STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF THE CITY OF CRAWFORDSVILLE, INDIANA, BY AND THROUGH ITS MUNICIPAL ELECTRIC UTILITY, CRAWFORDSVILLE ELECTRIC LIGHT AND POWER, FOR APPROVAL OF A NEW SCHEDULE OF RATES AND CHARGES FOR ELECTRIC SERVICE AND FOR APPROVAL TO MODIFY ITS ENERGY COST ADJUSTMENT PROCEDURES	)))))))))	**CAUSE NO. 45420**

PRE-FILED VERIFIED DIRECT TESTIMONY OF

LAURIE A. TOMCZYK

AND ATTACHMENTS LAT-1 THRU LAT-5

ON BEHALF OF PETITIONER

CRAWFORDSVILLE POWER & LIGHT

PETITIONER'S EXHIBIT NO. 5

AUGUST 19, 2020

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I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. My name is Laurie Tomczyk. I am employed as an Executive Consultant by NewGen Strategies and Solutions, LLC ("NewGen"). My business address is 4528 Trails End, Lapeer, Michigan. NewGen is a consulting firm that specializes in utility rates, engineering economics, financial accounting, asset valuation, appraisals, and business strategy for electric, natural gas, solid waste, water, and wastewater utilities. I am testifying on behalf of the Petitioner, Crawfordsville Electric Light & Power ("CEL&P" or the "Utility"), which is the electric utility owned and operated by the City of Crawfordsville, Indiana ("Crawfordsville").

Q2. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I have been employed by NewGen since January 2014. Prior to joining NewGen, I was employed by R. W. Beck, Inc. (or one of its successors) since 1988. R.W. Beck, Inc. was eventually acquired by Science Applications International Corporation ("SAIC"), which is now Leidos Engineering LLC. Prior to joining R. W. Beck, I was employed by HDR, Inc. in Omaha, Nebraska from 1986 through mid-1988. I have over 30 years of experience in providing management consulting services to clients involved in the electric power, water, and solid waste management industries. I specialize in electric utility revenue requirement analyses, cost of service and rate design studies, financial projections, expert witness services, and other engineering and economic analyses. I have been an instructor on behalf of Electric Utility Consultants, Inc. for courses on cost of service concepts and techniques and rate design for electric utilities. I am a registered professional engineer in the State of Colorado.

Q3. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE INDIANA UTILITY REGULATORY COMMISSION ("IURC" OR "COMMISSION")?

A. Yes, my testimony before the IURC, as well as other state commissions on utility rate making matters is summarized in my resume included as Attachment LAT-1.

Q4. WHAT ARE THE PURPOSES OF YOUR TESTIMONY?

A. The purposes of my testimony are to discuss and recommend the following:

1) Changes to CEL&P's calculation of its Energy Cost Adjustment ("ECA") tracker;

2) Changes to CELP's Non-Recurring Charges; and

3) Changes to CELP's LED fixture charges for streetlighting and outdoor lighting.

Q5. WHAT ATTACHMENTS ARE YOU SPONSORING IN THIS CAUSE?

A. I am sponsoring the following attachments to my direct testimony:

- Attachment LAT-1 – Resume of Laurie A. Tomczyk
- Attachment LAT-2 – Final Order in IURC Cause No. 36835-S3, December 13, 1989
- Attachment LAT-3 – New ECA Model
- Attachment LAT-4 – Calculation of Proposed Non-Recurring Charges
- Attachment LAT-5- Calculation of Proposed LED Lighting Rates

Q6. WERE THESE ATTACHMENTS PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

II. ECA CALCULATIONS

Q7. PLEASE EXPLAIN CEL&P'S ECA TRACKER.

A. Because CEL&P purchases its power exclusively from IMPA, the ECA was originally established by the Commission in Cause No. 36835-S1 in 1983 as a mechanism by which CEL&P and other IMPA members could obtain Commission approval of periodic energy cost adjustment and power tracking procedures that would allow CEL&P to track to its retail customers' increases or decreases in the cost of power and energy CEL&P purchases from IMPA outside of a base rate case. CEL&P makes quarterly ECA filings with the IURC.

Q8. WHEN WAS THIS PROCESS ESTABLISHED?

A. The use of a tracking mechanism to recover wholesale energy costs for Commission regulated members of IMPA was first approved on January 11, 1983 in Cause No. 36835-S1, and subsequently revised in orders in subdockets S2 (Final Order issued Mary 2, 1984) and S3 (Final Order issued December 13, 1989)[1] ("1989 ECA Order"). These procedures allow Crawfordsville to appropriately reconcile any over or under collection of wholesale energy costs on a quarterly basis. As approved in the 1989 ECA Order, CEL&P submits to the Commission ECA forms that calculate the per unit changes between CEL&P's current wholesale power costs and the wholesale power costs reflected in CEL&P's current rates, and then CEL&P multiplies those changes by the next quarter's estimated billing determinants.[2] Further, to eliminate the possibility of overcollection or undercollection, the form includes a base rate change reconciliation procedure under which each quarter's estimation of the billing

[1] *In the Matter of the Indiana Municipal Power Agency and the Indiana Cities and Towns, Members Thereof, to Modify, Simplify and Make More Equitable Certain Tracking Procedures Heretofore Authorized By This Commission to Track Increases or Decreases in the Cost of Purchased Power and Energy by Such Members From the Indiana Municipal Power Agency*, IURC Cause No. 36835-S3, December 13, 1989. Please note that the Final Order in this Cause appears to be omitted from Westlaw's repository of Commission orders and hence no Westlaw citation is available. For ease of reference, it is included as Attachment LAT-2.

[2] *Id*. at *6-*7.

determinants used by CEL&P to bill its ratepayers is reconciled with the actual billing determinants used by IMPA to bill CEL&P. The form requires CEL&P to take into consideration IMPA's base rates, together with IMPA's energy cost adjustment factor, in determining a quarterly variance between what CEL&P billed its ratepayers and what IMPA billed CEL&P, resulting in a dollar for dollar flow through of IMPA's base rates and energy cost adjustment charges. The form also requires CEL&P to report current estimates of CEL&P's generating costs and payments from IMPA on a quarterly basis.[3]

Q9. AT A HIGH LEVEL, PLEASE DESCRIBE THE STEPS FOLLOWED TO CALCULATE THE ECA RATES.

A. The ECA calculations first determine incremental changes in IMPA power costs to CEL&P between the quarter when the ECA rates will be in effect and those from CEL&P's last rate case. These incremental costs are then allocated to the above categories of customer classes based on the cost-of-service allocators from the last rate study, as adjusted for changes in load since the last rate study. Next, the amount of historic under-recovery or over-recovery for each of the categories of customer classes are then added or subtracted, respectively, to the incremental power costs. The results for each of the categories of customer classes are then divided by the appropriate billing determinants to arrive at the ECA rates identified in the quarterly filings.

Q10. HOW ARE THE HISTORIC UNDER OR OVER RECOVERY AMOUNTS DETERMINED?

[3] *Id.* at *8.

A. For the historic period, the incremental IMPA power costs to CEL&P as compared to those in CEL&P's last rate case are first determined. These incremental costs are then allocated to the above categories of customer classes based on the cost-of-service allocators from the last rate study, as adjusted for changes in load since the last rate study. These amounts are then compared to actual revenues from ECA rates during the historic period for each of the customer class categories. The net of these amounts equals the historic over or under recovery.

Q11. HISTORICALLY, PLEASE IDENTIFY THE TYPES OF ECA RATES THAT HAVE BEEN CALCULATED USING THE CURRENT ECA MODEL.

A. Historically, CELP's ECA rates have been calculated in the ECA model for each of the following categories of rate schedules:

- Residential Service: Rate Schedule RS
- General Power and Municipal Power Service: Rate Schedules GP and MP
- Primary Power Service: Rate Schedule PP
- Outdoor Lighting: Rate Schedule PP
- Streetlighting: Rate Schedule SL
- Traffic Signals: Rate Schedule TS

Q12. IN TERMS OF CALCULATING THE ECA RATES BASED ON DEMAND CHARGES VERSUS ENERGY CHARGES, HOW HAVE CEL&P'S ECA RATES HISTORICALLY BEEN ASSESSED WITHIN EACH OF THE ABOVE CATEGORIES OF RATE SCHEDULES?

A. Historically, ECA rates have been calculated and assessed to the above categories of rate schedules all on an energy basis (i.e., dollar per kWh charges), except for Primary Power Service. For Primary Power Service, ECA rates have been calculated and assessed on both a demand and energy basis (i.e., dollar per kW charge and dollar per kWh charge, respectively). This is consistent with how CEL&P charges base rates. The Primary Power Service base rate schedule is currently the only rate schedule for which both demand and energy charges are assessed as part of their base rates.

Q13. ARE YOU PROPOSING ANY UPDATES TO CEL&P'S CURRENT ECA MODEL?

A. Yes. As discussed in Mr. Mancinelli's direct testimony, CEL&P is proposing to assess both demand and energy charges as part of their base rates to both the General Power Service and Municipal Power Service rate schedules. Consistent with these proposed changes to CEL&P's base rates, I am proposing that CEL&P assess both demand and energy ECA rates to the General Power Service and Municipal Power Service rate schedule category. ECA rates for the other categories of rate schedules would continue to be charged on an energy basis only.

Q14. HAVE YOU DEVELOPED A RECOMMENDED ECA MODEL THAT INCORPORATES THESE CHANGES?

A. Yes, the updated model is provided in Attachment LAT-3.

III. ADJUSTMENT 2 TO THE REVENUE REQUIREMENT STUDY

Q15. PLEASE EXPLAIN THE BASIS OF ADJUSTMENT 2 TO THE REVENUE REQUIREMENT STUDY FOR PURCHASED POWER COSTS.

