2021	$ [redacted]	Class 2	[redacted]	Units
376	Age & Condition	CBD Secondary Network Upgrades	Pierson #5	2021	$ [redacted]	Class 2	[redacted]	Units
377	Age & Condition	CBD Secondary Network Upgrades	117 E Michigan St Vault Upgrade	2021	$ [redacted]	Class 2	[redacted]	Units
378	Age & Condition	CBD Secondary Network Upgrades	Pierson #4	2021	$ [redacted]	Class 2	[redacted]	Units
379	Age & Condition	CBD Secondary Network Upgrades	OTS Route 1 Extension	2021	$ [redacted]	Class 2	[redacted]	Units
		CBD Secondary Network Upgrades Total			$ 5,918,264		[redacted]	
513	Age & Condition	Static Wire Performance Improvement	132-35 Pike - Crawfordsville Rd	2021	$ [redacted]	Class 2	[redacted]	Miles
514	Age & Condition	Static Wire Performance Improvement	132-05 Stout - Glenns Valley	2021	$ [redacted]	Class 2	[redacted]	Miles
515	Age & Condition	Static Wire Performance Improvement	132-59 Southwest - Sanitation Southport	2021	$ [redacted]	Class 2	[redacted]	Miles
516	Age & Condition	Static Wire Performance Improvement	132-70 Allison #4 - West	2021	$ [redacted]	Class 2	[redacted]	Miles
517	Age & Condition	Static Wire Performance Improvement	132-61 Center - Lilly South	2021	$ [redacted]	Class 2	[redacted]	Miles
518	Age & Condition	Static Wire Performance Improvement	2451-1 Center - Lilly Corp	2021	$ [redacted]	Class 2	[redacted]	Miles
		Static Wire Performance Improvement Total			$ 6,881,909		[redacted]	
542	Age & Condition	Remote End - Breaker Relay/Upgrades	LILLY-SOUTH-132-61 BKR - Relay	2021	$ [redacted]	Class 2	[redacted]	Units
543	Age & Condition	Remote End - Breaker Relay/Upgrades	LILLY CORP-2451-1 BKR - Relay	2021	$ [redacted]	Class 2	[redacted]	Units
544	Age & Condition	Remote End - Breaker Relay/Upgrades	ENGLISH AVE-2471-1 BREAKER - Relay	2021	$ [redacted]	Class 2	[redacted]	Units
545	Age & Condition	Remote End - Breaker Relay/Upgrades	STOUT SOUTH YARD - Relay	2021	$ [redacted]	Class 2	[redacted]	Units
546	Age & Condition	Remote End - Breaker Relay/Upgrades	I.C.E.-BUS TIE BREAKER - Relay	2021	$ [redacted]	Class 2	[redacted]	Units
547	Age & Condition	Remote End - Breaker Relay/Upgrades	CRESTVIEW-138KV BUS TIE BKR - Breaker & Relay	2021	$ [redacted]	Class 2	[redacted]	Units
548	Age & Condition	Remote End - Breaker Relay/Upgrades	WEST-132-70W BKR - Relay	2021	$ [redacted]	Class 2	[redacted]	Units
549	Age & Condition	Remote End - Breaker Relay/Upgrades	WEST-132-63 BKR - Relay	2021	$ [redacted]	Class 2	[redacted]	Units

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
		Remote End - Breaker Relay/Upgrades Total			$ 2,017,899		[redacted]	
592	Age & Condition	Pole Replacements	Pole Replacement - 2021	2021	$ [redacted]	Class 3	[redacted]	Poles
593	Age & Condition	Pole Replacements	Pole Treatment - 2021	2021	$ [redacted]	Class 3	[redacted]	Poles
		Pole Replacements Total			$ 3,321,256		[redacted]	
605	Age & Condition	Steel Tower Life Extension	Steel Tower Life Extension - 2021	2021	$ [redacted]	Class 3	[redacted]	Structures
		Steel Tower Life Extension Total			$ 1,111,147		[redacted]	
609	Deliverability	Distribution Automation	Reclosers - 2021	2021	$ [redacted]	Class 4	[redacted]	Reclosers
616	Deliverability	Distribution Automation	Advanced Distribution Management System - 2021	2021	$ [redacted]	Class 3	[redacted]	Units
		Distribution Automation Total			$ 19,191,646		[redacted]	
619	Deliverability	Substation Design Upgrades	Center Sub - Rebuild and Reconfigure	2021	$ [redacted]	Class 2	[redacted]	Units
620	Deliverability	Substation Design Upgrades	Mooresville - Sub Reconfigure	2021	$ [redacted]	Class 2	[redacted]	Units
		Substation Design Upgrades Total			$ 16,213,029			
		Grand Total			$ 193,972,404			

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (C[redacted]	AACE Cost Estimate	Quantity	Units
31	Age & Condition	Circuit Rebuilds	CENTER NO. 8	2022	$ [redacted]	Class 4	[redacted]	Miles
32	Age & Condition	Circuit Rebuilds	CENTER NO. 10	2022	$	Class 4		Miles
33	Age & Condition	Circuit Rebuilds	EAST NO. 1	2022	$	Class 4		Miles
34	Age & Condition	Circuit Rebuilds	EDGEWOOD NO. 9	2022	$	Class 4		Miles
35	Age & Condition	Circuit Rebuilds	GERMAN CHURCH NO. 9	2022	$	Class 4		Miles
36	Age & Condition	Circuit Rebuilds	GUION NO. 5	2022	$	Class 4		Miles
37	Age & Condition	Circuit Rebuilds	GUION NO. 6	2022	$	Class 4		Miles
38	Age & Condition	Circuit Rebuilds	GUION NO. 7	2022	$	Class 4		Miles
39	Age & Condition	Circuit Rebuilds	INDIAN CREEK NO. 3	2022	$	Class 4		Miles
40	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 8	2022	$	Class 4		Miles
41	Age & Condition	Circuit Rebuilds	MILL ST. NO. 1	2022	$	Class 4		Miles
42	Age & Condition	Circuit Rebuilds	MILL ST. NO. 3	2022	$	Class 4		Miles
43	Age & Condition	Circuit Rebuilds	MILL ST. NO. 5	2022	$	Class 4		Miles
44	Age & Condition	Circuit Rebuilds	MONON TRAIL NO. 1	2022	$	Class 4		Miles
45	Age & Condition	Circuit Rebuilds	MONROVIA NO. 1	2022	$	Class 4		Miles
46	Age & Condition	Circuit Rebuilds	MOORESVILLE NO. 1	2022	$	Class 4		Miles
47	Age & Condition	Circuit Rebuilds	NORTH NO. 2	2022	$	Class 4		Miles
48	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 12	2022	$	Class 4		Miles
49	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 2	2022	$	Class 4		Miles
50	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 4	2022	$	Class 4		Miles
51	Age & Condition	Circuit Rebuilds	PARK FLETCHER NO. 4	2022	$	Class 4		Miles
52	Age & Condition	Circuit Rebuilds	PARKER NO. 2	2022	$	Class 4		Miles
53	Age & Condition	Circuit Rebuilds	PROSPECT NO. 5	2022	$	Class 4		Miles
54	Age & Condition	Circuit Rebuilds	QUEMETCO NO. 1	2022	$	Class 4		Miles
55	Age & Condition	Circuit Rebuilds	RCA E 30TH NO. 1	2022	$	Class 4		Miles
56	Age & Condition	Circuit Rebuilds	RCA E 30TH NO. 2	2022	$	Class 4		Miles
57	Age & Condition	Circuit Rebuilds	RIVER ROAD NO. 5	2022	$	Class 4		Miles
58	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 2	2022	$	Class 4		Miles
59	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 4	2022	$	Class 4		Miles
60	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 7	2022	$	Class 4		Miles
61	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 8	2022	$	Class 4		Miles
62	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 9	2022	$	Class 4		Miles
63	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 10	2022	$	Class 4		Miles
64	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 16	2022	$	Class 4		Miles
65	Age & Condition	Circuit Rebuilds	SHEFFIELD NO. 2	2022	$	Class 4		Miles
66	Age & Condition	Circuit Rebuilds	SHEFFIELD NO. 4	2022	$	Class 4		Miles
67	Age & Condition	Circuit Rebuilds	SHEFFIELD NO. 5	2022	$	Class 4		Miles
68	Age & Condition	Circuit Rebuilds	SOUTH NO. 4	2022	$	Class 4		Miles
69	Age & Condition	Circuit Rebuilds	SOUTH NO. 6	2022	$	Class 4		Miles

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Line No.	Age & Condition or Deliverability	Project Type	project	Year		Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
70	Age & Condition	Circuit Rebuilds	SOUTH NO. 10	2022	$	[redacted]	Class 4	[redacted]	Miles
71	Age & Condition	Circuit Rebuilds	SOUTHPORT NO. 6	2022	$	[redacted]	Class 4	[redacted]	Miles
72	Age & Condition	Circuit Rebuilds	THOMPSON NO. 3	2022	$	[redacted]	Class 4	[redacted]	Miles
73	Age & Condition	Circuit Rebuilds	THOMPSON NO. 5	2022	$	[redacted]	Class 4	[redacted]	Miles
74	Age & Condition	Circuit Rebuilds	TOBEY NO. 7	2022	$	[redacted]	Class 4	[redacted]	Miles
75	Age & Condition	Circuit Rebuilds	TOBEY NO. 10	2022	$	[redacted]	Class 4	[redacted]	Miles
76	Age & Condition	Circuit Rebuilds	TREMONT NO. 2	2022	$	[redacted]	Class 4	[redacted]	Miles
77	Age & Condition	Circuit Rebuilds	TREMONT NO. 7	2022	$	[redacted]	Class 4	[redacted]	Miles
78	Age & Condition	Circuit Rebuilds	TREMONT NO. 10	2022	$	[redacted]	Class 4	[redacted]	Miles
79	Age & Condition	Circuit Rebuilds	WEST NO. 1	2022	$	[redacted]	Class 4	[redacted]	Miles
80	Age & Condition	Circuit Rebuilds	WILLIAMS NO. 2	2022	$	[redacted]	Class 4	[redacted]	Miles
81	Age & Condition	Circuit Rebuilds	WILLIAMS NO. 5	2022	$	[redacted]	Class 4	[redacted]	Miles
		Circuit Rebuilds Total			$	45,810,667		[redacted]	
235	Age & Condition	Substation Assets Replacements	CASTLETON	2022	$	[redacted]	Class 4	[redacted]	Units
236	Age & Condition	Substation Assets Replacements	CUMBERLAND	2022	$	[redacted]	Class 4	[redacted]	Units
237	Age & Condition	Substation Assets Replacements	GEORGETOWN	2022	$	[redacted]	Class 4	[redacted]	Units
238	Age & Condition	Substation Assets Replacements	GERMAN CHURCH	2022	$	[redacted]	Class 4	[redacted]	Units
239	Age & Condition	Substation Assets Replacements	LAFAYETTE ROAD	2022	$	[redacted]	Class 4	[redacted]	Units
240	Age & Condition	Substation Assets Replacements	DOW ELANCO	2022	$	[redacted]	Class 4	[redacted]	Units
241	Age & Condition	Substation Assets Replacements	I.U. MED. CENTER	2022	$	[redacted]	Class 4	[redacted]	Units
242	Age & Condition	Substation Assets Replacements	ROACH CHEM.	2022	$	[redacted]	Class 4	[redacted]	Units
243	Age & Condition	Substation Assets Replacements	STOUT	2022	$	[redacted]	Class 4	[redacted]	Units
244	Age & Condition	Substation Assets Replacements	PETERSBURG	2022	$	[redacted]	Class 4	[redacted]	Units
245	Age & Condition	Substation Assets Replacements	PIKE	2022	$	[redacted]	Class 4	[redacted]	Units
246	Age & Condition	Substation Assets Replacements	STOUT SOUTH YARD	2022	$	[redacted]	Class 4	[redacted]	Units
247	Age & Condition	Substation Assets Replacements	THOMPSON	2022	$	[redacted]	Class 4	[redacted]	Units
248	Age & Condition	Substation Assets Replacements	TREMONT	2022	$	[redacted]	Class 4	[redacted]	Units
		Substation Assets Replacements Total			$	39,896,631		[redacted]	
274	Age & Condition	XLPE Cable Replacement	**XLPE Cable Replacements - 2022**	2022	$	[redacted]	Class 4	[redacted]	Feet
		XLPE Cable Replacement Total			$	12,501,788		[redacted]	
289	Age & Condition	4 kV Conversion	CONVERT DOUGLAS	2022	$	[redacted]	Class 4	[redacted]	Units
290	Age & Condition	4 kV Conversion	CONVERT SANGSTER	2022	$	[redacted]	Class 4	[redacted]	Units
291	Age & Condition	4 kV Conversion	CONVERT FLAKE	2022	$	[redacted]	Class 4	[redacted]	Units
292	Age & Condition	4 kV Conversion	CONVERT OXFORD	2022	$	[redacted]	Class 4	[redacted]	Units
293	Age & Condition	4 kV Conversion	CONVERT CAROLINE TIE	2022	$	[redacted]	Class 4	[redacted]	Units
294	Age & Condition	4 kV Conversion	CONVERT CAROLINE - EMER	2022	$	[redacted]	Class 4	[redacted]	Units
295	Age & Condition	4 kV Conversion	CONVERT RALSTON	2022	$	[redacted]	Class 4	[redacted]	Units
		4 kV Conversion Total			$	15,422,783		[redacted]	
345	Age & Condition	Tap Reliability Improvement Projects	TRIP - 2022	2022	$	[redacted]	Class 4	[redacted]	Units