A. During the test year period, actual IMPA rates that were in effect from March through December 2019 differed from those in effect during January and February 2020. Therefore, purchased power costs were adjusted to reflect a full year at the IMPA rates that became effective January 1, 2020. The following table summarizes the inputs and calculations used to adjust the purchased power costs.

Table LAT-1
CEL&P Power Cost Adjustment

Line No.		A Actual	B Adjustments	C Pro Forma
1	**Demand Billing Determinants kW**			
2	March thru December 2019	624,661	-	624,661
3	January thru February 2020	109,893	-	109,893
4	Total	734,554	-	734,554
5	**Energy Billing Determinants kWh**			
6	March thru December 2019	338,427,960	-	338,427,960
7	January thru February 2020	64,335,908	-	64,335,908
8	Total	402,763,868	-	402,763,868
9	**IMPA Base Demand Rates $/kW**			
10	March thru December 2019	$24.70	$1.52	$26.22
11	January thru February 2020	$26.22	$0.00	$26.22
12	**IMPA ECA Demand Rates $/kW**			
13	March thru December 2019	($2.45)	($0.81)	($3.26)
14	January thru February 2020	($3.26)	$0.00	($3.26)
15	**IMPA Base Energy Rates $/kWh**			
16	March thru December 2019	$0.030772	($0.001897)	$0.028875
17	January thru February 2020	$0.028875	$0.000000	$0.028875
18	**IMPA ECA Energy Rates $/kWh**			
19	March thru December 2019	($0.003505)	$0.001020	($0.002485)
20	January thru February 2020	($0.002485)	$0.000000	($0.002485)
21	**IMPA Demand Charges (Base & ECA)**			
22	March thru December 2019	$13,897,458	$442,885	$14,340,343
23	January thru February 2020	$2,522,814	$0	$2,522,814
24	Total	$16,420,272	$442,885	$16,863,156
25	**IMPA Demand Charges (Base & ECA)**			
26	March thru December 2019	$9,227,915	($296,801)	$8,931,114
27	January thru February 2020	$1,697,825	$0	$1,697,825
28	Total	$10,925,740	($296,801)	$10,628,938
29	**Total IMPA Charges**	$27,346,011	$146,083	$27,492,095

Q16. PLEASE EXPLAIN THE BASIS OF THE ACTUAL IMPA POWER COSTS AS SHOWN IN TABLE LAT-1.

A. At Lines 1 through 8 of Column A of Table LAT-1, the actual demand kW and energy kWh used by IMPA to calculate the actual bills from IMPA to CEL&P for the test year period from March 1, 2019, through February 29, 2020, are shown. The actual IMPA rates in effect during that time period are shown in Column A of Table LAT-1 at Lines 9 through 20. The actual annual charges based on these billing determinants and rates are shown in Column A of Table LAT-1 at Lines 21 through 29.

Q17. PLEASE EXPLAIN THE BASIS OF THE PRO FORMA IMPA POWER COSTS SHOWN IN TABLE LAT-1.

B. The actual demand kW and energy kWh, as shown in Column A of Table LAT-1 at Lines 1 through 8, were used to calculate the pro forma IMPA power costs as shown in Column C of Table LAT-1 at Lines 1 through 8. The IMPA rates used to calculate the pro forma IMPA power costs are the IMPA rates that became effective January 1, 2020, as shown in Column C of Table LAT-1 at Lines 9 through 20. The pro forma charges based on the pro forma billing determinants and rates are shown in Column C of Table LAT-1 at Lines 21 through 29. The resulting actual and pro forma purchased power costs are shown in Line 29 of Table LAT-1, with the resulting adjustment to purchased power costs equal to $146,083.

IV. CHANGES TO CELP'S NON-RECURRING CHARGES

Q18. PLEASE EXPLAIN THE PROPOSED CHANGES TO APPENDIX B IN CELP'S TARIFF, WHICH CONTAINS THE UTILITY'S PROPOSED NON-RECURRING CHARGES.

A. I am proposing to change the following non-recurring charges currently in CEL&P's Appendix B – Non-Recurring Charges (referred to collectively as "Non-Recurring Charges") including the Service Deposit, Return Check, Reconnect/Disconnect, Temporary Service, Meter Test, Service Call, and Late Payment Charges by updating these fees for current labor, truck, and materials costs.[4] In the five years since CELP's last rate study, the costs of labor and materials have increased. I am also proposing to add Meter Base, Electrical Permit, and Lot Fee Charges to CEL&P's Appendix B.

Q19. ARE THE PROPOSED NON-RECURRING CHARGES BASED ON COST OF SERVICE?

A. My recommended Non-Recurring Charges are equal to or less than the calculated cost for CEL&P to provide those services. CEL&P provided me with hourly labor and truck costs and estimated hours for each type of service. I used this information, as well as information from the Cost of Service and Rate Design analyses as presented and discussed in Mr. Mancinelli's direct testimony and attachments, to calculate the costs for each type of service as shown in Attachment LAT-4.

Q20. DID YOU BASE YOUR RECOMMENDED NON-RECURRING CHARGES ON ANY OTHER INFORMATION BEYOND COST OF SERVICE?

A. Yes. In developing the recommended Non-Recurring Charges, I also analyzed neighboring utilities' similar fees and charges to provide a benchmarking check against the fees I have proposed. The following table provides a summary of the current and proposed Non-Recurring Charges, as well as the costs to CEL&P for providing the services. Attachment LAT-4 provides the inputs, assumptions, and methodologies used to calculate the costs to CEL&P for providing the associated services and summarizes the benchmarking data regarding non-recurring fees charged by neighboring utilities.

[4] See Attachment JAM-4 of the Direct Testimony of Mr. Mancinelli for a copy of the proposed tariff, including non-recurring charges.

Table LAT-2
CEL&P Current and Proposed Non-Recurring Charges and Costs

Type of Charge	Units	CEL&P Current	CEL&P Proposed	CELP Cost
Service Deposit				
Rate Sched RS	Minimum $/Deposit[1]	$ 50.00	$ 60.00	$ 60.00
Rate Sched GP, PP, and IP	Minimum $/Deposit[2]	$ 100.00	$ 120.00	$ 120.00
Return Check Charge	$/Returned Check[3]	$ 25.00	$ 25.00	$ 23.77
Reconnect/Disconnect Charge				
During normal Utilty hours	$/Reconnect or Disconnect	$ 40.00	$ 45.00	$ 98.17
Outside normal Utility hours	$/Reconnect or Disconnect	$ 100.00	$ 120.00	$ 127.26
Temporary Service Charge	$/Temporary Service[4]	$ 100.00	$ 150.00	$ 247.06
Meter Test Charge	$/Meter Test[5]	$ 40.00	$ 50.00	$ 214.51
Service Call Charge				
Outside normal Utility hours	$/Service Call	$ 200.00	$ 250.00	$ 534.56
Late Payment Charge	% of Unpaid Balance	4%	5%	5%
Meter Base Charge				
Residential Customers	$/Meter Base	NA	$ 50.00	$ 50.00
Commercial Customers	$/Meter Base	NA	$ 100.00	Over $100.00
Electric Permit Fee	$/Permit	NA	$ 50.00	$ 908.32
Lot Fee	$/Lot[6]	NA	$ 1,000.00	$ 1,000.00

1 Minimum for Residential Service to a maximum of 2 months anticipated usage. The actual amount shall be based on the results of a credit check.
2 Minimum for General Power, Primary Power, and Industrial Power Service. The actual amount shall be based on the results of a credit check.
3 For the current charge, the greater of $25.00 or 5% (but not more than $250) of the amount of the check. For the proposed charge, the greater of $25.00 or 6% (but not more than $250) of the amount of the check.
4 When no more than a single span service drop and meter are required.
5 If customer requests a meter test less frequently than in a 36-month period and upon test, the meter accuracy is less than 3% error.
6 Based on 8 years to recover investment.

Q21. ARE YOUR RECOMMENDED NON-RECURRING CHARGES REASONABLE AS COMPARED TO THE ESTIMATED COST OF SERVICE AND IN COMPARISON TO NEIGHBORING UTILITIES?

A. Yes. As shown in in Attachment LAT-4, the recommended Non-Recurring Charges are in-line or less than the cost of service, and are similar to or in the range of fees assessed by neighboring utilities for similar services.

V. LIGHTING RATE DESIGN

Q22. GENERALLY, HOW WERE THE PROPOSED FIXTURE CHARGES FOR NON-LED LIGHTS SHOWN IN MR. MANCINELLI'S ATTACHMENT JAM-4 DETERMINED?

A. For non-LED lights, across-the-board adjustments were made to current fixture charges for the Street Lighting, Outdoor Lighting, and Traffic Signals classes based on the revenue targets by phase-in period as identified for these classes as part of the overall rate design. These revenue targets are discussed in Mr. Mancinelli's direct testimony on rate design and shown in Attachment JAM-4.

Q23. GENERALLY, HOW WERE THE PROPOSED FIXTURE CHARGES FOR STREETLIGHT LED LIGHTS DEVELOPED?

A. CEL&P currently has LED streetlighting rates, but we updated them for purposes of the filing. The following table summarizes the approach used to design the proposed LED streetlight rates. More details are provided in Attachment LAT-5. First, the per fixture operating costs for the HPS streetlights by wattage and the equivalent LED streetlights by equivalent wattage were calculated based on the cost-of-service results in Attachment JAM-2. These operating costs are shown in Lines 1 and 2 of following table.

Table LAT-3
Proposed LED Streetlighting Fixture Charges

Line No.	HPS Streetlights / Equivalent LED Streetlights	A 100 W HPS 47 W LED	B $/Fixture 250 W HPS 81 W LED	C 400 W HPS 142 W LED
1	HPS COS SL Operating Costs	$ 11.66	$ 13.09	$ 15.24
2	Equiv LED COS SL Operating Costs	$ 9.19	$ 9.85	$ 10.93
3	Difference (LED SL Costs Minus HPS SL Costs)	$ (2.47)	$ (3.24)	$ (4.31)
4	Proposed Phase 2 HPS SL Fixture Charges	$ 6.80	$ 27.55	$ 45.03
5	Less Difference in LED SL vs HPS SL Operating Costs	$ (2.47)	$ (3.24)	$ (4.31)
6	Proposed LED SL Fixture Charges	$ 4.33	$ 24.31	$ 40.72

The differences in operating costs for the LED and HPS streetlights were then calculated as shown in the above table on Line 3. These differences were then applied to the proposed Phase 2 HPS streetlight fixture charges to determine the proposed LED streetlight fixture charges as shown in Lines 4 through 6 of the above table. Line 6 in the above table shows the proposed LED streetlighting fixture charges.

Q24. GENERALLY, HOW WERE THE PROPOSED FIXTURE CHARGES FOR LED OUTDOOR LED LIGHTING DEVELOPED?

A. CEL&P currently does not have any LED outdoor lighting rates, but they were developed as part of this filing. A very similar rate design process was used for LED outdoor lights as for LED streetlights. The following table summarizes the approach used to design the proposed LED outdoor lighting rates. More details are provided in Attachment LAT-5. First, the per fixture operating costs for the HPS outdoor lights by wattage and the equivalent LED outdoor lights by equivalent wattage were calculated based on the cost-of-service results in Attachment JAM-2. These operating costs are shown in Lines 1 and 2 of following table.

Table LAT-4
Proposed LED Outdoor Lighting Fixture Charges

Line No.	HPS Outdoor Lights / Equivalent LED Outdoor Lights	A 100 W HPS 47 W LED	B $/Fixture 250 W HPS 81 W LED	C 400 W HPS 142 W LED
1	HPS COS OL Operating Costs	$ 4.29	$ 5.71	$ 7.84
2	Equiv LED COS OL Operating Costs	$ 3.27	$ 3.93	$ 5.00
3	Difference (LED OL Costs Minus HPS OL Costs)	$ (1.01)	$ (1.78)	$ (2.84)
4	Proposed Phase 2 HPS OL Fixture Charges	$ 4.97	$ 12.81	$ 34.85
5	Less Difference in LED OL vs HPS OL Operating Costs	$ (1.01)	$ (1.78)	$ (2.84)
6	Proposed LED OL Fixture Charges	$ 3.96	$ 11.03	$ 32.01

The differences in operating costs for the LED and HPS outdoor lights were then calculated as shown in the above table on Line 3. These differences were then applied to the proposed Phase 2 HPS outdoor lighting fixture charges to determine the proposed LED streetlight fixture charges as shown in Lines 4 through 6 of the above table. Line 6 in the above table shows the proposed LED outdoor lighting fixture charges.

VI. SUMMARY AND CONCLUSIONS

Q25. PLEASE PROVIDE A SUMMARY OF YOUR RECOMMENDATIONS.

A. I recommend that the IURC approve the following as identified earlier in my testimony:

1) Proposed changes to the calculation of future ECA rates for CEL&P;

2) Proposed Non-Recurring Charges; and

3) Proposed LED fixture charges for streetlighting and outdoor lighting.

Q26. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

VERIFICATION

I affirm under the penalties of perjury that the foregoing prefiled verified direct testimony is true to the best of my knowledge, information and belief as of the date here filed.

Laurie A. Tomczyk

Laurie A. Tomczyk

NewGen Strategies & Solutions

Laurie A. Tomczyk, PE
Executive Consultant, Energy Practice
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Ms. Tomczyk has over 30 years of experience in providing management consulting services to clients involved in the electric power, water, and solid waste management industries. She specializes in electric utility revenue requirement analyses, cost of service and rate design studies, financial projections, expert witness services, and other engineering and economic analyses. Her rate-related projects have included studies to develop retail electric, retail water, transmission, ancillary service, standby, and special contract rates. She also has experience in net energy metering, decoupling, and opt-out programs.

Ms. Tomczyk has provided expert witness testimony on revenue requirement cost of service issues before public utility commissions, and she has provided other types of cost of service and rate-related litigation support. She has been an instructor on behalf of Electric Utility Consultants, Inc. for courses on cost of service concepts and techniques and rate design for electric utilities.

Ms. Tomczyk joined NewGen Strategies & Solutions as an Executive Consultant in 2014. Prior to joining the firm, she provided utility consulting services while employed at R. W. Beck, Inc. and its successor firm, SAIC, for 25 years.

EDUCATION

- Bachelor of Science in Mechanical Engineering, University of Nebraska

PROFESSIONAL REGISTRATIONS/CERTIFICATIONS

- Registered Professional Engineer (PE), Mechanical, Colorado

KEY EXPERTISE

- Revenue Requirements
- Cost of Service and Rate Design
- Expert Witness and Litigation Support
- Financial Projections
- Engineering/Economic Analyses
- Depreciation Studies

RELEVANT EXPERIENCE

Revenue Requirement, Cost of Service, and Rate Design

Ms. Tomczyk leads and participates in retail revenue requirement, cost of service, and rate design studies for electric utilities. The services she provides include development of historical and projected revenue requirements and the development of detailed cost of service and rate design models. Ms. Tomczyk has utilized numerous cost allocation methods and compared the revenue requirements under the various cost of service methods in order to evaluate the most appropriate cost of service methodologies for specific clients.

Additionally, Ms. Tomczyk has worked on diverse ratemaking issues such as standby service rates, net energy metering rates, wheeling rates, feed-in tariffs, and cost of service levels. She has used projected test year analyses to assess revenue requirements; assessed the cost of service changes for multiple customer classes; developed new rates for customer classes based on pre-defined overall percentage rate increases; and determined whether a return on rate base or Times Interest Earned Ratio should be used for ratemaking purposes. A sample listing of Ms. Tomczyk's cost of service and rate design clients by service offering is shown below.

Laurie A. Tomczyk, PE

Executive Consultant, Energy Practice

Electric Revenue Requirement, Unbundled Cost of Service Analysis, and Rate Design Studies

- United Power Electric Cooperative, Colorado
- Golden Valley Electric Cooperative, Alaska
- Homer Electric Association, Alaska
- Bryan Texas Utilities, Texas
- Brownsville Public Utilities Board, Texas
- Kaua'i Island Utility Cooperative, Hawai'i
- BC Hydro, British Colombia, Canada
- Lafayette Utilities System, Louisiana
- Cleveland Public Power, Ohio
- CPS Energy, Texas
- Tri-State Generation & Transmission Association, Inc., Colorado
- Austin Energy, Texas
- Farmington Electric Utility System, New Mexico Water and Electric Board, Oregon
- Garland Power & Light, Texas
- United Power Electric Cooperative, Colorado
- Guam Power Authority, Guam
- U.S. Army, California, Georgia, New York, and Virginia
- Fayetteville Public Works Commission, North Carolina

Competitive Retail Rate Assessments

- Garland Power and Light, Texas
- Brownsville Public Utilities Board, Texas

Electric Transmission and Ancillary Service Rates

- Golden Valley Electric Cooperative, Alaska
- Homer Electric Association, Alaska
- Lubbock Power & Light, Texas
- Brownsville Public Utilities Board, Texas
- Greenville Electric Utility System, Texas

Net Energy Metering and Standby Rates

- Kaua'i Island Utility Cooperative, Hawai'i
- Homer Electric Association, Alaska
- Golden Valley Electric Cooperative, Alaska
- Madisonville Municipal Utilities, Kentucky

Electric Special Contract Rates

- Homer Electric Association, Alaska
- Alaska Golden Valley Electric Cooperative, Alaska

Electric Decoupling Programs

- Kaua'i Island Utility Cooperative, Hawai'i
- Guam Power Authority, Guam

Opt-Out Program Associated with Advanced Electric Metering Infrastructure Project

- Kaua'i Island Utility Cooperative, Hawai'i

Expert Witness and Litigation Support

Ms. Tomczyk offers expert testimony regarding cost of service, rate design and ratemaking issues before local and state regulatory bodies and courts. She has developed revenue requirements, rate base, cost of service analysis, and rate design and associated testimony to be filed with state commissions; including design of retail, transmission, and ancillary services rates. She has developed a standby rate report filed with the state commission as part of the standby rate service tariff filing. She has provided written testimony and other litigation support on behalf of clients pertaining to their revenue requirements, cost of service studies, and equity management plans.

Additionally, Ms. Tomczyk has developed comments provided on behalf of a customer associations related to a state commission's investigation to analyze the strengths and weaknesses of marginal cost of service studies, embedded cost of service studies, the reconciliation process, and how this impacts rate classes. She has also reviewed wholesale energy provider's unbundled financial statements, calculation of equipment, projected wholesale customer patronage capital accruals, and estimated rate impacts associated with the wholesale utility's proposed construction of a new generation plant. Ms. Tomczyk has provided testimony and other types of litigation support for the following clients:

- Golden Valley Electric Cooperative, Alaska
- Homer Electric Association, Alaska
- Guam Power Authority, Guam
- B.C. Hydro, British Columbia
- SABIC Innovative Plastics, Indiana
- Kaua'i Island Utility Cooperative, Hawai'i
- Nevada Resorts Association, Nevada
- Tri-State Generation & Transmission Association, Inc., Colorado
- U.S. Army, Texas and New York

Financial Projections

Ms. Tomczyk is responsible for the development of financial and economic analyses for utility clients. Many of these analyses have been presented before regulatory commissions in support of general rate case applications, and in particular in support of the revenue requirements in the applications. She has also developed equity management plans for electric cooperatives, pro forma and other financial analyses. Her financial project clients include:

- Golden Valley Electric Cooperative, Alaska
- Guam Power Authority, Guam
- Brownsville Public Utilities Board, Texas
- Kaua'i Island Utility Cooperative, Hawai'i
- City of Indianapolis, Indiana
- Lafayette Utilities System, Louisiana
- Georgetown Municipal Water and Server Service, Kentucky
- St. Joseph Power & Light, Missouri
- Homer Electric Association, Alaska
- CPS Energy, Texas

Depreciation

Ms. Tomczyk performs analyses on depreciation studies for municipal and cooperative utility clients. She developed a replacement planning model using survivor curve methodology to estimate the level of future replacement costs for electric utility systems at nine military bases that are operated and maintained under contract by City Light & Power, Inc. She has also been involved in the development of depreciation studies for the Kauai Island Utility Cooperative, Navajo Tribal Utility Authority, and Los Angeles Department of Water and Power. Ms. Tomczyk is a member of the Society of Depreciation Professionals (SDP) and has completed training courses offered by SDP. These training classes included topics such as data requirements and collection, unit versus group accounting, depreciation models, actuarial and simulation life analyses, salvage and cost of removal analyses, and technology forecasting. She is working towards becoming a Certified Depreciation Professional through SDP.