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
		Tap Reliability Improvement Projects Total			$ 10,612,080			
352	Age & Condition	Meter Replacement	Meter Replacement - 2022	2022	$ [redacted]	Class 4	[redacted]	Meters
		Meter Replacement Total			$ 11,169,395			
380	Age & Condition	CBD Secondary Network Upgrades	New Pre-Cast Manhole (Location vic. Pierson and Michigan)	2022	$ [redacted]	Class 4	[redacted]	Units
381	Age & Condition	CBD Secondary Network Upgrades	New Pre-Cast Manhole (Location vic. Illinois and Michigan)	2022	$ [redacted]	Class 4	[redacted]	Units
382	Age & Condition	CBD Secondary Network Upgrades	New Pre-Cast Manhole (Location vic. 535 N. Illinois)	2022	$ [redacted]	Class 4	[redacted]	Units
383	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH I15-11	2022	$ [redacted]	Class 4	[redacted]	Units
384	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH I15-00	2022	$ [redacted]	Class 4	[redacted]	Units
385	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH I16-02	2022	$ [redacted]	Class 4	[redacted]	Units
386	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH I16-03	2022	$ [redacted]	Class 4	[redacted]	Units
387	Age & Condition	CBD Secondary Network Upgrades	Duct Line WR1 (186 ft.) Location vic. Pierson and Michigan	2022	$ [redacted]	Class 4	[redacted]	Units
388	Age & Condition	CBD Secondary Network Upgrades	Duct Line WR2 (67 ft.) Location vic. Illinois and Michigan	2022	$ [redacted]	Class 4	[redacted]	Units
389	Age & Condition	CBD Secondary Network Upgrades	Duct Line WR3 (239 ft.) Location vic. Illinois and Michigan	2022	$ [redacted]	Class 4	[redacted]	Units
390	Age & Condition	CBD Secondary Network Upgrades	Duct Line WR4 (110 ft.) Location vic. 535 N. Illinois	2022	$ [redacted]	Class 4	[redacted]	Units
391	Age & Condition	CBD Secondary Network Upgrades	Duct Line WR5 (294 ft.) Location vic. Pierson and Michigan	2022	$ [redacted]	Class 4	[redacted]	Units
392	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 108 E. Market, UG412	2022	$ [redacted]	Class 4	[redacted]	Units
393	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 121 Monument Circle, UG422	2022	$ [redacted]	Class 4	[redacted]	Units
394	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 128 W. Georgia, UG 641	2022	$ [redacted]	Class 4	[redacted]	Units
395	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG462 108 E. Market	2022	$ [redacted]	Class 4	[redacted]	Units
396	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG422 121 Monument Circle	2022	$ [redacted]	Class 4	[redacted]	Units
397	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG432 2 W. Washington	2022	$ [redacted]	Class 4	[redacted]	Units
398	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, 317 W. Michigan	2022	$ [redacted]	Class 4	[redacted]	Units
399	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 572 ft) MH I15-00 to MH I16-02	2022	$ [redacted]	Class 4	[redacted]	Units
400	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 907 ft) MH I15-01 to MH I15-97	2022	$ [redacted]	Class 4	[redacted]	Units
401	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 1128 ft) MH I15-07 to MH I14-00	2022	$ [redacted]	Class 4	[redacted]	Units
402	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cicuit 631 (Length 1,924 ft)	2022	$ [redacted]	Class 4	[redacted]	Units
403	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Edison Circuit 453 (Length 4,612 ft)	2022	$ [redacted]	Class 4	[redacted]	Units
404	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable with Manholes (Length 1,294 ft) MH in Year	2022	$ [redacted]	Class 4	[redacted]	Units
405	Age & Condition	CBD Secondary Network Upgrades	Real Time DTS Monitoring (Mass. Ave. network Quadrant)	2022	$ [redacted]	Class 4	[redacted]	Units
406	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 400 W. Washington, 44 N. Senate	2022	$ [redacted]	Class 4	[redacted]	Units
407	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 110 N. Senate, 46 N. Capital	2022	$ [redacted]	Class 4	[redacted]	Units
408	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 320 W. Washington, 309 W. Washington	2022	$ [redacted]	Class 4	[redacted]	Units
409	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 10 S. Capital, 202 W. Maryland, 128 W. Georgia	2022	$ [redacted]	Class 4	[redacted]	Units
		CBD Secondary Network Upgrades Total			$ 5,311,051			
519	Age & Condition	Static Wire Performance Improvement	132-36 Edison - Brookwood	2022	$ [redacted]	Class 4	[redacted]	Miles
520	Age & Condition	Static Wire Performance Improvement	132-41 Westlane - Georgetown	2022	$ [redacted]	Class 4	[redacted]	Miles
521	Age & Condition	Static Wire Performance Improvement	132-28 Prospect - Ford	2022	$ [redacted]	Class 4	[redacted]	Miles
		Static Wire Performance Improvement Total			$ 9,502,181			
550	Age & Condition	Remote End - Breaker Relay/Upgrades	GLENS VALLEY-BUS TIE BKR - Relay	2022	$ [redacted]	Class 4	[redacted]	Units

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
551	Age & Condition	Remote End - Breaker Relay/Upgrades	IU CAMPUS N-3331-1 BKR - Relay	2022	$ [redacted]	Class 4	[redacted]	Units
552	Age & Condition	Remote End - Breaker Relay/Upgrades	LAWRENCE-132-48 BREAKER - Breaker	2022	$	Class 4		Units
553	Age & Condition	Remote End - Breaker Relay/Upgrades	STOUT N-132-14 WEST OCB - Breaker	2022	$	Class 4		Units
554	Age & Condition	Remote End - Breaker Relay/Upgrades	STOUT N-132-14 EAST OCB - Breaker & Relay	2022	$	Class 4		Units
555	Age & Condition	Remote End - Breaker Relay/Upgrades	MILL STREET-132-65 LINE BKR. - Breaker	2022	$	Class 4		Units
556	Age & Condition	Remote End - Breaker Relay/Upgrades	STOUT N-138-99 EAST OCB - Breaker & Relay	2022	$	Class 4		Units
557	Age & Condition	Remote End - Breaker Relay/Upgrades	STOUT N-138-99 WEST OCB - Breaker	2022	$	Class 4		Units
		Remote End - Breaker Relay/Upgrades Total			$ 9,578,433			
564	Age & Condition	Pole Replacements	Pole Replacement - 2022	2022	$ [redacted]	Class 4		Poles
565	Age & Condition	Pole Replacements	Pole Treatment - 2022	2022	$	Class 4		Poles
		Pole Replacements Total			$ 3,387,682			
606	Age & Condition	Steel Tower Life Extension	Steel Tower Life Extension - 2022	2022	$ [redacted]	Class 4		Structures
		Steel Tower Life Extension Total			$ 1,082,432			
610	Deliverability	Distribution Automation	Reclosers - 2022	2022	$ [redacted]	Class 4		Reclosers
		Distribution Automation Total			$ 13,644,103			
621	Deliverability	Substation Design Upgrades	New 13.2kv Sub for 4kv Conversion	2022	$ [redacted]	Class 4		Units
		Substation Design Upgrades Total			$ 15,809,877			
		Grand Total			$ 189,729,103			

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	(A)	(B)	(C)	(D)	(E)		(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)		AACE Cost Estimate	Quantity	Units
82	Age & Condition	Circuit Rebuilds	CASTLETON NO. 7	2023	$	[redacted]	Class 4	[redacted]	Miles
83	Age & Condition	Circuit Rebuilds	CASTLETON NO. 8	2023	$	[redacted]	Class 4	[redacted]	Miles
84	Age & Condition	Circuit Rebuilds	CASTLETON NO. 17	2023	$	[redacted]	Class 4	[redacted]	Miles
85	Age & Condition	Circuit Rebuilds	CRAWFORDSVILLE NO. 2	2023	$	[redacted]	Class 4	[redacted]	Miles
86	Age & Condition	Circuit Rebuilds	EAST NO. 4	2023	$	[redacted]	Class 4	[redacted]	Miles
87	Age & Condition	Circuit Rebuilds	EAST NO. 8	2023	$	[redacted]	Class 4	[redacted]	Miles
88	Age & Condition	Circuit Rebuilds	EDGEWOOD NO. 5	2023	$	[redacted]	Class 4	[redacted]	Miles
89	Age & Condition	Circuit Rebuilds	FRANKLIN TWNSHP NO. 2	2023	$	[redacted]	Class 4	[redacted]	Miles
90	Age & Condition	Circuit Rebuilds	GERMAN CHURCH NO. 4	2023	$	[redacted]	Class 4	[redacted]	Miles
91	Age & Condition	Circuit Rebuilds	GLENNS VALLEY NO. 2	2023	$	[redacted]	Class 4	[redacted]	Miles
92	Age & Condition	Circuit Rebuilds	LAFAYETTE ROAD NO. 3	2023	$	[redacted]	Class 4	[redacted]	Miles
93	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 1	2023	$	[redacted]	Class 4	[redacted]	Miles
94	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 6	2023	$	[redacted]	Class 4	[redacted]	Miles
95	Age & Condition	Circuit Rebuilds	MOORESVILLE NO. 3	2023	$	[redacted]	Class 4	[redacted]	Miles
96	Age & Condition	Circuit Rebuilds	NORTH NO. 4	2023	$	[redacted]	Class 4	[redacted]	Miles
97	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 6	2023	$	[redacted]	Class 4	[redacted]	Miles
98	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 11	2023	$	[redacted]	Class 4	[redacted]	Miles
99	Age & Condition	Circuit Rebuilds	NORTHEAST NO. 14	2023	$	[redacted]	Class 4	[redacted]	Miles
100	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 8	2023	$	[redacted]	Class 4	[redacted]	Miles
101	Age & Condition	Circuit Rebuilds	PARK FLETCHER NO. 3	2023	$	[redacted]	Class 4	[redacted]	Miles
102	Age & Condition	Circuit Rebuilds	PARK FLETCHER NO. 7	2023	$	[redacted]	Class 4	[redacted]	Miles
103	Age & Condition	Circuit Rebuilds	PARKER NO. 1	2023	$	[redacted]	Class 4	[redacted]	Miles
104	Age & Condition	Circuit Rebuilds	PIKE NO. 6	2023	$	[redacted]	Class 4	[redacted]	Miles
105	Age & Condition	Circuit Rebuilds	POST RD NO. 5	2023	$	[redacted]	Class 4	[redacted]	Miles
106	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 3	2023	$	[redacted]	Class 4	[redacted]	Miles
107	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 6	2023	$	[redacted]	Class 4	[redacted]	Miles
108	Age & Condition	Circuit Rebuilds	SHEFFIELD NO. 1	2023	$	[redacted]	Class 4	[redacted]	Miles
109	Age & Condition	Circuit Rebuilds	SOUTH NO. 7	2023	$	[redacted]	Class 4	[redacted]	Miles
110	Age & Condition	Circuit Rebuilds	SOUTH NO. 8	2023	$	[redacted]	Class 4	[redacted]	Miles
111	Age & Condition	Circuit Rebuilds	SOUTHEAST NO. 5	2023	$	[redacted]	Class 4	[redacted]	Miles
112	Age & Condition	Circuit Rebuilds	SOUTHPORT NO. 1	2023	$	[redacted]	Class 4	[redacted]	Miles
113	Age & Condition	Circuit Rebuilds	SOUTHPORT NO. 3	2023	$	[redacted]	Class 4	[redacted]	Miles
114	Age & Condition	Circuit Rebuilds	SOUTHPORT NO. 7	2023	$	[redacted]	Class 4	[redacted]	Miles
115	Age & Condition	Circuit Rebuilds	THOMPSON NO. 6	2023	$	[redacted]	Class 4	[redacted]	Miles
116	Age & Condition	Circuit Rebuilds	TOBEY NO. 1	2023	$	[redacted]	Class 4	[redacted]	Miles
117	Age & Condition	Circuit Rebuilds	TREMONT NO. 3	2023	$	[redacted]	Class 4	[redacted]	Miles
118	Age & Condition	Circuit Rebuilds	TREMONT NO. 5	2023	$	[redacted]	Class 4	[redacted]	Miles
119	Age & Condition	Circuit Rebuilds	WEST NO. 4	2023	$	[redacted]	Class 4	[redacted]	Miles
120	Age & Condition	Circuit Rebuilds	WEST NO. 8	2023	$	[redacted]	Class 4	[redacted]	Miles

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
121	Age & Condition	Circuit Rebuilds	WESTLANE NO. 3	2023	$ [redacted]	Class 4	[redacted]	Miles
		Circuit Rebuilds Total			$ 52,812,143		[redacted]	
249	Age & Condition	Substation Assets Replacements	GUION	2023	$ [redacted]	Class 4	[redacted]	Units
250	Age & Condition	Substation Assets Replacements	LAWRENCE	2023	$ [redacted]	Class 4	[redacted]	Units
251	Age & Condition	Substation Assets Replacements	PARKER	2023	$ [redacted]	Class 4	[redacted]	Units
252	Age & Condition	Substation Assets Replacements	SOUTHPORT	2023	$ [redacted]	Class 4	[redacted]	Units
253	Age & Condition	Substation Assets Replacements	SUNNYSIDE	2023	$ [redacted]	Class 4	[redacted]	Units
254	Age & Condition	Substation Assets Replacements	WEST	2023	$ [redacted]	Class 4	[redacted]	Units
		Substation Assets Replacements Total			$ 39,220,541		[redacted]	
275	Age & Condition	XLPE Cable Replacement	XLPE Cable Replacements - 2023	2023	$ [redacted]	Class 4	[redacted]	Feet
		XLPE Cable Replacement Total			$ 12,354,210		[redacted]	
296	Age & Condition	4 kV Conversion	CONVERT HEMLOCK TIE	2023	$ [redacted]	Class 4	[redacted]	Units
297	Age & Condition	4 kV Conversion	CONVERT COLUMBIA	2023	$ [redacted]	Class 4	[redacted]	Units
298	Age & Condition	4 kV Conversion	CONVERT McPHERSON TIE	2023	$ [redacted]	Class 4	[redacted]	Units
299	Age & Condition	4 kV Conversion	CONVERT RUCKLE TIE	2023	$ [redacted]	Class 4	[redacted]	Units
300	Age & Condition	4 kV Conversion	CONVERT COLLEGE	2023	$ [redacted]	Class 4	[redacted]	Units
301	Age & Condition	4 kV Conversion	CONVERT WATSON	2023	$ [redacted]	Class 4	[redacted]	Units
302	Age & Condition	4 kV Conversion	CONVERT 36th ST TIE	2023	$ [redacted]	Class 4	[redacted]	Units
		4 kV Conversion Total			$ 15,541,783		[redacted]	
346	Age & Condition	Tap Reliability Improvement Projects	TRIP - 2023	2023	$ [redacted]	Class 4	[redacted]	Units
		Tap Reliability Improvement Projects Total			$ 10,824,322		[redacted]	
353	Age & Condition	Meter Replacement	Meter Replacement - 2023	2023	$ [redacted]	Class 4	[redacted]	Meters
		Meter Replacement Total			$ 11,392,783		[redacted]	
410	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M54-01	2023	$ [redacted]	Class 4	[redacted]	Units
411	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M54-02	2023	$ [redacted]	Class 4	[redacted]	Units
412	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M45-02	2023	$ [redacted]	Class 4	[redacted]	Units
413	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M45-99	2023	$ [redacted]	Class 4	[redacted]	Units
414	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M45-03	2023	$ [redacted]	Class 4	[redacted]	Units
415	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M54-97	2023	$ [redacted]	Class 4	[redacted]	Units
416	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M55-08	2023	$ [redacted]	Class 4	[redacted]	Units
417	Age & Condition	CBD Secondary Network Upgrades	Duct Line (300 ft.) Location (vic. Michigan St. and Mass. Ave.)	2023	$ [redacted]	Class 4	[redacted]	Units
418	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 108 E. Maryland, UG412	2023	$ [redacted]	Class 4	[redacted]	Units
419	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 215 W. New York, UG411	2023	$ [redacted]	Class 4	[redacted]	Units
420	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 535 Mass. Ave., UG422	2023	$ [redacted]	Class 4	[redacted]	Units
421	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG432 227 E. Market	2023	$ [redacted]	Class 4	[redacted]	Units
422	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG412 108 E. Maryland	2023	$ [redacted]	Class 4	[redacted]	Units
423	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG411 215 W. New York	2023	$ [redacted]	Class 4	[redacted]	Units
424	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG442 2 W. Washington	2023	$ [redacted]	Class 4	[redacted]	Units
425	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG432 126 E. Market	2023	$ [redacted]	Class 4	[redacted]	Units

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	(A)	(B)	(C)	(D)		(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year		Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
426	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG611 301 W. Maryland	2023	$	[redacted]	Class 4	[redacted]	Units
427	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 686 ft) MH M54-00 to MH M54-02	2023	$	[redacted]	Class 4	[redacted]	Units
428	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 828 ft) MH M54-00 to MH M54-03	2023	$	[redacted]	Class 4	[redacted]	Units
429	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 914 ft) MH M45-03 to MH M45-99	2023	$	[redacted]	Class 4	[redacted]	Units
430	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Circuit 641 (Length 1,988 ft)	2023	$	[redacted]	Class 4	[redacted]	Units
431	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Edison Circuit 463 (Length 4,023 ft)	2023	$	[redacted]	Class 4	[redacted]	Units
432	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable with Manholes (1307 ft.) MH in Year	2023	$	[redacted]	Class 4	[redacted]	Units
433	Age & Condition	CBD Secondary Network Upgrades	Real Time DTS Monitoring (vic. Indiana Ave. network Quadrant)	2023	$	[redacted]	Class 4	[redacted]	Units
434	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 321 W. New York, 215 W. New York	2023	$	[redacted]	Class 4	[redacted]	Units
435	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 229 W. Michigan, 210 W. North	2023	$	[redacted]	Class 4	[redacted]	Units
436	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 212 W. Michigan, 139 W. Vermont, 143 N. Illinois	2023	$	[redacted]	Class 4	[redacted]	Units
437	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 651 N. Pierson, 427 N. Illinois, 315 N. Pierson	2023	$	[redacted]	Class 4	[redacted]	Units
		CBD Secondary Network Upgrades Total			$	5,858,219		[redacted]	
522	Age & Condition	Static Wire Performance Improvement	132-46 Sunnyside - Geist	2023	$	[redacted]	Class 4	[redacted]	Miles
523	Age & Condition	Static Wire Performance Improvement	132-51 German Church - Cumberland	2023	$	[redacted]	Class 4	[redacted]	Miles
524	Age & Condition	Static Wire Performance Improvement	132-43 Guion - Crestview	2023	$	[redacted]	Class 4	[redacted]	Miles
		Static Wire Performance Improvement Total			$	11,200,958		[redacted]	
558	Age & Condition	Remote End - Breaker Relay/Upgrades	METHODIST HOSPITAL-3131-1 BKR - Relay	2023	$	[redacted]	Class 4	[redacted]	Units
559	Age & Condition	Remote End - Breaker Relay/Upgrades	ALLISON #3-451-1 BREAKER - Breaker	2023	$	[redacted]	Class 4	[redacted]	Units
560	Age & Condition	Remote End - Breaker Relay/Upgrades	SUNNYSIDE-132-46 BKR - Breaker	2023	$	[redacted]	Class 4	[redacted]	Units
		Remote End - Breaker Relay/Upgrades Total			$	1,608,007		[redacted]	
596	Age & Condition	Pole Replacements	Pole Replacement - 2023	2023	$	[redacted]	Class 4	[redacted]	Poles
597	Age & Condition	Pole Replacements	Pole Treatment - 2023	2023	$	[redacted]	Class 4	[redacted]	Poles
		Pole Replacements Total			$	3,455,435		[redacted]	
607	Age & Condition	Steel Tower Life Extension	Steel Tower Life Extension - 2023	2023	$	[redacted]	Class 4	[redacted]	Structures
		Steel Tower Life Extension Total			$	850,752		[redacted]	
611	Deliverability	Distribution Automation	Reclosers - 2023	2023	$	[redacted]	Class 4	[redacted]	Reclosers
		Distribution Automation Total			$	13,916,985		[redacted]	
622	Deliverability	Substation Design Upgrades	Guion - 345/138kv Auto Xfmr Ring Bus	2023	$	[redacted]	Class 4	[redacted]	Units
623	Deliverability	Substation Design Upgrades	New Retail Substation	2023	$	[redacted]	Class 4	[redacted]	Units
624	Deliverability	Substation Design Upgrades	Northwest Control House	2023	$	[redacted]	Class 4	[redacted]	Units
		Substation Design Upgrades Total			$	32,905,072		[redacted]	
		Grand Total			$	211,971,249			

Indianapolis Power & Light Company
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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	**Age & Condition or Deliverability**	**Project Type**	**project**	**Year**	**Plan Project Cost (Capital Dollars)**	**AACE Cost Estimate**	**Quantity**	**Units**
122	Age & Condition	Circuit Rebuilds	CENTER NO. 9	2024	$ [redacted]	Class 4	[redacted]	Miles
123	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 2	2024	$ [redacted]	Class 4	[redacted]	Miles
124	Age & Condition	Circuit Rebuilds	CUMBERLAND NO. 2	2024	$ [redacted]	Class 4	[redacted]	Miles
125	Age & Condition	Circuit Rebuilds	CUMBERLAND NO. 6	2024	$ [redacted]	Class 4	[redacted]	Miles
126	Age & Condition	Circuit Rebuilds	EAST NO. 9	2024	$ [redacted]	Class 4	[redacted]	Miles
127	Age & Condition	Circuit Rebuilds	GEIST NO. 4	2024	$ [redacted]	Class 4	[redacted]	Miles
128	Age & Condition	Circuit Rebuilds	GERMAN CHURCH NO. 8	2024	$ [redacted]	Class 4	[redacted]	Miles
129	Age & Condition	Circuit Rebuilds	NORTH NO. 3	2024	$ [redacted]	Class 4	[redacted]	Miles
130	Age & Condition	Circuit Rebuilds	PARK FLETCHER NO. 1	2024	$ [redacted]	Class 4	[redacted]	Miles
131	Age & Condition	Circuit Rebuilds	PARK FLETCHER NO. 2	2024	$ [redacted]	Class 4	[redacted]	Miles
132	Age & Condition	Circuit Rebuilds	PARK FLETCHER NO. 6	2024	$ [redacted]	Class 4	[redacted]	Miles
133	Age & Condition	Circuit Rebuilds	PARKER NO. 7	2024	$ [redacted]	Class 4	[redacted]	Miles
134	Age & Condition	Circuit Rebuilds	PROSPECT NO. 1	2024	$ [redacted]	Class 4	[redacted]	Miles
135	Age & Condition	Circuit Rebuilds	QUEMETCO NO. 2	2024	$ [redacted]	Class 4	[redacted]	Miles
136	Age & Condition	Circuit Rebuilds	ROCKVILLE NO. 5	2024	$ [redacted]	Class 4	[redacted]	Miles
137	Age & Condition	Circuit Rebuilds	SHEFFIELD NO. 9	2024	$ [redacted]	Class 4	[redacted]	Miles
138	Age & Condition	Circuit Rebuilds	SHEFFIELD NO. 10	2024	$ [redacted]	Class 4	[redacted]	Miles
139	Age & Condition	Circuit Rebuilds	SOUTH NO. 3	2024	$ [redacted]	Class 4	[redacted]	Miles
140	Age & Condition	Circuit Rebuilds	SOUTHEAST NO. 1	2024	$ [redacted]	Class 4	[redacted]	Miles
141	Age & Condition	Circuit Rebuilds	SOUTHEAST NO. 7	2024	$ [redacted]	Class 4	[redacted]	Miles
142	Age & Condition	Circuit Rebuilds	SOUTHPORT NO. 2	2024	$ [redacted]	Class 4	[redacted]	Miles
143	Age & Condition	Circuit Rebuilds	SOUTHPORT NO. 4	2024	$ [redacted]	Class 4	[redacted]	Miles
144	Age & Condition	Circuit Rebuilds	SOUTHPORT NO. 8	2024	$ [redacted]	Class 4	[redacted]	Miles
145	Age & Condition	Circuit Rebuilds	SOUTHWEST NO. 3	2024	$ [redacted]	Class 4	[redacted]	Miles
146	Age & Condition	Circuit Rebuilds	TOBEY NO. 6	2024	$ [redacted]	Class 4	[redacted]	Miles
147	Age & Condition	Circuit Rebuilds	WESTLANE NO. 4	2024	$ [redacted]	Class 4	[redacted]	Miles
148	Age & Condition	Circuit Rebuilds	WILLIAMS NO. 1	2024	$ [redacted]	Class 4	[redacted]	Miles
149	Age & Condition	Circuit Rebuilds	WILLIAMS NO. 4	2024	$ [redacted]	Class 4	[redacted]	Miles
		Circuit Rebuilds Total			$ 47,773,667			
255	Age & Condition	Substation Assets Replacements	ALLISON #3	2024	$ [redacted]	Class 4	[redacted]	Units
256	Age & Condition	Substation Assets Replacements	MAYWOOD	2024	$ [redacted]	Class 4	[redacted]	Units
257	Age & Condition	Substation Assets Replacements	MILL STREET	2024	$ [redacted]	Class 4	[redacted]	Units
258	Age & Condition	Substation Assets Replacements	SOUTHWEST	2024	$ [redacted]	Class 4	[redacted]	Units
		Substation Assets Replacements Total			$ 34,451,705			
276	Age & Condition	XLPE Cable Replacement	XLPE Cable Replacements - 2024	2024	$ [redacted]	Class 4	[redacted]	Feet
		XLPE Cable Replacement Total			$ 12,297,234			
303	Age & Condition	4 kV Conversion	CONVERT 32nd ST TIE	2024	$ [redacted]	Class 4	[redacted]	Units
304	Age & Condition	4 kV Conversion	CONVERT CROWN HILL	2024	$ [redacted]	Class 4	[redacted]	Units
305	Age & Condition	4 kV Conversion	CONVERT SALEM	2024	$ [redacted]	Class 4	[redacted]	Units