WORKSHOPS AND PRESENTATIONS

Ms. Tomczyk has served as an instructor on behalf of Electric Utility Consultants, Inc. (EUCI) for the following courses:

- Introduction to Cost of Service Concepts and Techniques for Electric Utilities
- Introduction to Rate Design for Electric Utilities

She has also made the following presentations at the Michigan Municipal Electric Association Annual Conference:

- Standby Rates for Distributed Generation
- Using AMI Data for Cost-of-Service and Rate Design Analyses, Resource Planning, and Financial Planning
- Balancing Aging Infrastructure, Rates, and Residential Demand

**Record of Testimony Submitted by
Laurie A. Tomczyk**

Utility	Proceeding	Subject of Testimony	Before	Client	Date
Richmond Power & Light	Cause No. 45361	Revenue Requirement	Indiana Utility Regulatory Commission	Richmond Power & Light	3/2020
Vectren Energy of Indiana	Docket No. 43354 – MCRA 21	MISO Cost and Revenue Adjustment Tracker	Indiana Utility Regulatory Commission	SABIC Innovative Plastics Mount Vernon, LLC	12/2017
El Paso Electric Company	Docket No. 46831	Cost of Service and Rate Design Studies	Public Utility Commission of Texas	U.S. Department of Defense and all other Federal Executive Agencies	06/2017 07/2017
Golden Valley Electric Association	Docket No. U-17-007	Revenue Requirement and Cost of Service Study and Transmission and Ancillary Service Rates Development	Regulatory Commission of Alaska	Golden Valley Electric Association	12/2016 08/2017
Homer Electric Association	Docket No. U-15-141	Revenue Requirement and Cost of Service Study and Transmission and Ancillary Service Rates Development	Regulatory Commission of Alaska	Homer Electric Association	10/2015 09/2016
Homer Electric Association	Docket No. U-13-203	Revenue Requirement and Cost of Service Study and Transmission and Ancillary Service Rates Development	Regulatory Commission of Alaska	Homer Electric Association	05/2014 06/2014 09/2014 02/2015
Homer Electric Association	Docket No. U-10-97	Revenue Requirement and Cost of Service Study	Regulatory Commission of Alaska	Homer Electric Association	10/2010
Chugach Electric Association	Docket No. U-09-80	Revenue Requirement and Cost of Service Study	Regulatory Commission of Alaska	Homer Electric Association	2/2010
Kaua‘i Island Utility Cooperative	Docket No. 2009-0050	Cost of Service Study and Standby Rate Development	Hawai‘i Public Utilities Commission	Kaua‘i Island Utility Cooperative	6/2009
Golden Valley Electric Association	Docket No. U-08-139	Cost of Service Study and Transmission and Ancillary Service Rates Development	Regulatory Commission of Alaska	Golden Valley Electric Association	9/2008
Chugach Electric Association	Docket No. U-06-134	Unbundled Financial Statements, Calculation of Equity, Patronage Capital Accruals, and Rate Impacts Due to New Generation	Regulatory Commission of Alaska	Homer Electric Association	3/2007

Document: 1989 Ind. PUC LEXIS 427

1989 Ind. PUC LEXIS 427

Copy Citation

Indiana Utility Regulatory Commission

December 13, 1989, Approved

CAUSE NO. **36835-S3**

Reporter

1989 Ind. PUC LEXIS 427 *

In the Matter of the Indiana Municipal Power Agency and the Indiana Cities and Towns, Members Thereof, to Modify, Simplify and Make More Equitable Certain Tracking Procedures Heretofore Authorized By This Commission to Track Increases or Decreases in the Cost of Purchased Power and Energy by Such Members From the Indiana Municipal Power Agency

Core Terms

track, energy, estimate, base rate, municipality, notice, retail

Panel: Monk, Bailey, Corban, O'Lessker and Zagrovich concur

Opinion By: Frederick L. Corban, Commissioner; Scott R. Jones, Assistant Chief Administrative Law Judge

Opinion

The Indiana cities and towns of Anderson, Bargersville, Centerville, Covington, Crawfordsville, Edinburgh, Flora, Frankfort, Frankton, Greendale, Greenfield, Lawrenceburg, Lebanon, Linton, Middletown, Paoli, Pendleton, Peru, Richmond, Rising Sun, Scottsburg, Tipton and Washington (collectively "the Petitioners") filed their petition instituting the above-captioned Cause on July 21, 1989. The petition seeks to modify the energy cost adjustment and power cost tracking procedures and forms approved by this Commission in its May 2, 1984 Order in Cause No. 36836-S2 and to authorize the Petitioners to use the modified procedures and forms in order to secure the Commission's approval of adjustments to their retail rates.

A hearing was held in this Cause at 9:30 A.M., EST, on December 1, 1989. Proper notice was provided as required by law, and the proofs of publication were incorporated into the record by reference. Petitioners and the Office of the Utility Consumer Counselor ("Public") appeared and participated at the hearing. No members of **[*2]** the general public appeared or participated.

During the hearing on December 1, 1989, Petitioners offered into evidence, without objection, the testimony of L. Gayle Mayo and Donald E. Gimbel as Petitioners' Exhibits LGM and DEG respectively. Petitioners also moved the Commission to take administrative notice of its October 27, 1982, January 11, 1983 and May 2, 1984 Orders in Cause Nos. 36835, 36835-S1 and 36835-S2 respectively. Petitioner's motion was granted and copies of the notice orders were received into the record of the proceedings in this Cause as part of Petitioners' case-in-chief. The report of the Commission's Engineering Staff, sponsored by Mr. Michael J. Mooney, was received into evidence pursuant to I.C. 8-1-1-5. No rebuttal evidence was offered by Petitioners.

Based upon the applicable law and the evidence herein, the Commission now finds:

1. Commission Jurisdiction and Notice. Due, legal and timely notice of the public hearing in this Cause was given and published as required by law. Each of the Petitioners is an Indiana municipality that operates an electric utility system distributing power and energy to industrial, commercial and residential customers **[*3]** and qualifies as a "municipally owned utility" as defined in I.C. 8-1-2-1. Petitioners are each subject to the jurisdiction of the Commission in the manner and to the extent allowed by the laws of the State of Indiana. The Commission has jurisdiction over the Petitioners and the subject matter of this proceeding.

2. Background Findings. Petitioners purchase their power and energy requirements from the Indiana Municipal Power Agency ("IMPA"). In Cause No. 36835, IMPA requested, in addition to other relief, that the Commission approve certain energy cost adjustment and power cost tracking procedures for use by its members that would allow each member to track to its retail customers increases or decreases in the cost of power and energy purchased from IMPA. As shown by the Commission's October 27, 1982 Order in Cause No. 36835, the Commission deferred action on IMPA's request, but created a subdocket (Cause No. 36835-S1) in order to fully explore the use of tracking procedures by IMPA's members.

After a public hearing, the Commission issued on January 11, 1983, its Order in Cause No. 36835-S1 in which it approved certain energy cost adjustment and power cost tracking procedures **[*4]** for use by IMPA's members and prescribed the use of certain forms reflecting those procedures. The Commission also ordered as part of its Order in Cause No. 36835-S1 that another subdocket (Cause No. 36835-S2) should be established for the purpose of reviewing and evaluating the tracking procedures approved in Cause No. 36835-S1.

After a hearing conducted on March 26, 1984, the Commission issued its Order in Cause No. 36835-S2 on May 2, 1984 and approved the use by IMPA's members of tracking procedures similar to those authorized by the Commission in Cause No. 36835-S1. The Commission also authorized the use of new forms reflecting the newly-approved procedures for the purpose of filing for retail rate adjustments. The new forms included some based on the "One-Part" forms previously approved by the Commission in Cause No. 36835-S1 and, for certain of IMPA's members that had the results of a reliable cost of service study and sufficient billing capability, completely new "Two-Part" forms. The Two-Part forms separate costs into demand and energy components and enable the IMPA members utilizing them to calculate retail rate adjustments for individual rate classes.

The Commission **[*5]** also found in its May 2, 1984 Order in Cause No. 35835-S2 that any municipality becoming a member of IMPA after the Order in Cause No. 36835-S1 could utilize the One-Part forms that had been approved by the Commission.

The primary purpose of the tracking procedures approved by the Commission for use by IMPA's members was to replace the fuel cost and wholesale power cost tracking procedures with procedures that allowed the energy cost adjustment charges portion of the costs billed by IMPA to its members to be appropriately reconciled on a quarterly basis. That purpose was accomplished under the procedures approved in Cause No. 36835-S2, which IMPA's members now have been using for over five years. However, as a result of their experience, Petitioners believe that the current procedures and forms need to be modified in order to make the use of tracking procedures by IMPA's members more effective and equitable. Accordingly, Petitioners are seeking in this Cause the Commission's approval of, and authorization to use, revised tracking procedures and forms. The revised forms, which reflect the specific procedures that Petitioners are seeking approval of in this Cause, were introduced **[*6]** into evidence with Ms. Mayo's testimony as Petitioners' Exhibits LGM-1 and LGM-2 and are attached hereto as Exhibits A and B. Exhibit A (LGM-1) is a revised One-Part form and Exhibit B (LGM-2) is a revised Two-Part form.