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	(A)	(B)	(C)	(D)	(E)		(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)		AACE Cost Estimate	Quantity	Units
305	Age & Condition	4 kV Conversion	CONVERT SUMMIT	2024	$	[redacted]	Class 4	[redacted]	Units
307	Age & Condition	4 kV Conversion	CONVERT 33rd ST TIE	2024	$	[redacted]	Class 4	[redacted]	Units
308	Age & Condition	4 kV Conversion	CONVERT COOP	2024	$	[redacted]	Class 4	[redacted]	Units
309	Age & Condition	4 kV Conversion	CONVERT TRENTON	2024	$	[redacted]	Class 4	[redacted]	Units
310	Age & Condition	4 kV Conversion	CONVERT ETHYL	2024	$	[redacted]	Class 4	[redacted]	Units
311	Age & Condition	4 kV Conversion	CONVERT TALBOTT	2024	$	[redacted]	Class 4	[redacted]	Units
		4 kV Conversion Total			$	7,583,329			
342	Age & Condition	Tap Reliability Improvement Projects	TRIP - 2024	2024	$	[redacted]	Class 4	[redacted]	Units
		Tap Reliability Improvement Projects Total			$	11,040,808			
354	Age & Condition	Meter Replacement	Meter Replacement - 2024	2024	$	[redacted]	Class 4	[redacted]	Meters
		Meter Replacement Total			$	11,620,639			
438	Age & Condition	CBD Secondary Network Upgrades	New Pre-Cast Manhole (Location vic. Michigan and Pennsylvania)	2024	$	[redacted]	Class 4	[redacted]	Units
439	Age & Condition	CBD Secondary Network Upgrades	New Pre-Cast Manhole (Location vic. 420 N. Pennsylvania)	2024	$	[redacted]	Class 4	[redacted]	Units
440	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH I35-03	2024	$	[redacted]	Class 4	[redacted]	Units
441	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M34-08	2024	$	[redacted]	Class 4	[redacted]	Units
442	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M34-09	2024	$	[redacted]	Class 4	[redacted]	Units
443	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M44-19	2024	$	[redacted]	Class 4	[redacted]	Units
444	Age & Condition	CBD Secondary Network Upgrades	Duct Line WR1 (200 ft.) (vic. Alabama and Mass. Ave.)	2024	$	[redacted]	Class 4	[redacted]	Units
445	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 326 E. New York, UG442	2024	$	[redacted]	Class 4	[redacted]	Units
446	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 117 E. Michigan, UG431	2024	$	[redacted]	Class 4	[redacted]	Units
447	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 150 E. Market, UG442	2024	$	[redacted]	Class 4	[redacted]	Units
448	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG652 120 W. Washington	2024	$	[redacted]	Class 4	[redacted]	Units
449	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG442 326 E. New York	2024	$	[redacted]	Class 4	[redacted]	Units
450	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG411 119 E. Vermont	2024	$	[redacted]	Class 4	[redacted]	Units
451	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG422 227 E. Market	2024	$	[redacted]	Class 4	[redacted]	Units
452	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG442 19 N. Meridian	2024	$	[redacted]	Class 4	[redacted]	Units
453	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG442 121 Monument Circle	2024	$	[redacted]	Class 4	[redacted]	Units
454	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 153 ft) MH M34-08 to MH M44-13	2024	$	[redacted]	Class 4	[redacted]	Units
455	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 97 ft) MH M34-09 to MH M34-08	2024	$	[redacted]	Class 4	[redacted]	Units
456	Age & Condition	CBD Secondary Network Upgrades	Replace Secondary Cable (Length 216 ft) MH M34-08 to MH M44-18	2024	$	[redacted]	Class 4	[redacted]	Units
457	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cicuit 642 (Length 1116 ft)	2024	$	[redacted]	Class 4	[redacted]	Units
458	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cicuit 641 (Length 3357 ft)	2024	$	[redacted]	Class 4	[redacted]	Units
459	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable with Manholes (300 ft.) MH in Year	2024	$	[redacted]	Class 4	[redacted]	Units
460	Age & Condition	CBD Secondary Network Upgrades	Real Time DAS Monitoring (Gardner Ln. north Quadrant)	2024	$	[redacted]	Class 4	[redacted]	Units
461	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 28 W. Michigan, 602 N. Alabama	2024	$	[redacted]	Class 4	[redacted]	Units
462	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 529 N. Ogden, 535 N. New Jersey	2024	$	[redacted]	Class 4	[redacted]	Units
463	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 535 Mass. Ave., 428 Mass. Ave., 390 Mass. Ave.	2024	$	[redacted]	Class 4	[redacted]	Units
464	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 333 Mass. Ave., 326 E. New York, 425 E. Vermont	2024	$	[redacted]	Class 4	[redacted]	Units
		CBD Secondary Network Upgrades Total			$	5,001,613			

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	(A)	(B)	(C)	(D)	(E)		(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)		AACE Cost Estimate	Quantity	Units
525	Age & Condition	Static Wire Performance Improvement	132-57 North - River Road	2024	$	[redacted]	Class 4	[redacted]	Miles
526	Age & Condition	Static Wire Performance Improvement	132-55 Castleton - River Road	2024	$	[redacted]	Class 4	[redacted]	Miles
527	Age & Condition	Static Wire Performance Improvement	132-52 Cumberland - Ford	2024	$	[redacted]	Class 4	[redacted]	Miles
528	Age & Condition	Static Wire Performance Improvement	132-50 German Church - Sunnyside	2024	$	[redacted]	Class 4	[redacted]	Miles
		Static Wire Performance Improvement Total			$	11,497,320		[redacted]	
561	Age & Condition	Remote End - Breaker Relay/Upgrades	NORTH-132-71-86 TIE BKR (7) - Relay	2024	$	[redacted]	Class 4	[redacted]	Units
562	Age & Condition	Remote End - Breaker Relay/Upgrades	CRESTVIEW-138KV BUS TIE BKR - Relay	2024	$	[redacted]	Class 4	[redacted]	Units
563	Age & Condition	Remote End - Breaker Relay/Upgrades	SANITATION BLMT-138 BUSTIE OCB - Relay	2024	$	[redacted]	Class 4	[redacted]	Units
564	Age & Condition	Remote End - Breaker Relay/Upgrades	CASTLETON-132-66 BKR - Relay	2024	$	[redacted]	Class 4	[redacted]	Units
565	Age & Condition	Remote End - Breaker Relay/Upgrades	LAWRENCE-132-45 BREAKER - Relay	2024	$	[redacted]	Class 4	[redacted]	Units
566	Age & Condition	Remote End - Breaker Relay/Upgrades	ST GT YD-132-02 BKR - Relay	2024	$	[redacted]	Class 4	[redacted]	Units
567	Age & Condition	Remote End - Breaker Relay/Upgrades	IU CAMPUS N-437-1 BKR - Relay	2024	$	[redacted]	Class 4	[redacted]	Units
568	Age & Condition	Remote End - Breaker Relay/Upgrades	PERRY K-34.5KV 2839-1 BKR - Relay	2024	$	[redacted]	Class 4	[redacted]	Units
569	Age & Condition	Remote End - Breaker Relay/Upgrades	IU CAMPUS W-391-1 BKR - Relay	2024	$	[redacted]	Class 4	[redacted]	Units
570	Age & Condition	Remote End - Breaker Relay/Upgrades	BROOKWOOD-1571-5 BKR - Breaker & Relay	2024	$	[redacted]	Class 4	[redacted]	Units
571	Age & Condition	Remote End - Breaker Relay/Upgrades	BROOKWOOD-132-36 BKR - Breaker	2024	$	[redacted]	Class 4	[redacted]	Units
572	Age & Condition	Remote End - Breaker Relay/Upgrades	NORTHWEST-132-04 BKR - Breaker & Relay	2024	$	[redacted]	Class 4	[redacted]	Units
573	Age & Condition	Remote End - Breaker Relay/Upgrades	NORTHWEST-132-39 BKR - Breaker & Relay	2024	$	[redacted]	Class 4	[redacted]	Units
		Remote End - Breaker Relay/Upgrades Total			$	6,234,867		[redacted]	
598	Age & Condition	Pole Replacements	Pole Replacement - 2024	2024	$	[redacted]	Class 4	[redacted]	Poles
599	Age & Condition	Pole Replacements	Pole Treatment - 2024	2024	$	[redacted]	Class 4	[redacted]	Poles
		Pole Replacements Total			$	3,524,544		[redacted]	
612	Deliverability	Distribution Automation	Reclosers - 2024	2024	$	[redacted]	Class 4	[redacted]	Reclosers
		Distribution Automation Total			$	14,195,325		[redacted]	
625	Deliverability	Substation Design Upgrades	Stout Sub - Add Breaker & Create Ring Bus	2024	$	[redacted]	Class 4	[redacted]	Units
626	Deliverability	Substation Design Upgrades	Southwest Control House	2024	$	[redacted]	Class 4	[redacted]	Units
		Substation Design Upgrades Total			$	6,323,236			
		Grand Total			$	171,544,287			

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	**Age & Condition or Deliverability**	**Project Type**	**project**	**Year**	**Plan Project Cost (Capital Dollars)**	**AACE Cost Estimate**	**Quantity**	**Units**
150	Age & Condition	Circuit Rebuilds	BROOKWOOD NO. 6	2025	$ [redacted]	Class 4	[redacted]	Miles
151	Age & Condition	Circuit Rebuilds	BROOKWOOD NO. 8	2025	$ [redacted]	Class 4	[redacted]	Miles
152	Age & Condition	Circuit Rebuilds	CASTLETON NO. 9	2025	$ [redacted]	Class 4	[redacted]	Miles
153	Age & Condition	Circuit Rebuilds	CENTER NO. 5	2025	$ [redacted]	Class 4	[redacted]	Miles
154	Age & Condition	Circuit Rebuilds	CRAWFORDSVILLE NO. 1	2025	$ [redacted]	Class 4	[redacted]	Miles
155	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 5	2025	$ [redacted]	Class 4	[redacted]	Miles
156	Age & Condition	Circuit Rebuilds	CRESTVIEW NO. 7	2025	$ [redacted]	Class 4	[redacted]	Miles
157	Age & Condition	Circuit Rebuilds	EAST NO. 2	2025	$ [redacted]	Class 4	[redacted]	Miles
158	Age & Condition	Circuit Rebuilds	GERMAN CHURCH NO. 5	2025	$ [redacted]	Class 4	[redacted]	Miles
159	Age & Condition	Circuit Rebuilds	GLENNS VALLEY NO. 8	2025	$ [redacted]	Class 4	[redacted]	Miles
160	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 7	2025	$ [redacted]	Class 4	[redacted]	Miles
161	Age & Condition	Circuit Rebuilds	MILL ST. NO. 6	2025	$ [redacted]	Class 4	[redacted]	Miles
162	Age & Condition	Circuit Rebuilds	MILL ST. NO. 10	2025	$ [redacted]	Class 4	[redacted]	Miles
163	Age & Condition	Circuit Rebuilds	PROSPECT NO. 3	2025	$ [redacted]	Class 4	[redacted]	Miles
164	Age & Condition	Circuit Rebuilds	SHEFFIELD NO. 8	2025	$ [redacted]	Class 4	[redacted]	Miles
165	Age & Condition	Circuit Rebuilds	SOUTH NO. 1	2025	$ [redacted]	Class 4	[redacted]	Miles
166	Age & Condition	Circuit Rebuilds	SOUTHEAST NO. 10	2025	$ [redacted]	Class 4	[redacted]	Miles
167	Age & Condition	Circuit Rebuilds	TOBEY NO. 3	2025	$ [redacted]	Class 4	[redacted]	Miles
168	Age & Condition	Circuit Rebuilds	WEST NO. 5	2025	$ [redacted]	Class 4	[redacted]	Miles
169	Age & Condition	Circuit Rebuilds	WESTLANE NO. 2	2025	$ [redacted]	Class 4	[redacted]	Miles
170	Age & Condition	Circuit Rebuilds	WESTLANE NO. 9	2025	$ [redacted]	Class 4	[redacted]	Miles
171	Age & Condition	Circuit Rebuilds	WILLIAMS NO. 6	2025	$ [redacted]	Class 4	[redacted]	Miles
		Circuit Rebuilds Total			$ 49,882,752		[redacted]	
259	Age & Condition	Substation Assets Replacements	EAST	2025	$ [redacted]	Class 4	[redacted]	Units
260	Age & Condition	Substation Assets Replacements	NAVAL AVIONICS	2025	$ [redacted]	Class 4	[redacted]	Units
261	Age & Condition	Substation Assets Replacements	NORTHWEST	2025	$ [redacted]	Class 4	[redacted]	Units
262	Age & Condition	Substation Assets Replacements	SOUTH	2025	$ [redacted]	Class 4	[redacted]	Units
263	Age & Condition	Substation Assets Replacements	SOUTHEAST	2025	$ [redacted]	Class 4	[redacted]	Units
		Substation Assets Replacements Total			$ 44,283,282		[redacted]	
277	Age & Condition	XLPE Cable Replacement	**XLPE Cable Replacements - 2025**	2025	$ [redacted]	Class 4	[redacted]	Feet
		XLPE Cable Replacement Total			$ 12,829,535		[redacted]	
312	Age & Condition	4 kV Conversion	CONVERT BECKWITH	2025	$ [redacted]	Class 4	[redacted]	Units
313	Age & Condition	4 kV Conversion	CONVERT CORNELL	2025	$ [redacted]	Class 4	[redacted]	Units
314	Age & Condition	4 kV Conversion	CONVERT ALVORD	2025	$ [redacted]	Class 4	[redacted]	Units
315	Age & Condition	4 kV Conversion	CONVERT INDUSTRIAL CENTER	2025	$ [redacted]	Class 4	[redacted]	Units
316	Age & Condition	4 kV Conversion	CONVERT MANLOVE	2025	$ [redacted]	Class 4	[redacted]	Units
317	Age & Condition	4 kV Conversion	CONVERT ROOSEVELT	2025	$ [redacted]	Class 4	[redacted]	Units
		4 kV Conversion Total			$ 12,385,359		[redacted]	
348	Age & Condition	Tap Reliability Improvement Projects	TRIP - 2025	2025	$ [redacted]	Class 4	[redacted]	Units

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
		Tap Reliability Improvement Projects Total			$ 11,261,624		[redacted]	
465	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M44-12	2025	$ [redacted]	Class 4	[redacted]	Units
466	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M44-10	2025	$ [redacted]	Class 4	[redacted]	Units
467	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M44-08	2025	$ [redacted]	Class 4	[redacted]	Units
468	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M44-07	2025	$ [redacted]	Class 4	[redacted]	Units
469	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M44-04	2025	$ [redacted]	Class 4	[redacted]	Units
470	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M44-98	2025	$ [redacted]	Class 4	[redacted]	Units
471	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M55-98	2025	$ [redacted]	Class 4	[redacted]	Units
472	Age & Condition	CBD Secondary Network Upgrades	Duct Line WR1 (200 ft.) (vic. New Jersey and Mass. Ave.)	2025	$ [redacted]	Class 4	[redacted]	Units
473	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 403 N. Pierson, UG441	2025	$ [redacted]	Class 4	[redacted]	Units
474	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 403 N. Pierson, UG451	2025	$ [redacted]	Class 4	[redacted]	Units
475	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 110 N. Scioto, UG422	2025	$ [redacted]	Class 4	[redacted]	Units
476	Age & Condition	CBD Secondary Network Upgrades	Rpl Network Transf. 120/208, UG651 60 W. Maryland	2025	$ [redacted]	Class 4	[redacted]	Units
477	Age & Condition	CBD Secondary Network Upgrades	Rpl Network Transf. 277/480, UG432 19 N. Meridian	2025	$ [redacted]	Class 4	[redacted]	Units
478	Age & Condition	CBD Secondary Network Upgrades	Rpl Network Transf 277/480, UG611 25 W. Georgia	2025	$ [redacted]	Class 4	[redacted]	Units
479	Age & Condition	CBD Secondary Network Upgrades	Rpl Network Transf. 277/480, UG641 21 S. Capital	2025	$ [redacted]	Class 4	[redacted]	Units
480	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cicuit 633 (Length 4266 ft)	2025	$ [redacted]	Class 4	[redacted]	Units
481	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cicuit 611 (Length 2535 ft)	2025	$ [redacted]	Class 4	[redacted]	Units
482	Age & Condition	CBD Secondary Network Upgrades	Real Time DAS Monitoring (Edison East Quadrant)	2025	$ [redacted]	Class 4	[redacted]	Units
483	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 115 E. Market, 117 N. Pennsylvania	2025	$ [redacted]	Class 4	[redacted]	Units
484	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 150 E. Market, 227 E. Market, 132 E. Washington	2025	$ [redacted]	Class 4	[redacted]	Units
485	Age & Condition	CBD Secondary Network Upgrades	Vault Technology 129 E. Washington, 21 Virginia Ave., 133 S. Delaware	2025	$ [redacted]	Class 4	[redacted]	Units
		CBD Secondary Network Upgrades Total			$ 5,892,283		[redacted]	
529	Age & Condition	Static Wire Performance Improvement	132-38 Brookwood - Lawrence	2025	$ [redacted]	Class 4	[redacted]	Miles
530	Age & Condition	Static Wire Performance Improvement	132-49 East - Tobey	2025	$ [redacted]	Class 4	[redacted]	Miles
531	Age & Condition	Static Wire Performance Improvement	132-68 Tobey - German Church	2025	$ [redacted]	Class 4	[redacted]	Miles
532	Age & Condition	Static Wire Performance Improvement	132-32 Mill Street - Edison	2025	$ [redacted]	Class 4	[redacted]	Miles
		Static Wire Performance Improvement Total			$ 10,679,473		[redacted]	
574	Age & Condition	Remote End - Breaker Relay/Upgrades	CRAWFORDSVILLE RD.-132-35 BKR - Relay	2025	$ [redacted]	Class 4	[redacted]	Units
575	Age & Condition	Remote End - Breaker Relay/Upgrades	WILLIAMS ST-132-75 BREAKER - Relay	2025	$ [redacted]	Class 4	[redacted]	Units
576	Age & Condition	Remote End - Breaker Relay/Upgrades	LILLY CORP-4151-3 BKR - Relay	2025	$ [redacted]	Class 4	[redacted]	Units
577	Age & Condition	Remote End - Breaker Relay/Upgrades	NAVAL AVIONICS-1771-1 - Breaker & Relay	2025	$ [redacted]	Class 4	[redacted]	Units
578	Age & Condition	Remote End - Breaker Relay/Upgrades	MAYWOOD-132-13 BREAKER - Breaker	2025	$ [redacted]	Class 4	[redacted]	Units
579	Age & Condition	Remote End - Breaker Relay/Upgrades	MAYWOOD-132-11 BREAKER - Breaker	2025	$ [redacted]	Class 4	[redacted]	Units
		Remote End - Breaker Relay/Upgrades Total			$ 3,110,142		[redacted]	
600	Age & Condition	Pole Replacements	Pole Replacement - 2025	2025	$ [redacted]	Class 4	[redacted]	Poles
601	Age & Condition	Pole Replacements	Pole Treatment - 2025	2025	$ [redacted]	Class 4	[redacted]	Poles
		Pole Replacements Total			$ 3,595,035		[redacted]	
613	Deliverability	Distribution Automation	Reclosers - 2025	2025	$ [redacted]	Class 4	[redacted]	Reclosers

Indianapolis Power & Light Company
2025 - TDSIC Project Detail - Capital Dollars Only

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
		Distribution Automation Total			$ 14,479,231			
627	Deliverability	Substation Design Upgrades	New Riverside Sub	2025	$ [redacted]	Class 4	[redacted]	Units
		Substation Design Upgrades Total			$ 16,777,568			
		Grand Total			$ 185,176,284			

Indianapolis Power & Light Company
2026 - TDSIC Project Detail - Capital Dollars Only

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
172	Age & Condition	Circuit Rebuilds	BROOKWOOD NO. 1	2026	$ [redacted]	Class 4	[redacted]	Miles
173	Age & Condition	Circuit Rebuilds	BROOKWOOD NO. 10	2026	$ [redacted]	Class 4	[redacted]	Miles
174	Age & Condition	Circuit Rebuilds	CAMBY NO. 3	2026	$ [redacted]	Class 4	[redacted]	Miles
175	Age & Condition	Circuit Rebuilds	CAMBY NO. 6	2026	$ [redacted]	Class 4	[redacted]	Miles
176	Age & Condition	Circuit Rebuilds	CENTER NO. 1	2026	$ [redacted]	Class 4	[redacted]	Miles
177	Age & Condition	Circuit Rebuilds	CENTER NO. 2	2026	$ [redacted]	Class 4	[redacted]	Miles
178	Age & Condition	Circuit Rebuilds	EDGEWOOD NO. 3	2026	$ [redacted]	Class 4	[redacted]	Miles
179	Age & Condition	Circuit Rebuilds	GUION NO. 8	2026	$ [redacted]	Class 4	[redacted]	Miles
180	Age & Condition	Circuit Rebuilds	INDIAN CREEK NO. 10	2026	$ [redacted]	Class 4	[redacted]	Miles
181	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 2	2026	$ [redacted]	Class 4	[redacted]	Miles
182	Age & Condition	Circuit Rebuilds	LAWRENCE NO. 9	2026	$ [redacted]	Class 4	[redacted]	Miles
183	Age & Condition	Circuit Rebuilds	MILL ST. NO. 8	2026	$ [redacted]	Class 4	[redacted]	Miles
184	Age & Condition	Circuit Rebuilds	MOORESVILLE NO. 2	2026	$ [redacted]	Class 4	[redacted]	Miles
185	Age & Condition	Circuit Rebuilds	NORTH NO. 5	2026	$ [redacted]	Class 4	[redacted]	Miles
186	Age & Condition	Circuit Rebuilds	NORTHWEST NO. 6	2026	$ [redacted]	Class 4	[redacted]	Miles
187	Age & Condition	Circuit Rebuilds	PARKER NO. 4	2026	$ [redacted]	Class 4	[redacted]	Miles
188	Age & Condition	Circuit Rebuilds	POST RD NO. 2	2026	$ [redacted]	Class 4	[redacted]	Miles
189	Age & Condition	Circuit Rebuilds	SOUTH NO. 2	2026	$ [redacted]	Class 4	[redacted]	Miles
190	Age & Condition	Circuit Rebuilds	SOUTH NO. 9	2026	$ [redacted]	Class 4	[redacted]	Miles
191	Age & Condition	Circuit Rebuilds	SOUTHEAST NO. 3	2026	$ [redacted]	Class 4	[redacted]	Miles
192	Age & Condition	Circuit Rebuilds	SOUTHEAST NO. 8	2026	$ [redacted]	Class 4	[redacted]	Miles
193	Age & Condition	Circuit Rebuilds	SOUTHWEST NO. 2	2026	$ [redacted]	Class 4	[redacted]	Miles
194	Age & Condition	Circuit Rebuilds	SOUTHWEST NO. 4	2026	$ [redacted]	Class 4	[redacted]	Miles
195	Age & Condition	Circuit Rebuilds	WEST NO. 6	2026	$ [redacted]	Class 4	[redacted]	Miles
196	Age & Condition	Circuit Rebuilds	WEST NO. 7	2026	$ [redacted]	Class 4	[redacted]	Miles
197	Age & Condition	Circuit Rebuilds	WESTLANE NO. 10	2026	$ [redacted]	Class 4	[redacted]	Miles
198	Age & Condition	Circuit Rebuilds	WILLIAMS NO. 7	2026	$ [redacted]	Class 4	[redacted]	Miles
		Circuit Rebuilds Total			$ 49,913,886		[redacted]	
264	Age & Condition	Substation Assets Replacements	BROOKWOOD	2026	$ [redacted]	Class 4	[redacted]	Units
265	Age & Condition	Substation Assets Replacements	ENGLISH	2026	$ [redacted]	Class 4	[redacted]	Units
266	Age & Condition	Substation Assets Replacements	EVANS MILLING INDUSTRIAL SUB	2026	$ [redacted]	Class 4	[redacted]	Units
267	Age & Condition	Substation Assets Replacements	GLIDDEN	2026	$ [redacted]	Class 4	[redacted]	Units
268	Age & Condition	Substation Assets Replacements	NATIONAL STARCH	2026	$ [redacted]	Class 4	[redacted]	Units
269	Age & Condition	Substation Assets Replacements	NORTH	2026	$ [redacted]	Class 4	[redacted]	Units
270	Age & Condition	Substation Assets Replacements	NORTHEAST	2026	$ [redacted]	Class 4	[redacted]	Units
271	Age & Condition	Substation Assets Replacements	PROSPECT	2026	$ [redacted]	Class 4	[redacted]	Units
		Substation Assets Replacements Total			$ 46,536,273		[redacted]	
278	Age & Condition	XLPE Cable Replacement	XLPE Cable Replacements - 2026	2026	$ [redacted]	Class 4	[redacted]	Feet
		XLPE Cable Replacement Total			$ 12,301,534		[redacted]	

Indianapolis Power & Light Company
2026 - TDSIC Project Detail - Capital Dollars Only