3. Additional Findings. Although formatted differently, the proposed forms generally provide for a continuation of the methodology and principles reflected in the forms currently in use by IMPA's members. However, the proposed forms treat changes in IMPA's base rates and capacity payments differently than the manner in which they are currently treated.

The present forms used by IMPA's members rely on prior year base rate changes to determine a total annual change in the base cost of purchased power. This method is not completely accurate because the total annual change is determined using previous year billing determinants and the resulting unit costs charges are then multiplied by an estimate of the next quarter's billing determinants. Under the proposed forms each of IMPA's members will calculate per unit changes between its current wholesale power costs and the wholesale power costs reflected in its current rates, and then multiply those changes by the **[*7]** next quarter's estimated billing determinants. This will result in the calculation of a truer change in the member's costs attributable to IMPA's base rates and lessen, but not eliminate by itself, the possibility that the member will overcollect or undercollect from its retail ratepayers.

To eliminate the possibility of overcollection or undercollection, the proposed forms include a base rate change reconciliation procedure under which each quarter's estimation of the billing determinants used by a member to bill its ratepayers is reconciled with the actual billing determinants used by IMPA to bill the member. Pursuant to the reconciliation procedure, the proposed forms require IMPA's members to take into consideration IMPA's base rates, together with IMPA's energy cost adjustment factor, in determining a quarterly variance between what the member billed its ratepayers and what IMPA billed the member resulting in a dollar for dollar flow through of IMPA's base rates and energy cost adjustment charges.

The proposed forms also reflect a change in regard to the capacity payments of IMPA members that have generating resources. The forms currently in use require an estimation of **[*8]** generating costs and payments for the entire year, beginning January 1, in September of the preceding year. This creates a sizable gap between the date of estimation and the final months of the estimated year. The proposed forms require the use of current estimates of member generating costs and payments from IMPA on a quarterly rather than on a yearly basis. This will also allow the affected IMPA members to more closely track changes in their costs from IMPA.

The data required to complete the proposed forms is very similar to that needed in connection with the present forms. Accordingly, it does not appear that the Petitioners, the Commission's Staff or the Office of the Utility Consumer Counselor will experience any great difficulties in connection with the use of the proposed forms in lieu of those currently in use.

All of the testimony and exhibits introduced in this Cause support, without reservation, the relief Petitioners are seeking.

4. Conclusion. The Commission finds the Petitioners' proposed forms, and the tracking procedures that they reflect, are fair, just, reasonable, adequate, non-discriminatory and do not grant any undue preference. Therefore, we find **[*9]** the proposed procedures and forms should be approved for use by Petitioners and all municipalities becoming members of IMPA after July 21, 1989, the date Petitioners filed their petition instituting this Cause.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION, that:

1. The energy cost adjustment and power cost tracking procedures that Petitioners have proposed and that are reflected in the forms attached hereto as Exhibit A and B are approved.

2. Petitioners and all municipalities becoming members of IMPA after July 21, 1989 shall be and are hereby authorized to use the forms attached hereto as Exhibits A and B in the manner allowed by the Commission's January 11, 1983 Order in Cause No. 36835-S1 and its May 2, 1984 Order in Cause No. 36835-S2.

3. The determination of which of the two sets of forms each of the Petitioners shall use shall continue to be governed by the provisions of the Commission's May 2, 1984 Order in Cause No. 36835-S2.

4. This Order shall be effective on and after the date of its approval.

EXHIBIT A [SEE ILLUSTRATION IN ORIGINAL]

EXHIBIT B [SEE ILLUSTRATION IN ORIGINAL]

Crawfordsville Electric Light & Power

P.O. Box 428 • 808 Lafayette Road • Crawfordsville, IN 47933
Phone (765) 362-1900 • Fax (765) 364-8224 • www.celp.com

125 YEARS OF SERVICE

August 17, 2020

<u>Via Electronic Filing – 30 Day Filings – Electric</u>

Mary Becerra
Commission Secretary
Indiana Utility Regulatory Commission
101 West Washington St., Suite 1500 E
Indianapolis, IN 46204

RE: Crawfordsville Electric Light & Power
30 Day Filing Pursuant to 170 IAC 1-6-1 et seq.

Dear Ms. Becerra:

Enclosed please find documents in support of our filing for a 30 Day Filing by Crawfordsville Electric Light & Power pursuant to 170 IAC Rule 6. The purpose of our filing is to implement an average change in the rates for electric service charged by its supplier, Indiana Municipal Power Agency. This request is allowable pursuant to 170 IAC 1-6-3 of Rule 6 because it entails Cause # 36835-2 dated 12-13-1989: a filing for which the commission has already approved or accepted the procedure for the change.

Affected customers have been notified as required under 170 IAC 1-6-6. Notice was published in the Journal Review on ____________________ . In addition, the Legal Notice has been placed on the utility website rates page (www.celp.com) and has been posted in a public place in the Crawfordsville Electric Light & Power customer service office(s). The contact information, including every person who may need to be contacted, regarding this request is:

Mr. Phillip R. Goode
765-362-1900
808 Lafayette Road
P.O. Box 428
Crawfordsville, IN 47933-0428
765/364-8224 (fax) philg@celp.com

The proposed rate adjustment will apply to electric customer bills during the three months of July, August, and September 2021. The average residential customer using 860 kWh will see a of approximately $0 or 0%.

Attached are the applicable tariff sheets and/or all working papers supporting this filing. I verify that notice has been provided as stated in this letter and that this letter and the attached documents are true and accurate to the best of my knowledge, information and belief. Please feel free to contact our office if there are any questions concerning any of the documents provided. Thank you for your assistance with this 30 Day Filing.

Yours truly,

Phillip R. Goode
Manager

Attachments

Crawfordsville Electric Light & Power

P.O. Box 428 • 808 Lafayette Road • Crawfordsville, IN 47933
Phone (765) 362-1900 • Fax (765) 364-8224 • www.celp.com
125 YEARS OF SERVICE

August 17, 2020

Mr. Brad Borum
Indiana Utility Regulatory Commission
Electricity Division
101 W Washington St., Suite 1500 East
Indianapolis, IN 46204-3407

TO THE INDIANA UTILITY REGULATORY COMMISSION

1. Crawfordsville Electric Light & Power, 808 Lafayette Rd., Crawfordsville, Indiana, under and pursuant to the Public Service Commission Act, as amended, and Commission Order in Cause No. 36835-S3, hereby files with the Indiana Regulatory Commission for its approval, changes in the schedule of rates for electricity sold as follows:

Residential Service	Decrease of:	$	-	per kWh
Gen. Power & Municipal Power	Decrease of:	$	-	per kW
	Decrease of:	$	-	per kWh
Primary Power Service	Decrease of:	$	-	per kVA
	Decrease of:	$	-	per kWh
Outdoor Lighting	Decrease of:	$	-	per kWh
Street Lighting	Decrease of:	$	-	per kWh
Traffic Lighting	Decrease of:	$	-	per kWh

2. The accompanying changes in the schedule of rates are based solely upon the changes in the cost of purchased power and energy, purchased by this utility computed in accordance with the Indiana Utility Regulatory Commission Order in Cause No. 36835-S3, dated December 13, 1989.

3. All of the matters and facts stated herein and in the attached exhibits are true and correct. If approved, this change of rate shall take effect for the bills to be rendered beginning with the July 2021 billing cycle.

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

BY:______________________________________
Phillip R. Goode

PRG/kc
Enclosure

STATE OF INDIANA)
) SS:
COUNTY OF MONTGOMERY)

Personally appeared before me, a Notary Public in and for said county and state, this __________ day of ________________2021, Phillip R. Goode, who after having been duly sworn according to law, stated that he or she is an officer of Crawfordsville Electric Light & Power, Crawfordsville, Indiana, that he or she has read the matters and facts stated above, and in all exhibits attached hereto, and that the same are true; that he or she is duly authorized to execute this instrument for and on behalf of the applicant herein.

____
Andrea McArthur
Notary Public
My County of Residence: Montgomery

My Commission Expires:
August 8, 2024

CRAWFORDSVILLE ELECTRIC LIGHT & POWER
Crawfordsville, Indiana

Proposed Rate Adjustment Applicable to the 3rd Quarter 2021
and Supporting Schedules

For use with rates approved under IURC Cause No. 44684
July, August, and September, 2021

LEGAL NOTICE

Crawfordsville Electric Light & Power has made a filing for a purchase power and energy tracking factor with the Indiana Utility Regulatory Commission in order to implement an average change in its rates for electric service charged by its supplier, Indiana Municipal Power Agency, pursuant to the Indiana Utility Regulatory Commission Order in Cause Number 36835-S3. The filing, if approved by the Commission, will be effective for energy consumed on or after the date of approval.