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)	AACE Cost Estimate	Quantity	Units
318	Age & Condition	4 kV Conversion	CONVERT JEFFERSON	2026	$ [redacted]	Class 4	[redacted]	Units
319	Age & Condition	4 kV Conversion	CONVERT LUDLOW	2026	$ [redacted]	Class 4	[redacted]	Units
320	Age & Condition	4 kV Conversion	CONVERT SUTHERLAND	2026	$ [redacted]	Class 4	[redacted]	Units
321	Age & Condition	4 kV Conversion	CONVERT BRIGHT	2026	$ [redacted]	Class 4	[redacted]	Units
322	Age & Condition	4 kV Conversion	CONVERT SCHWITZER NO 1	2026	$ [redacted]	Class 4	[redacted]	Units
323	Age & Condition	4 kV Conversion	CONVERT SCHWITZER NO 2	2026	$ [redacted]	Class 4	[redacted]	Units
		4 kV Conversion Total			$ 7,520,673		[redacted]	
349	Age & Condition	Tap Reliability Improvement Projects	TRIP - 2026	2026	$ [redacted]	Class 4	[redacted]	Units
		Tap Reliability Improvement Projects Total			$ 11,486,857		[redacted]	
486	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M32-14	2026	$ [redacted]	Class 4	[redacted]	Units
487	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M33-94	2026	$ [redacted]	Class 4	[redacted]	Units
488	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M33-95	2026	$ [redacted]	Class 4	[redacted]	Units
489	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M33-08	2026	$ [redacted]	Class 4	[redacted]	Units
490	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M33-06	2026	$ [redacted]	Class 4	[redacted]	Units
491	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M33-05	2026	$ [redacted]	Class 4	[redacted]	Units
492	Age & Condition	CBD Secondary Network Upgrades	Rebuild MH M23-93	2026	$ [redacted]	Class 4	[redacted]	Units
493	Age & Condition	CBD Secondary Network Upgrades	Duct Line (200 ft.) (vic. Delaware and Mass. Ave.)	2026	$ [redacted]	Class 4	[redacted]	Units
494	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 110 N. Scioto, UG432	2026	$ [redacted]	Class 4	[redacted]	Units
495	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 126 E. Market, UG432	2026	$ [redacted]	Class 4	[redacted]	Units
496	Age & Condition	CBD Secondary Network Upgrades	Network Protector Replace 119 E. Vermont, UG411	2026	$ [redacted]	Class 4	[redacted]	Units
497	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG651 21 S. Capital	2026	$ [redacted]	Class 4	[redacted]	Units
498	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG432 30 E. Market	2026	$ [redacted]	Class 4	[redacted]	Units
499	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 120/208, UG633 40 N. Capital	2026	$ [redacted]	Class 4	[redacted]	Units
500	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG412 150 E. Ohio	2026	$ [redacted]	Class 4	[redacted]	Units
501	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG442 225 E. Michigan	2026	$ [redacted]	Class 4	[redacted]	Units
502	Age & Condition	CBD Secondary Network Upgrades	Replace Network Transf. 277/480, UG401 525 N. Pennsylvania	2026	$ [redacted]	Class 4	[redacted]	Units
503	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cicuit 613 (Length 3097 ft)	2026	$ [redacted]	Class 4	[redacted]	Units
504	Age & Condition	CBD Secondary Network Upgrades	Replace Primary Cable Gardner Lane Cicuit 622 (Length 2681 ft)	2026	$ [redacted]	Class 4	[redacted]	Units
505	Age & Condition	CBD Secondary Network Upgrades	Real Time DAS Monitoring (Edison West Quadrant)	2026	$ [redacted]	Class 4	[redacted]	Units
506	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 123 S. Illinois, 33 W. Georgia	2026	$ [redacted]	Class 4	[redacted]	Units
507	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 26 S. Meridian, 38 S. Meridian	2026	$ [redacted]	Class 4	[redacted]	Units
508	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 20 E. Maryland, 30 S. Pennsylvania	2026	$ [redacted]	Class 4	[redacted]	Units
509	Age & Condition	CBD Secondary Network Upgrades	Vault Technology - 30 E. Georgia, 31 E. Georgia, 211 S. Meridian	2026	$ [redacted]	Class 4	[redacted]	Units
		CBD Secondary Network Upgrades Total			$ 6,373,447		[redacted]	
533	Age & Condition	Static Wire Performance Improvement	132-54 Castleton - Geist	2026	$ [redacted]	Class 4	[redacted]	Miles
534	Age & Condition	Static Wire Performance Improvement	132-64 Rockville - Allison #4	2026	$ [redacted]	Class 4	[redacted]	Miles
		Static Wire Performance Improvement Total			$ 7,601,921		[redacted]	
580	Age & Condition	Remote End - Breaker Relay/Upgrades	SOUTHEAST-132-72 BKR - Relay	2026	$ [redacted]	Class 4	[redacted]	Units
581	Age & Condition	Remote End - Breaker Relay/Upgrades	SOUTHEAST-132-18 BKR - Relay	2026	$ [redacted]	Class 4	[redacted]	Units

Indianapolis Power & Light Company
2026 - TDSIC Project Detail - Capital Dollars Only

	(A)	(B)	(C)	(D)	(E)		(F)	(G)	(H)
Line No.	Age & Condition or Deliverability	Project Type	project	Year	Plan Project Cost (Capital Dollars)		AACE Cost Estimate	Quantity	Units
582	Age & Condition	Remote End - Breaker Relay/Upgrades	PROSPECT-1751-1 BREAKER - Breaker	2026	$	[redacted]	Class 4	[redacted]	Units
583	Age & Condition	Remote End - Breaker Relay/Upgrades	IU CAMPUS N-491-3 BKR - Relay	2026	$	[redacted]	Class 4	[redacted]	Units
584	Age & Condition	Remote End - Breaker Relay/Upgrades	IU CAMPUS W-431-3 BKR - Relay	2026	$	[redacted]	Class 4	[redacted]	Units
585	Age & Condition	Remote End - Breaker Relay/Upgrades	EAST-132-07 W BKR - Breaker	2026	$	[redacted]	Class 4	[redacted]	Units
586	Age & Condition	Remote End - Breaker Relay/Upgrades	WEST-132-70W BKR - Breaker	2026	$	[redacted]	Class 4	[redacted]	Units
587	Age & Condition	Remote End - Breaker Relay/Upgrades	WEST-132-06 BKR - Breaker & Relay	2026	$	[redacted]	Class 4	[redacted]	Units
588	Age & Condition	Remote End - Breaker Relay/Upgrades	WEST-132-63 BKR - Breaker	2026	$	[redacted]	Class 4	[redacted]	Units
589	Age & Condition	Remote End - Breaker Relay/Upgrades	EAST-132-07 E BKR - Breaker & Relay	2026	$	[redacted]	Class 4	[redacted]	Units
		Remote End - Breaker Relay/Upgrades Total			$	6,425,834			
602	Age & Condition	Pole Replacements	Pole Replacement - 2026	2026	$	[redacted]	Class 4	[redacted]	Poles
603	Age & Condition	Pole Replacements	Pole Treatment - 2026	2026	$	[redacted]	Class 4	[redacted]	Poles
		Pole Replacements Total			$	3,666,935			
614	Deliverability	Distribution Automation	Reclosers - 2026	2026	$	[redacted]	Class 4	[redacted]	Reclosers
		Distribution Automation Total			$	14,768,816			
638	Deliverability	Substation Design Upgrades	Northeast Control House	2026	$	[redacted]	Class 4	[redacted]	Units
		Substation Design Upgrades Total			$	2,632,615			
		Grand Total			$	169,228,791			

Public Appendix 8.8 Class 2 Estimate Example

Indianapolis Power & Light Company
PROJECT ESTIMATE SUPPLEMENT

PROJECT NAME:	Maywood No 1	Project #	
		WMIS #	517721

MATERIAL

Section	MATERIAL DESCRIPTION	UOM	QTY	UNIT PRICE	TOTAL	
CONTRACTOR MATERIAL & OR PURCHASED EQUIPMENT & MATERIAL						
	Use for contractor supplied material if applicable				0	
					0	
					0	
					0	
					0	
					0	
					0	
					0	
					0	
					0	
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					0	
					0	
					0	
IPL STORES MATERIAL & EQUIP						
	Use for IPL supplied material. Input a single line item total since a WMS material request is already generated.		1	[redacted]		CON
	Transformers	LOT	1			CON
					0	
					0	
					0	
					0	
					0	
					0	
					0	
					0	

LABOR INSTALLATION COSTS

Section	CONTRACTOR NAME OR IPL DEPT.	HOURS	RATE	TOTAL	
CONTRACTOR LABOR					
	Construct labor hours from WMS for overhead labor, include street light labor. $[redacted]per hour includes labor and equipment	1,629.82	[redacted]		CON
	Traffic control crew hours. Construct hours / 5 * $[redacted]	365.96	[redacted]		CON
	Hydrovac - pole count *$[redacted]	37.00	[redacted]		CON
	Hydrovac Misc - add additonal based on job specifics (rate is $[redacted]per hour)	5.00	[redacted]		CON
	Line Clearing - Total cost / [redacted]to get crew hours (crew rate = $[redacted]	534.44	[redacted]		CON
	Engineering design and calc. Hours * $[redacted] Hours to complete IFC + 20%	172.00	[redacted]		CON
	SWPP plan development (flat rate)	1.00	[redacted]		CON
	SWPP management (estimate provided) Total / $[redacted]to get hours	100.00	[redacted]		CON
	Ingress / R/W clearing (total /$[redacted]to get hours)	43.33	[redacted]		CON
	R/W restoration (estimate provided) Total / $[redacted]to get hours. Includes contractor provided material. (backfill dirt)	23.33	[redacted]		CON
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
IPL LABOR					
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
IPL LABOR (ENGINEER & SUPERVISION)					
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	
				0	

TOTAL CONSTRUCTION COSTS

IPL Stores Equip. Material	Use for Cash Flow Wks	[redacted]
Contractor Svcs. Material	Use for Cash Flow Wks	
Contractor Svcs. Labor	Use for Cash Flow Wks	
IPL Labor-Hourly ($)	Use for Cash Flow Wks	
IPL Labor-Salaried ($)	Use for Cash Flow Wks	
Sales Tax	Calc from Cash Flow Wks	
Indirects	Calc from Cash Flow Wks	
AFUDC	Calc from Cash Flow Wks	
CONSTRUCTION TOTAL		
CIAC	Calc from Cash Flow Wks	
NET CAPITAL	Calc from Cash Flow Wks	

TOTAL REMOVAL/SALVAGE COSTS

Contractor Svcs. Material	Use for Cash Flow Wks	$0
Contractor Svcs. Labor	Use for Cash Flow Wks	$0
IPL Labor-Hourly ($)	Use for Cash Flow Wks	$0
IPL Labor-Salaried ($)	Use for Cash Flow Wks	$0
Indirects	Calc from Cash Flow Wks	$0
RETIREMENT TOTAL		$0
SALVAGE/PROCEEDS	Calc from Cash Flow Wks	$0

IPL - An AES Company

ESTIMATE DETAIL SUMMARY Project # WMIS 517721

PROJECT NAME: Maywood No 1

AFUDC Eligible (Y or N) Y

Must be a Capital project, must have a duration of > 30 days, must cost >$1,000

CIAC or Full Bill Projects are Not Eligible for AFUDC

Year 1 2019

CONSTRUCTION COSTS	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IPL Stores Equip. Material					[redacted]								[redacted]
Contractor Svcs. Material													0
Contractor Svcs. Labor					[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
Trans/Dist Lines Physical													0
PD Other Labor													0
Trans Design/Troublemen													0
Sub/Network/Relay-SCADA													0
Sales Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Indirects - A&G, Stores	0	0	0	0	[redacted]	0	0	0	0	0	0	0	[redacted]
AFUDC Debt	0	0	0	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0	0	[redacted]
AFUDC Equity	0	0	0	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0	0	[redacted]
CONSTRUCTION TOTAL	0	0	0	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0	0	[redacted]
CIAC / Full Cost Bill													0

RETIREMENT COSTS	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Contractor Svcs. Labor					0	0	0	0	0	0			0
Trans/Dist Lines Physical													0
PD Other													0
Trans Design/Troublemen													0
Sub/Network/Relay-SCADA													0
Indirects - A&G, Stores	0	0	0	0	0	0	0	0	0	0	0	0	0
RETIREMENT TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0
SALVAGE/PROCEEDS													0
NET CAPITAL COSTS	0	0	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	0	[illegible]

Year 2 2020

CONSTRUCTION COSTS	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IPL Stores Equip. Material													0
Contractor Svcs. Material													0
Contractor Svcs. Labor													0
Trans/Dist Lines Physical													0
PD Other Labor													0
Trans Design/Troublemen													0
Sub/Network/Relay-SCADA													0
Sales Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Indirects - A&G, Stores	0	0	0	0	0	0	0	0	0	0	0	0	0
AFUDC Debt	0	0	0	0	0	0	0	0	0	0	0	0	0
AFUDC Equity	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSTRUCTION TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0
CIAC / Full Cost Bill													0

RETIREMENT COSTS	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Contractor Svcs. Labor													0
Trans/Dist Lines Physical													0
PD Other													0
Trans Design/Troublemen													0
Sub/Network/Relay-SCADA													0
Indirects - A&G, Stores	0	0	0	0	0	0	0	0	0	0	0	0	0
RETIREMENT TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0
SALVAGE/PROCEEDS													0
NET CAPITAL COSTS	0	0	0	0	0	0	0	0	0	0	0	0	0

Expected Annual Cash Outflow	2019	2020
	[redacted]	0
Miss per Cash Flow	0	

Total $ per Construct Cash Flow Estimate [redacted]

Total $ per Retire Cash Flow Estimate 0

TOTAL AFUDC [redacted]
CONSTRUCTION INDIRECTS
RETIREMENT INDIRECTS

Description	Rate	Eff. Date	
Trans/Dist Lines Physical	[redacted]	04/01/15	CC 105
Sub/Network/Relay-SCADA		04/01/18	CC's 103, 124, 129
AFUDC Debt		03/31/19	
AFUDC Equity		03/31/19	
IPL Stores Material Handling		01/01/19	
Benefits & FICA tax		04/01/18	
Travel Time Lines			

	Description	Rate	Eff. Date	
H	Trans Design/Troublemen	[redacted]	04/01/15	CC's 121, 123
I	PD Other		04/01/18	All Other PD CC's
J	Trans Contractor Labor		11/1/2013	Currently No Contractor indirects
K	Sales Tax		4/1/2002	

Maywood No 1

TDSIC Elegible Cost Estimate		
	Material	$[redacted]
	Construction Contract Labor	$[redacted]
	Engineering, Ops or Other Labor	[redacted]
	Indirects / AFUDC	$[redacted]
	Sub-Total	$[redacted]
10%	Contingency	$[redacted]
	Sales Tax	[redacted]
TOTAL COSTS		$[redacted]

Assumptions/Qualifications

Note all details and assumptions related to project estimate development including:
Access to facilities
Weather/seasonal affects
Labor availability
Project duration
Basis for cost estimates or units of measure
Contingency assumptions and if applied at project total or component level

Maywood No 1

Modernization Project Estimate Summary			Planned Year 2020
WO Number (If Applicable)	Financial Number	Total Project Cost	TDSIC Program Category
517721	Maywood No. 1	$[redacted]	Circuit Rebuilds

Description of Work

Upgrade and Rehabilitate 13.2KV Overhead Distribution Circuit to current design standards. Location: Along alley from Farmsworth Road and Rybolt Road to Raymond (Airport)

Total Project Cost Summary

Cost Category		Project Cost Calculations	
Contract Labor	$[redacted]	Subtotal	$[redacted]
IPL Labor	[redacted]	Contingency	$[redacted]
Materials	$[redacted]	Subtotal + Contingency + Sales Tax	$[redacted]
Indirects/AFUDC	$[redacted]	E&S Loading	$[redacted]
		A&G Loading	
Sales Tax	$[redacted]	Total Loadings	$[redacted]
		Subtotal + Contingency + Loadings	$[redacted]
		Total Project Cost	$[redacted]

Public Appendix 8.9 Class 3 Estimate Example

Pole Replacement Project - Class 3 Estimate

	Type Percent	Average Annual Failures	Type Replaced Annually	Unit Replacement Cost	Replacemnt Cost per Type
13.2kv 1-Phase	75.00%	330	248	$[redacted]	$[redacted]
13.2kv 3-Phase	20.00%	330	66	$[redacted]	$[redacted]
13.2kv Double Ckt	1.25%	330	4	$[redacted]	$[redacted]
34.5kv 3-Phase	1.25%	330	4	$[redacted]	$[redacted]
34.5kv Double Ckt	1.25%	330	4	$[redacted]	$[redacted]
34.5kv 13.2kv UB	1.25%	330	4	$[redacted]	$[redacted]
Sub Total	100%	1,980	330		[redacted]
Treatment of Poles	16,500	330	16,170	$[redacted]	$[redacted]
Total Annual Cost Total					$3,192,288

Escalation 2.0% Estimate Year 2019

Plan Year	1	2	3	4	5	6	7
Year	2020	2021	2022	2023	2024	2025	2026
Cost	$3,256,134	$3,321,256	$3,387,682	$3,455,435	$3,524,544	$3,595,035	$3,666,935

Approx Number of Distribution poles on system	165,000
Approx Number of Annual Distribution Pole Inspections	16,500
Average failure rate	2.0%
Approx number of reject poles per year	330

PUBLIC Appendix 8.10 Class 4 Estimate Example

15 kV Switchgear Replacement Cost Breakdown (6 feeders)

6 Feeders												
Description	Qty	UoM	Unit/Mhr	Total Mhrs	Crew Rate	Labor Cost Total	Unit Material	Total Material	Unit Subcontract	Total Subcontract	Total Cost
Switchgear	6	ea	80	480	[redacted]						
Throat Addapter	1	ea	80	80							
DC Distribution Upgrade	1	ea	50	50							
Foundation Replacement	1	ea	200	200							
Stone	1	ea	20	20							
Relay/SCADA communication	1	ea	150	150							
Relay Engineering Access	1	ea	40	40							
Cabling											
Control Cables & conduits	500	ft	0.4	200							
Exit Cables	300	ft	0.94	282							
Ducts	300	ft	1	300							
New Manhole	1	ea	300	300							
Freight	1	ea									
Moving / Off loading	1	ea		20							
SubTotal											
Project Engineering 10%											
Project Management 5%											
Project Safety 5%											
SubTotal											
Project Contingency 10%											
AFUDC & Indirect Capital 10%											
Total				2122							

Appendix 8.11 Risk Reduction Benefit Monetization Report

Risk Reduction Benefit Monetization Report

Indianapolis Power & Light Company

IPL TDSIC Risk Reduction Benefit Monetization Report
Project No. 104713

Risk Reduction Benefit Monetization Report

prepared for

Indianapolis Power & Light Company
IPL TDSIC Risk Reduction Benefit Monetization Report
Indianapolis, Indiana

Project No. 104713

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
C&I	Commercial and Industrial
COF	Consequence of Failure
DOE	Department of Energy
ICE	Interruption Cost Estimate
IPL	Indianapolis Power & Light Company
LOF	Likelihood of Failure
NPV	Net Present Value
OH	Overhead
TDSIC	Transmission, Distribution and Storage System Improvement Charge
UG	Underground

1.0 INTRODUCTION AND OVERVIEW

Indianapolis Power and Light (IPL) engaged the services of Burns & McDonnell Engineering Company, Inc. (Burns & McDonnell) to monetize some of the risk reduction benefits of the Risk and Investment assessment (see IPL TDSIC Risk & Investment Report). This report outlines the approach Burns & McDonnell employed in monetizing risk reduction and the results of the analysis. The monetization analysis leverages a significant portion of the Asset Risk Model. For brevity, this report assumes the reader has read the IPL Transmission, Distribution and Storage System Improvement Charge (TDSIC) Risk & Investment Report to understand the more detailed analysis rather than duplicate sections here. However, it has been written to also communicate the general approach and results without the need to read the more detailed report.

The risk reduction benefit monetization was performed on the following projects: Substation Assets Replacement, Circuit Rebuilds, 4kv Conversion, XLPE Cable Replacement, and Remote End – Breaker Relay/Upgrades. At a high level, the risk reduction benefits were monetized at the asset level based on the following:

- 20 year evaluation profile
- Likelihood of Failure Profile calculated using the survivor curves and effective age based on the asset health algorithms
- Monetizing Consequence of Failure
  - Customer Reliability – using the DOE ICE Calculator
  - Reactive Failure Costs – assuming 40 percent cost adder to proactive replacement
- Monetized Risk Profile = Likelihood of Failure x Monetized Consequence of Failure
- Avoided cost calculated as the difference between the "Do Nothing" and Investment Scenario monetized risk profiles

The following sections outlines the risk reduction benefit monetization approach and results.

2.0 APPROACH

2.1 Financial Assumptions

The monetization approach described herein assumes the following discounted cash flow assumptions:

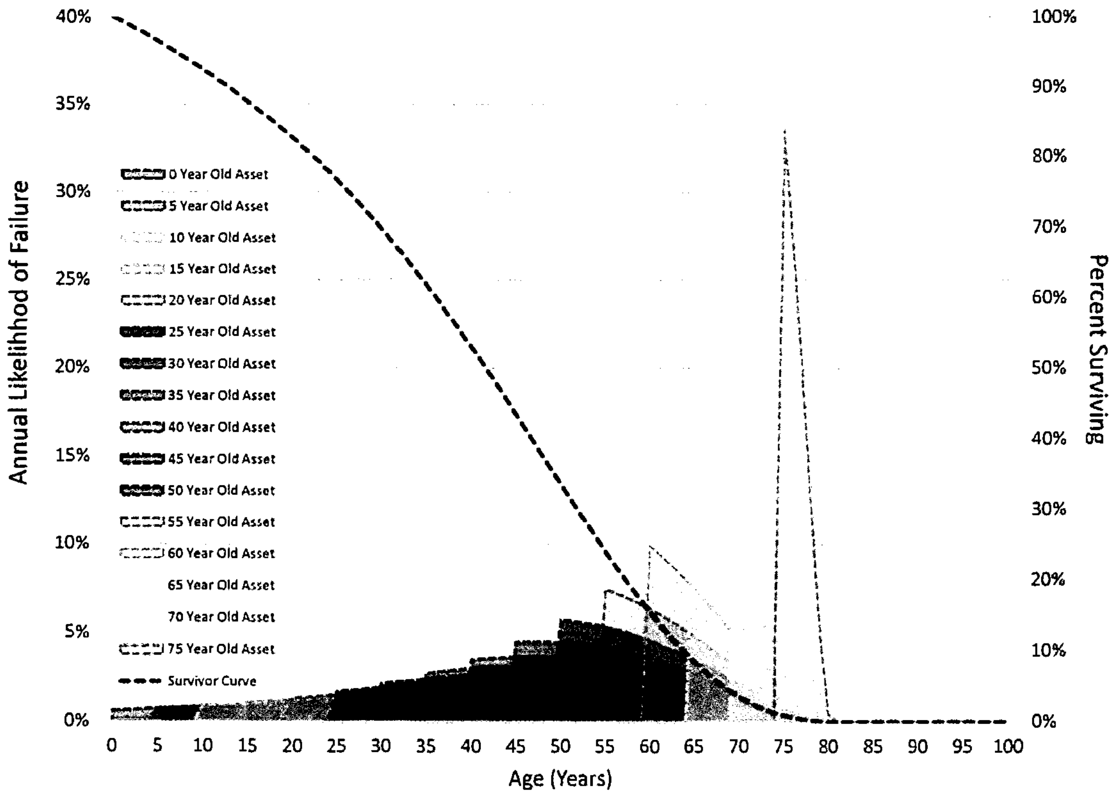
- An analysis period of 20 years
- Escalation rate of 2%
- A discount rate of 6.6%

2.2 Likelihood of Failure

The likelihood of failure (LOF) portion of the asset risk monetization utilized the developed survivor curves and effective age using Asset Health Indices outlined in the Asset Risk and Investment Assessment Report (see Section 2.2). The evaluation covered 1,690 substation assets and 218,175 overhead (OH) and underground (UG) sections. For each asset the LOF profile was estimated for the 'Do Nothing' and Investment scenarios.

Figure 2-1 shows the annual discrete LOF forecasts for an example survivor curve of an asset for various ages. The area of under each likelihood density function equals 100 percent. As the figure shows, younger assets have LOF profiles similar to normal distribution curves. But as assets age and the 100 percent is divided over fewer and fewer years, the annual discrete LOF increase dramatically, especially for assets past the average service life.

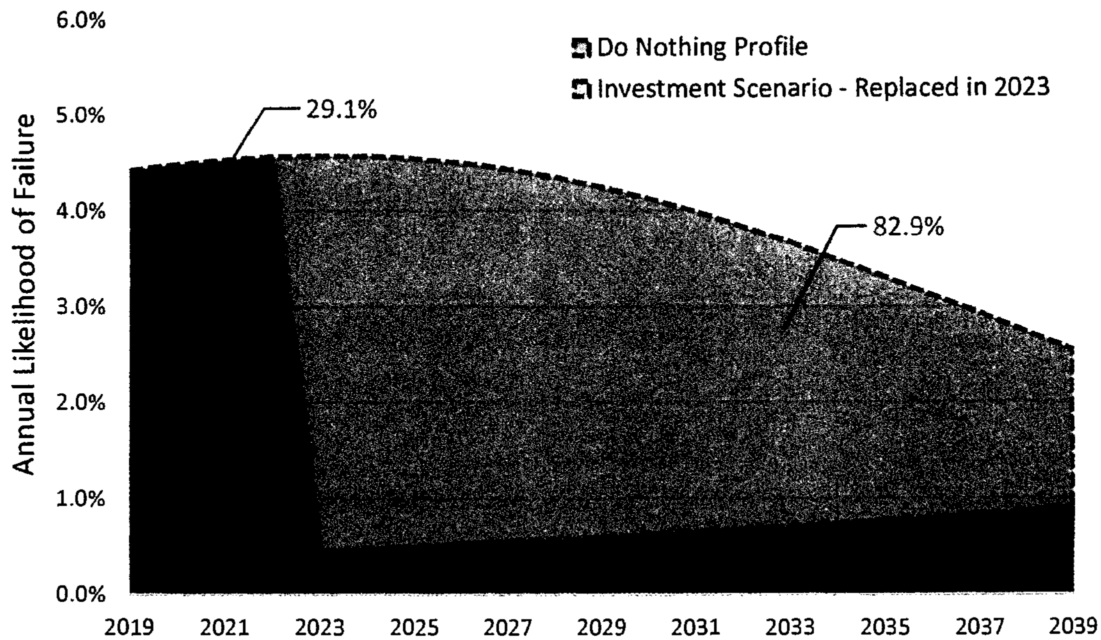
Figure 2-1: Likelihood of Failure Profiles for Various Asset Ages



The monetization approach considers the first 20 years of the LOF profile. It should be noted, that the likelihood of failure approach utilized in the Asset Risk Model and described in Burns & McDonnell's IPL TDSIC Asset Risk & Investment Assessment Report is over a 10 year period as outlined in Section 2.2.2. The asset risk monetization approach employs the same methodology for likelihood of failure using Survivor curves and asset health indices to estimate effective age. The main difference is the term used, 10 years versus 20 years.