Rate RS	$	-	per kWh
Rate GP & MP	$	-	per kW
Rate GP & MP	$	-	per kWh
Rate PP	$	-	per kVA
Rate PP	$	-	per kWh
Rate OL	$	-	per kWh
Rate SL	$	-	per kWh
Rate TS	$	-	per kWh

Applicable: July, August and September, 2021

Any objection to this filing may be addressed to the following:

Indiana Office of Utility Consumer Counselor (OUCC)
115 W. Washington St., Suite 1500 South
Indianapolis, IN 46204
Toll Free: 1-888-441-2494
Voice/TDD: (317) 232-2494
Fax: (317) 232-5923
www.in.gov/iurc

Indiana Utility Regulatory Commission (IURC)
101 W. Washington St., Suite 1500 East
Indianapolis, IN 46204
Toll Free: 1-800-851-4268
Voice/TDD: (317) 232-2701
Fax: (317) 233-2410
www.in.gov/iurc

CRAWFORDSVILLE ELECTRIC LIGHT & POWER
Crawfordsville, Indiana

Appendix A

Rate Adjustments

The Rate Adjustments shall be on the basis of a Purchase Power Cost Adjustment Tracking Factor occasioned solely by changes in the cost of purchased power and energy, in accordance with the Order of the Indiana Utility Regulatory Commission, approved December 13, 1989 in Cause No. 36835-S3, as follows:

Rate Adjustments applicable to the below listed Rate Schedules are as follows:

Residential Service (RS)	$	-	per KWH
Gen. Power & Municipal Power (GP & MP)	$	-	per KW
	$	-	per KWH
Primary Power Service (PP)	$	-	per KVA
	$	-	per KWH
Outdoor Lighting (OL)	$	-	per KWH
Street Lighting (SL)	$	-	per KWH
Traffic Lighting (TS)	$	-	per KWH

Applicable: July, August and September, 2021

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

Crawfordsville, Indiana

Appendix B

Rate Adjustments applicable to the below listed Rate Schedules are as follows:

Residential Service	RS	$	-	per KWH
Gen. Power & Municipal Power	GP & MP	$	-	per KW
		$	-	per KWH
Primary Power Service	PP	$	-	per KVA
		$	-	per KWH
Outdoor Lighting	OL	$	-	per KWH
Street Lighting	SL	$	-	per KWH
Traffic Lighting	TS	$	-	per KWH

Average Change in Schedule of Rates:

Residential Service	RS	Decrease	$	-	per KWH
Gen. Power & Municipal Power	GP & MP	Decrease	$	-	per KW
		Decrease	$	-	per KWH
Primary Power Service	PP	Decrease	$	-	per KVA
		Decrease	$	-	per KWH
Outdoor Lighting	OL	Decrease	$	-	per KWH
Street Lighting	SL	Decrease	$	-	per KWH
Traffic Lighting	TS	Decrease	$	-	per KWH

Applicable: July, August and September, 2021

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

DETERMINATION OF INCREMENTAL CHANGE IN BASE RATE

LINE NO.	DESCRIPTION			DEMAND RELATED	ENERGY RELATED	LINE NO.
1	BASE RATE EFFECTIVE	01-Jan-21	(a)	$26.217	$0.028875	1
2	BASE RATE EFFECTIVE	01-Jan-20	(b)	$22.957	$0.026390	2
3	INCREMENTAL CHANGE IN BASE RATE (c)			$3.260	$0.002485	3

(a) IMPA rate effective for the period covered by this filing. The Base Rate includes the applicable Delivery Voltage Adjustment.
(b) Base purchased power rate including Voltage Adjustment effective at the time of the member's last approved rate case was filed or January 27, 1983, whichever is more recent.
(c) Line 1 - Line 2

Exhibit II

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

ESTIMATION OF SAVINGS FROM DEDICATED CAPACITY PAYMENTS
FOR THE THREE MONTHS OF:

Jul-21 Aug-21 Sep-21

LINE NO.	DESCRIPTION	DEMAND RELATED		LINE NO.
1	ESTIMATED MONTHLY GENERATING COSTS (h)	$0.00		1
2	LESS: MONTHLY GEN COSTS IN BASE RATES (i)	$0.00		2
3	EST GENERATING COSTS IN TRACKER (a)	$0.00		3
4	EST MONTHLY PAYMENT FROM IMPA (f)	$0.00		4
5	LESS: MONTHLY PAYMENTS IN BASE RATES (g)	$0.00		5
6	EST CAPACITY PAYMENTS IN TRACKER (b)	$0.00	NOT APPLICABLE	6
7	ESTIMATED MONTHLY COSTS/(SAVINGS) (c)	$0.00		7
8	ESTIMATED AVERAGE MONTHLY KW (d)	69,938		8
9	ESTIMATED COSTS/(SAVINGS) PER KW (e)	$0.0000		9

Note: The CEL&P Plant was sold as of 12/30/2013 - No cost is estimated for this quarter.
Approved as part of last CEL&P IURC Rate Case Cause #43773 dated 7/28/10.
(a) Line 1 - Line 2
(b) Line 4 - Line 5
(c) Line 3 - Line 6 Times The Number Of Years Since Last Cost Of Service Study
(d) Exhibit III, Column E, Line 1
(e) Line 7 divided by Line 8
(f) Capacity Payments Forecasted by Indiana Municipal Power Agency
(g) Average capacity payments for 12 months ending Month/Year
(h) Estimated Generating Costs (CEL&P no longer receives monthly payment.)
(i) Average generating cost for 12 months ending Month/Year

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

ESTIMATION OF ENERGY COST ADJUSTMENT
FOR THE THREE MONTHS OF:

Jul-21 Aug-21 Sep-21

LINE NO.	DESCRIPTION	Jul-21 (A)	Aug-21 (B)	Sep-21 (C)	TOTAL (D)	ESTIMATED 3 MONTH AVERAGE (E)	LINE NO.
	PURCHASED POWER FROM IMPA						
1	KW DEMAND	72,847	66,600	70,367	209,814	69,938	1
2	KWH ENERGY	40,201,261	37,570,660	34,754,299	112,526,220	37,508,740	2
	INCREMENTAL PURCHASED POWER COSTS						
	DEMAND RELATED						
3	ECA FACTOR PER KW	(3.260)	(3.260)	(3.260)		(3.260)	3
4	CHARGE (a)	($237,481.22)	($217,116.00)	($229,396.42)	($683,993.64)	($227,997.88)	4
	ENERGY RELATED						
5	ECA FACTOR PER KWH	(0.002485)	(0.002485)	(0.002485)		(0.002485)	5
6	CHARGE (b)	($99,900.13)	($93,363.09)	($86,364.43)	($279,627.66)	($93,209.22)	6

(a) Line 1 times Line 3
(b) Line 2 times Line 5

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

DETERMINATION OF DEMAND RATE ADJUSTMENT FOR RATE SCHEDULE PP
For the Three Months of: July, August, and September
2021

LINE NO.	Demand Related Adjustment Factors					LINE NO.
	Rate PP					
1	From Attachment B, Page 3 of 3, Column C, Line 3			$0.00		1
2	From Attachment B, Page 2 of 3, Column C, Line 3			44,587.50	kW	2
3	LIne 1 divided by Line 2		$	-		3
4	Line 3 multiplied by	85.601% *	$	-		4
5	**Demand Related Rate Adjustment Factor**		**$**	**-**	per KVA	5

* Average Power Factor of the PP class.

	Rate GP & MP				
1	From Page 3 of 3, Column C, Line 2			$0.00	
2	From Page 2 of 3, Column C, Line 2			9,205.10	kW
3	LIne 1 divided by Line 2		$	-	
4	Line 3 multiplied by	48.102% *	$	-	
5	Demand Related Rate Adjustment Factor		**$**	**-**	per KW

* Average Power Factor of the GP & MP classes.

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

DETERMINATION OF RATE ADJUSTMENT FOR THE
THREE MONTHS OF
Jul-21 Aug-21 Sep-21

LINE NO.	DESCRIPTION	DEMAND RELATED (A)	ENERGY RELATED (B)	LINE NO.
1	INCREMENTAL CHANGE IN BASE RATE (a)	$3.260	$0.002485	1
2	ESTIMATED SAVINGS (LOSS) FROM DEDICATED CAPACITY PAYMENTS (b)	$0.000	--	2
3	ESTIMATED PURCHASED POWER ENERGY COST ADJUSTMENT (c)	($3.260)	-$0.002485	3
4	ESTIMATED TOTAL CHANGE IN PURCHASED POWER RATE	$0.000	$0.000000	4
5	EST CHANGE IN PURCHASED POWER RATE ADJ FOR LOSSES & GR INCOME TAX (d)	$0.0000	$0.000000	5
6	PLUS TRACKING FACTOR EFFECTIVE PRIOR TO JANUARY 27, 1983 (e)	$0.000	$0.000000	6
7	ESTIMATED TOTAL RATE ADJUSTMENT	$0.000	$0.000000	7
8	ESTIMATED AVERAGE BILLING UNITS (f)	69,938	37,508,740	8
9	ESTIMATED INCREMENTAL CHANGE IN PURCHASED POWER COST (g)	$0.00	$0.00	9

(a) Exhibit I, Line 3
(b) Exhibit II, Line 9
(c) Exhibit III, Column E, Lines 3 and 5
(d) Line 4 divided by (1 - line loss factor)(0.986) = 0.9555326
(e) Tracking Factor effective prior to January 27, 1983. This factor is zero if new rates have been filed and approved since January 27, 1983.
(f) Exhibit III, Column E, Lines 1 and 2
(g) Line 7 times Line 8

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

DETERMINATION OF RATE ADJUSTMENT FOR THE
THREE MONTHS OF:

				Jul-21	Aug-21	Sep-21			
LINE NO.	RATE SCHEDULE	KW DEMAND ALLOCATOR (%) (a)	KWH ENERGY ALLOCATOR (%) (a)	ALLOCATED ESTIMATED KW PURCHASED (b)	ALLOCATED ESTIMATED KWH PURCHASED (c)	INCREMENTAL CHANGE IN PURCHASED POWER COST ADJ FOR LINE LOSSES & GROSS RECEIPTS TAX DEMAND (d)	ENERGY (e)	TOTAL	LINE NO.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	
1	RS	23.059%	21.684%	16,127.3	8,133,221	$0.00	$0.00	$0.00	1
2	GP & MP	13.162%	11.576%	9,205.1	4,342,133	$0.00	$0.00	$0.00	2
3	PP	63.753%	66.127%	44,587.5	24,803,332	$0.00	$0.00	$0.00	3
4		0.000%	0.000%	0.0	0	$0.00	$0.00	$0.00	4
5	OL	0.000%	0.273%	0.0	102,476	$0.00	$0.00	$0.00	5
6	SL	0.000%	0.307%	0.0	114,975	$0.00	$0.00	$0.00	6
7		0.000%	0.000%	0.0	0	$0.00	$0.00	$0.00	7
8		0.000%	0.000%	0.0	0	$0.00	$0.00	$0.00	8
9	TS	0.026%	0.034%	18.1	12,603	$0.00	$0.00	$0.00	9
10		0.000%	0.000%	0.0	0	$0.00	$0.00	$0.00	10
11									
12	TOTAL	100.000%	100.000%	69,938.0	37,508,740	$0.00	$0.00	$0.00	13