Figure 2-2 shows the annual probabilities of failure over a 20-year period for Guion 132-39, a 138kV oil circuit breaker. The figure includes the LOF forecasts for both the 'Do Nothing' scenario and an Investment scenario where the asset is replaced in Year 4 of the TDSIC plan. With this approach, the monetization evaluation includes residual risk of the asset after it has been replaced. The difference between the area under each LOF forecast curve (82.9% and 29.1%) provides the benefit for the likelihood of failure component (53.8% benefit).

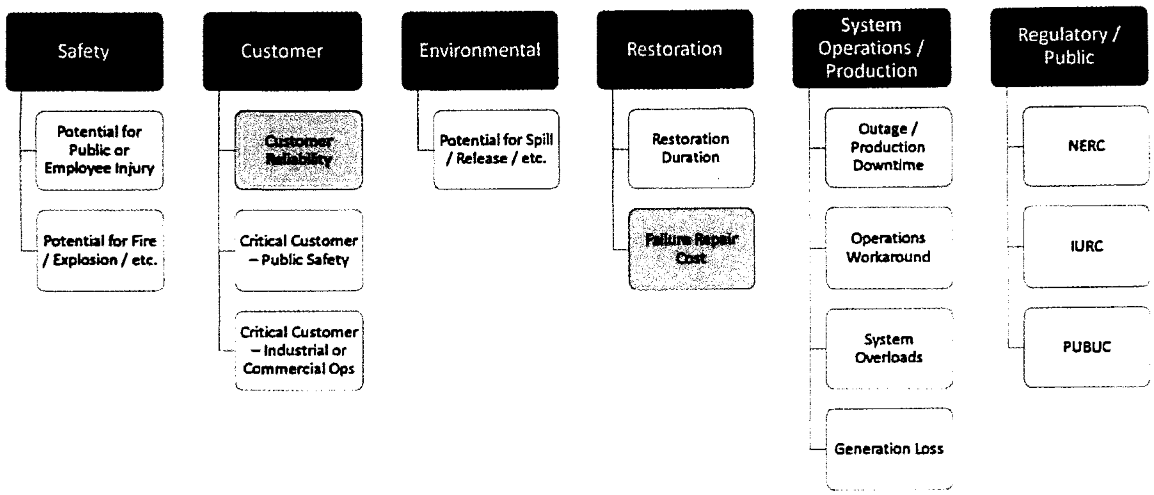
Figure 2-2: 'Do Nothing' and Investment Scenario Likelihood of Failure Forecasts



2.3 Monetized Consequence of Failure

The Asset Risk Model includes consequence scoring for 6 categories. Figure 2-3 provides a summary of the consequence of failure (COF) framework used in the Asset Risk Model. Section 2.3 of the Burns & McDonnell Asset Risk Model & Investment Report provides additional details on this COF framework. For this monetization evaluation the subcategories highlighted in green, Customer Reliability and Failure Repair Cost of the Restoration, were monetized. The sections below describe the approach to monetize these two subcategories.

Figure 2-3 Asset Risk Model: Consequence of Failure Criteria



2.3.1 Failure Repair Costs or Reactive Replacement Costs

This consequence category represents a direct cost to the utility that is passed through to customers. Both the Asset Risk Model and Monetization Analyses assume reactive replacement costs are approximately 40 percent more than proactive. Factors that contribute to this increase include:

- Overtime
- Premiums to make last minute purchase of equipment and materials
- Mobilization and rework related to making temporary fixes and returning to effect permanent repairs / replacements
- Schedule disruption in reassigning crews, previously deployed on other work, on emergent activities

2.3.2 Residential and Small C&I Customer Reliability

The Asset Risk and Investment Analysis scores customer reliability consequence for residential and small commercial and industrial (C&I) customers by using the DOE ICE Calculator and converts the interruption costs to a consequence score consistent with the holistic and integrated COF framework. The monetization analysis uses the same interruption costs for primary and transmission conductor, while utilizing a conservative assumption that pole and tower failures will not results in a monetized reliability cost to customer.

The interruption costs were first determined by developing outage scenarios, which were then assigned to each asset. The scenarios were developed by analyzing historical system outages for the various asset classes taking into account the number of customers an asset would serve. Additionally, the scenarios assume deployment of the advanced control system. Each outage scenario was modeled within the DOE ICE Calculator to determine the interruption costs on an asset by asset basis.

The Interruption Cost Estimate (ICE) Calculator is an electric reliability planning tool developed by Freeman, Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy (DOE).

The analysis includes 23 outage scenarios. One example scenario is a 3-phase overhead primary on the backbone. This example scenario assumes 875 customers would be out of service for 5 minutes before the advanced control system sectionalizes the circuit. Following the sectionalizing, the scenario assumes 400 customers to be out of service for an additional 55 minutes (60 minute outage in total). Review of outage records for this scenario indicates an average time to restore service of 60 minutes.

3.0 RESULTS

Figure 3-1 shows the annual cash flows (escalated nominal) profile by cash flow type for the monetized benefits and TDSIC investment. The figure shows net positive benefits by year 5.

Figure 3-1 Annual Cash Flow Profile

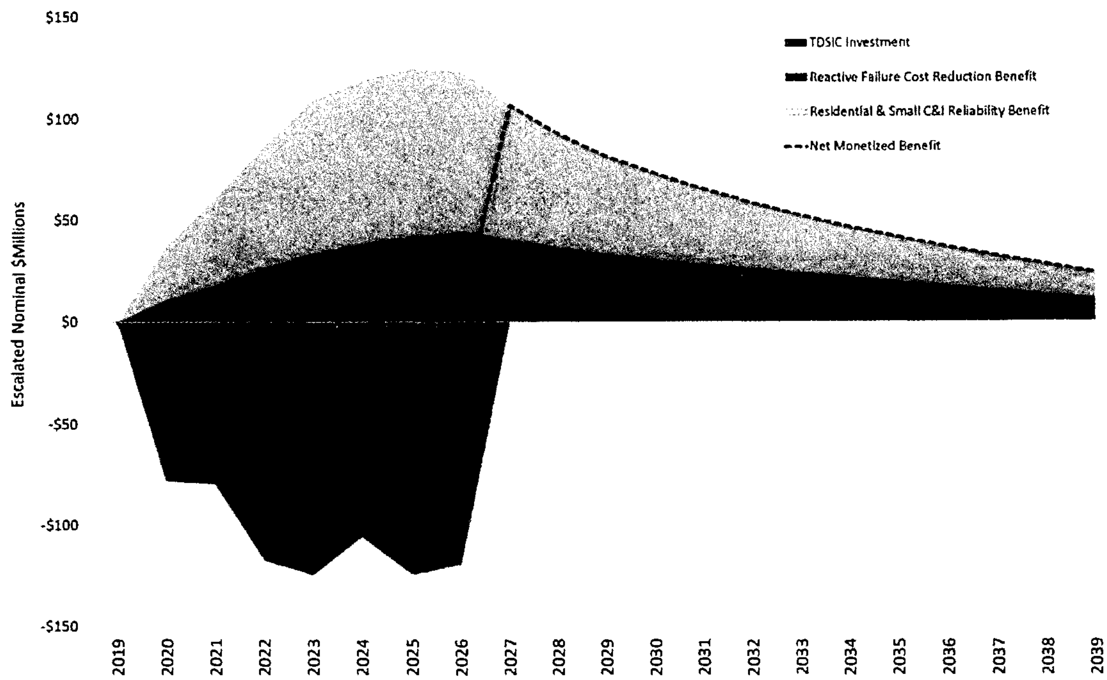


Figure 3-2 provides an alternative view showing the cumulative annual cash flows to date. The monetized benefits provide a net benefit of approximately $658 million over the 20 year period. Additionally, the profile shows a break-even point by year 8.

Figure 3-3 provides a summary of the 20 year escalated nominal cash flows and Net Present Value (NPV) by cash flow type. The monetized benefits provide total (or gross) NPV benefits of $840 million and net benefits of $268 million.

Figure 3-2 Cumulative Annual Cash Flow Profile

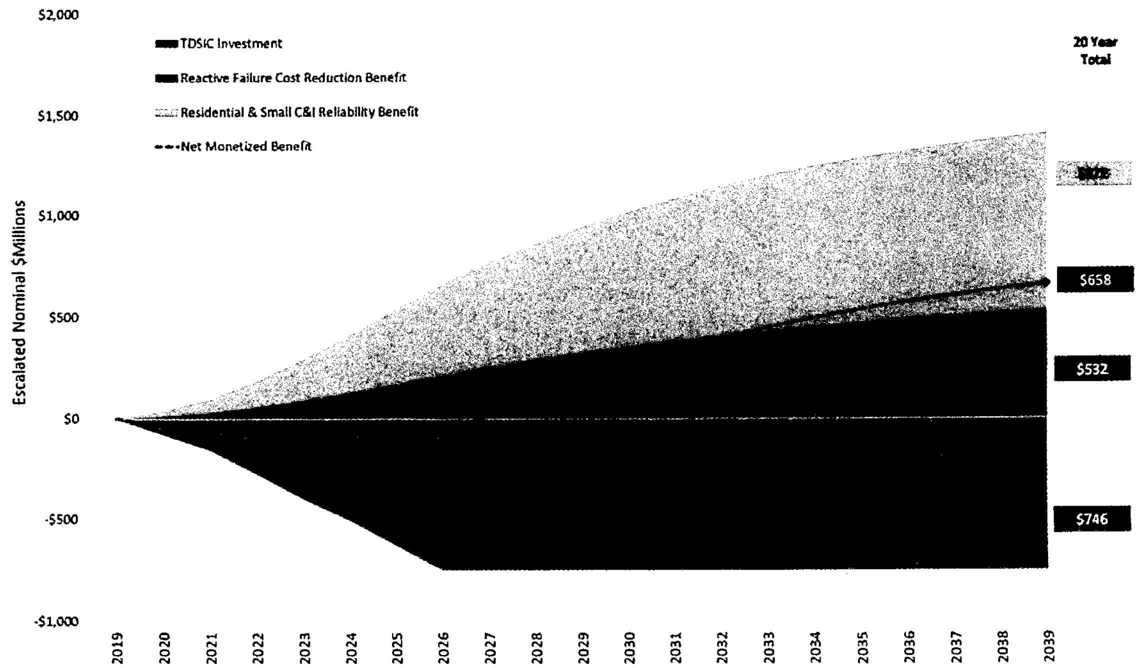
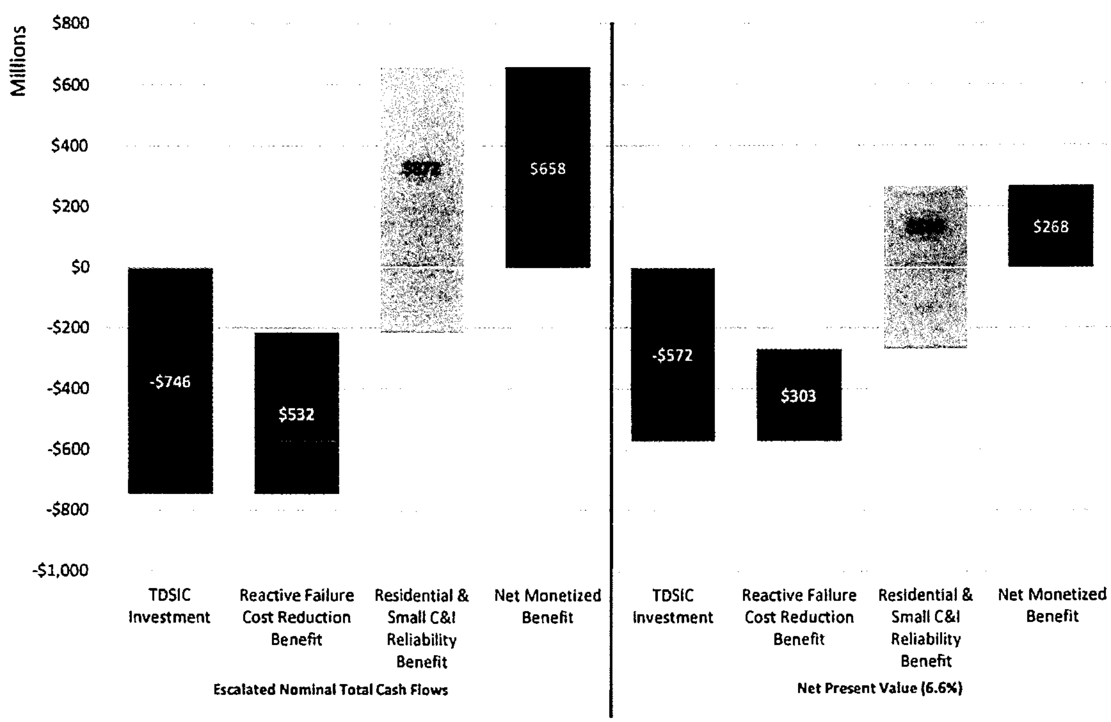


Figure 3-3 Cash Flow and NPV Summary



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