(a) Taken From Exhibit VI.
(b) Page 1 of 3, Column A, Line 8 times Page 2 of 3, Column A
(c) Page 1 of 3, Column B, Line 8 times Page 2 of 3, Column B
(d) Page 1 of 3, Column A, Line 9 times Page 2 of 3, Column A
(e) Page 1 of 3, Column B, Line 9 times Page 2 of 3, Column B

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

DETERMINATION OF RATE ADJUSTMENT FOR THE
THREE MONTHS OF:

Jul-21 Aug-21 Sep-21

LINE	RATE	PLUS VARIANCE (a)		TOTAL CHANGE IN PURCHASED POWER COST ADJ FOR LINE LOSSES & GROSS RECEIPTS TAX			RATE ADJUSTMENT FACTOR PER KWH (d)			LINE
NO.	SCHEDULE	DEMAND	ENERGY	DEMAND (b)	ENERGY (c)	TOTAL	DEMAND	ENERGY	TOTAL	NO.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
1	RS	$0.00	$0.00	$0.00	$0.00	$0.00	0.000000	0.000000	0.000000	1
2	GP & MP	$0.00	$0.00	$0.00	$0.00	$0.00	0.000000	0.000000	0.000000	2
3	PP	$0.00	$0.00	$0.00	$0.00	$0.00	0.000000	0.000000	0.000000	3
4		$0.00	$0.00	$0.00	$0.00	$0.00	0.000000	0.000000	0.000000	4
5	OL	$0.00	$0.00	$0.00	$0.00	$0.00	0.000000	0.000000	0.000000	5
6	SL	$0.00	$0.00	$0.00	$0.00	$0.00	0.000000	0.000000	0.000000	
7		$0.00	$0.00	$0.00	$0.00	$0.00	0.000000	0.000000	0.000000	6
8		$0.00	$0.00	$0.00	$0.00	$0.00	0.000000	0.000000	0.000000	7
9	TS	$0.00	$0.00	$0.00	$0.00	$0.00	0.000000	0.000000	0.000000	
10		$0.00	$0.00	$0.00	$0.00	$0.00	0.000000	0.000000	0.000000	
11										
12	TOTAL	$0.00	$0.00	$0.00	$0.00	$0.00	0.000000	0.000000	0.000000	10

(a) Exhibit IV, Page 4 of 7, Columns D and E divided by (1 - loss factor)(.986) = 0.9555326
(b) Page 2 of 3, Column E plus Page 3 of 3, Column A
(c) Page 2 of 3, Column F plus Page 3 of 3, Column B
(d) Page 3 of 3, Columns C, D and E divided by Page 2 of 3, Column D

(f) See Attachment (B)

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

RECONCILIATION OF VARIANCES FOR THE
THREE MONTHS OF

Jan-21 Feb-21 Mar-21

LINE NO.	DESCRIPTION	DEMAND RELATED (A)	ENERGY RELATED (B)	LINE NO.
1	INCREMENTAL CHANGE IN BASE RATE (a)	$3.260	$0.002485	1
2	ACTUAL SAVINGS FROM DEDICATED CAPACITY PAYMENTS (b)	$0.000	--	2
3	ACTUAL PURCHASED POWER ENERGY COST ADJUSTMENT (c)	($3.260)	($0.002485)	3
4	TOTAL RATE ADJUSTMENT (d)	$0.000	$0.000000	4
5	ACTUAL AVERAGE BILLING UNITS (e)	55,495	32,679,935	5
6	ACTUAL INCREMENTAL CHANGE IN PURCHASED POWER COST (f)	$0.00	$0.00	6

(a) Attachment 1, Page 1 of 3, Line 1 of Tracker filing for the three months of:
Jan-21 Feb-21 Mar-21

(b) Exhibit IV, Page 5 of 7, Column E, Line 9
(c) Exhibit IV, Page 6 of 7, Column E, Lines 3 and 5
(d) Sum of Lines 1 through 4
(e) Exhibit IV, Page 6 of 7, Column E, Lines 1 and 2
(f) Line 5 times Line 6

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

RECONCILIATION OF VARIANCES FOR THE
THREE MONTHS OF:

Jan-21 Feb-21 Mar-21

LINE NO.	RATE SCHEDULE	KW DEMAND ALLOCATOR (%) (a)	KWH ENERGY ALLOCATOR (%) (a)	ALLOCATED ACTUAL KW PURCHASED (b)	ALLOCATED ACTUAL KWH PURCHASED (c)	INCREMENTAL CHANGE IN PURCHASED POWER COST DEMAND (d)	ENERGY (e)	TOTAL	LINE NO.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	
1	RS	23.059%	21.684%	12,796.9	7,086,165	$0.00	$0.00	$0.00	1
2	GP & MP	13.162%	11.576%	7,304.2	3,783,135	$0.00	$0.00	$0.00	2
3	PP	63.753%	66.127%	35,379.6	21,610,197	$0.00	$0.00	$0.00	3
4		0.000%	0.000%	0.0	0	$0.00	$0.00	$0.00	4
5	OL	0.000%	0.273%	0.0	89,283	$0.00	$0.00	$0.00	5
6	SL	0.000%	0.307%	0.0	100,174	$0.00	$0.00	$0.00	6
7		0.000%	0.000%	0.0	0	$0.00	$0.00	$0.00	7
8		0.000%	0.000%	0.0	0	$0.00	$0.00	$0.00	8
9	TS	0.026%	0.034%	14.3	10,981	$0.00	$0.00	$0.00	9
10		0.000%	0.000%	0.0	0	$0.00	$0.00	$0.00	10
11									11
12	TOTAL	100.000%	100.000%	55,495.0	32,679,935	$0.00	$0.00	$0.00	12

(a) Adjusted allocators from Exhibit VI Rows (14) and (19) for the year o 2021
(b) Exhibit IV, Page 6 of 7, Column E, Line 1 times Exhibit IV, Page 2 of 7, Column A
(c) Exhibit IV, Page 6 of 7, Column E, Line 2 times Exhibit IV, Page 2 of 7, Column B
(d) Exhibit IV, Page 1 of 7, Column A, Line 7 times Exhibit IV, Page 2 of 7, Column A
(e) Exhibit IV, Page 1 of 7, Column B, Line 7 times Exhibit IV, Page 2 of 7, Column B

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

RECONCILIATION OF VARIANCES FOR THE
THREE MONTHS OF:

Jan-21 Feb-21 Mar-21

LINE NO.	RATE SCHEDULE	ACTUAL AVERAGE KWH SALES (a)	ACTUAL AVERAGE KW/KVA SALES (a)	DEMAND ADJUSTMENT FACTOR PER KWH (b)	ENERGY ADJUSTMENT FACTOR PER KWH (c)	INCREMENTAL KW DEMAND COST BILLED BY MEMBER (d)	INCREMENTAL KWH ENERGY COST BILLED BY MEMBER (e)	LESS PREVIOUS VARIANCE FOR MONTHS LISTED ABOVE DEMAND (f)	LESS PREVIOUS VARIANCE FOR MONTHS LISTED ABOVE ENERGY (g)	LINE NO.
		(A)	(A)	(B)	(C)	(D)	(E)	(F)	(G)	
1	RS	7,391,231	-	0.000000	0.000000	$0.00	$0.00	$0.00	$0.00	1
2	GP & MP	3,662,161	14,509.23	0.000000	0.000000	$0.00	$0.00	$0.00	$0.00	2
3	PP	20,387,011	39,050.99	0.000000	0.000000	$0.00	$0.00	$0.00	$0.00	3
4		0	-	0.000000	0.000000	$0.00	$0.00	$0.00	$0.00	4
5	OL	94,279	-	0.000000	0.000000	$0.00	$0.00	$0.00	$0.00	5
6	SL	104,844	-	0.000000	0.000000	$0.00	$0.00	$0.00	$0.00	6
7		0	-	0.000000	0.000000	$0.00	$0.00	$0.00	$0.00	7
8		0	-	0.000000	0.000000	$0.00	$0.00	$0.00	$0.00	8
9	TS	10,942	-	0.000000	0.000000	$0.00	$0.00	$0.00	$0.00	9
10		0	-	0.000000	0.000000	$0.00	$0.00	$0.00	$0.00	10
11										11
12	TOTAL	31,650,468	53,560			$0.00	$0.00	$0.00	$0.00	12

(a) Exhibit IV, Page 7 of 7, Column E			
(b) Page 3 of 3, Column F of Tracker Filing for the three months of:	Jan-21	Feb-21	Mar-21
(c) Page 3 of 3, Column G of Tracker Filing for the three months of:	Jan-21	Feb-21	Mar-21
(d) Column A times Column B times the Gross Income Tax Factor of:	0.986		
(e) Column A times Column C times the Gross Income Tax Factor of:	0.986		
(f) Exhibit IV, Page 4 of 7, Column D of Tracker Filing for the months of:	Jan-21	Feb-21	Mar-21
(g) Exhibit IV, Page 4 of 7, Column E of Tracker Filing for the months of :	Jan-21	Feb-21	Mar-21

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

RECONCILIATION OF VARIANCES FOR THE
THREE MONTHS OF:

Jan-21 Feb-21 Mar-21

LINE NO.	RATE SCHEDULE	NET INCREMENTAL COST BILLED BY MEMBER DEMAND (a)	ENERGY (b)	TOTAL	VARIANCE DEMAND (c)	ENERGY (c)	TOTAL (c)	LINE NO.
		(A)	(B)	(C)	(D)	(E)	(F)	
1	RS	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	1
2	GP & MP	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	2
3	PP	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	3
4		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	4
5	OL	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	5
6	SL	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	6
7		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	7
8		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	8
9	TS	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	9
10		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	10
11								11
12	TOTAL	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	12

(a) Column D minus Column F from Exhibit IV, page 3 of 7
(b) Column E minus Column G from Exhibit IV, Page 3 of 7
(c) Columns E, F, and G from Exhibit IV, Page 2 of 7 minus Columns A, B, and C

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

DETERMINATION OF ACTUAL DEDICATED CAPACITY PAYMENTS
FOR THE THREE MONTHS OF

LINE NO.	DESCRIPTION	Jan-21 January (A)	Feb-21 February (B)	Mar-21 March (C)	TOTAL (D)	AVERAGE (E)	LINE NO.
1	ACTUAL MEMBER GENERATING COSTS	$0.00	$0.00	$0.00	$0.00	$0.00	1
2	LESS: GENERATING COSTS IN BASE RATES	$0.00	$0.00	$0.00	$0.00	$0.00	2
3	DIFFERENCE IN ACTUAL TO BASE RATE COSTS (a)	$0.00	$0.00	$0.00	$0.00	$0.00	3
4	ACTUAL MONTHLY PAYMENT FROM IMPA	$0.00	$0.00	$0.00	$0.00	$0.00	4
5	LESS: ESTIMATED PAYMENT IN BASE RATES (f)	$0.00	$0.00	$0.00	$0.00	$0.00	5
6	DIFFERENCE IN ACTUAL TO BASE RATE PAYMENT (b)	$0.00	$0.00	$0.00	$0.00	$0.00	6
7	ACTUAL CAPACITY PAYMENT SAVINGS TO BE COLLECTED THROUGH THE TRACKER (c)	$0.00	$0.00	$0.00	$0.00	$0.00	7
8	ACTUAL MONTHLY KW BILLED (d)	52,951	56,942	56,591	166,484	55,495	8
9	ACTUAL CAPACITY PAYMENT SAVINGS PER KW (e)	$0.000	$0.000	$0.000		$0.000	9

(a) Line 1 minus Line 2
(b) Line 4 minus Line 5
(c) Line 3 minus Line 6
(d) Exhibit IV, Page 6 of 7, Line 1
(e) Line 7 divided by Line 8
(f) Exhibit II, Line 5

NOTE: This exhibit is only applicable to a municipal utility with generation.

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

DETERMINATION OF ACTUAL ENERGY COST ADJUSTMENT
FROM HISTORICAL DATA

LINE NO.	DESCRIPTION	Jan-21	Feb-21	Mar-21	TOTAL	ACTUAL 3 MONTH AVERAGE	LINE NO.
		(A)	(B)	(C)	(D)	(E)	
	PURCHASED POWER FROM IMPA						
1	KW DEMAND (a)	52,951	56,942	56,591	166,484	55,495	1
2	KWH ENERGY (a)	33,149,838	31,186,070	33,703,898	98,039,806	32,679,935	2
	INCREMENTAL PURCHASED POWER COSTS						
	DEMAND RELATED						
3	ECA FACTOR PER KW (a)	(3.260)	(3.260)	(3.260)		(3.260)	3
4	CHARGE (b)	($172,620.26)	($185,630.92)	($184,486.66)	($542,737.84)	($180,912.61)	4
	ENERGY RELATED						
5	ECA FACTOR PER KWH (a)	(0.002485)	(0.002485)	(0.002485)		(0.002485)	5
6	CHARGE (c)	($82,377.35)	($77,497.38)	($83,754.19)	($243,628.92)	($81,209.64)	6

(a) From IMPA bills for the months of: Jan-21 Feb-21 Mar-21
(b) Line 1 times Line 3
(c) Line 2 times Line 5

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

DETERMINATION OF ACTUAL AVERAGE KWH SALES
HISTORICAL DATA

LINE NO.	RATE SCHEDULE	Jan-21 (A)	Feb-21 (B)	Mar-21 (C)	TOTAL (D)	AVERAGE (E)	LINE NO.
1	RS	7,668,254	7,560,899	6,944,541	22,173,693	7,391,231	1
2	GP & MP	3,692,322	3,726,251	3,567,911	10,986,484	3,662,161	2
3	PP	19,941,742	20,532,915	20,686,376	61,161,033	20,387,011	3
4		0	0	0	0	0	4
5	OL	102,209	93,353	87,274	282,836	94,279	5
6	SL	113,798	104,201	96,533	314,531	104,844	6
7		0	0	0	0	0	7
8		0	0	0	0	0	8
9	TS	10,855	10,942	11,029	32,826	10,942	9
10		0	0	0	0	0	10
11							11
12	TOTAL	31,529,178	32,028,560	31,393,664	94,951,402	31,650,468	12

DETERMINATION OF ACTUAL AVERAGE KW/KVA SALES

			Jan-21	Feb-21	Mar-21	TOTAL	AVERAGE	
13			0	0	0	0	0	13
14	GP & MP	NCP	14,197	15,133	14,197	43,528	14,509	14
15	PP	NCP	38,896	38,760	39,497	117,153	39,051	15
16			0	0	0	0	0	16
17			0	0	0	0	0	17
18			0	0	0	0	0	18
19			0	0	0	0	0	19
20			0	0	0	0	0	20
21			0	0	0	0	0	21
22								22
23			53,093	53,893	53,695	160,681	53,560	23

Exhibit V

CRAWFORDSVILLE ELECTRIC LIGHT & POWER
Crawfordsville, Indiana

CALCULATION OF LINE LOSS FACTOR
FOR YEAR 2020

Month	Metered kWh Sold	IMPA Metered kWh Purchased
January	31,529,178	32,548,586
February	32,028,560	33,059,558
March	31,393,664	32,394,951
April	30,164,659	31,109,007
May	30,730,011	31,683,379
June	33,108,948	34,151,934
July	36,244,385	37,412,522
August	37,943,318	39,166,259
September	35,057,150	36,172,559
October	31,012,400	31,990,525
November	30,171,855	31,130,179
December	30,868,358	31,864,892
Subtotal	390,252,486	402,684,350
Other Adjustments (ie Unmetered sales)	0	0
Total	390,252,486	402,684,350
Estimated Losses kWh		12,431,864
Line Loss as percent of total purchases		3.09%

Exhibit VI

CRAWFORDSVILLE ELECTRIC LIGHT & POWER

Crawfordsville, Indiana

VERIFICATION FOR FUTURE USE OF KW DEMAND ALLOCATION AND KWH ENERGY ALLOCATION FACTORS IN COMPLIANCE WITH ORDERING PARAGRAPH 7 OF IURC CAUSE NO. 36835-S2, DATED MAY 2, 1984

Line No.	Month		Residential Service RS (A)	Municipal Power GP & MP (B)	Primary Power Service PP (C)	- (D)	Outdoor Lighting OL (E)	Street Lighting SL (F)	Traffic Lighting TS (G)	Total (H)
1	January		7,668,254	3,692,322	19,941,742		102,209	113,798	10,855	31,529,178
2	February		7,560,899	3,726,251	20,532,915		93,353	104,201	10,942	32,028,560
3	March		6,944,541	3,567,911	20,686,376		87,274	96,533	11,029	31,393,664
4	April		5,749,083	3,298,796	20,948,710		74,086	82,956	11,029	30,164,659
5	May		5,378,033	3,337,576	21,865,921		64,751	72,702	11,029	30,730,011
6	June		6,625,670	3,734,936	22,602,930		63,017	71,367	11,029	33,108,948
7	July		8,620,469	4,310,750	23,149,108		71,692	81,425	10,942	36,244,385
8	August		8,946,398	4,580,387	24,231,279		81,747	92,653	10,855	37,943,318
9	September		7,427,579	4,153,421	23,264,932		93,936	106,429	10,855	35,057,150
10	October		6,072,795	3,605,219	21,100,072		104,724	118,736	10,855	31,012,400
11	November		6,271,392	3,526,467	20,122,673		113,235	127,234	10,855	30,171,855
12	December		7,355,422	3,642,857	19,614,847		116,170	128,208	10,855	30,868,358
13	Total		84,620,532	45,176,890	258,061,505	0	1,066,191	1,196,238	131,130	390,252,486
14	Percent of Total	(b)	**21.684%**	**11.576%**	**66.127%**	**0.000%**	**0.273%**	**0.307%**	**0.034%**	**100.000%**
15	kWh Energy Factors	(a)	21.634%	11.550%	66.204%	0.000%	0.273%	0.306%	0.034%	**100.0000%**
16	Percent Variance	{c}	0.228%	0.228%	-0.116%	0.000%	0.228%	0.228%	0.228%	
17	kW Demand Factors	(a)	23.009%	13.133%	63.832%	0.000%	0.000%	0.000%	0.026%	100.0000%
18	Adjusted Factors	(d)	23.061%	13.163%	63.758%	0.000%	0.000%	0.000%	0.026%	100.008%
19	Percent of Total	(e)	**23.059%**	**13.162%**	**63.753%**	**0.000%**	**0.000%**	**0.000%**	**0.026%**	**100.000%**

(a) Taken from Cost of Service Study based on Twelve Month Period ending February 28,2020.
(b) kWh sales by rate classification expressed as a percent of total kWH sales for the year 2018. Proposed kWh Energy allocator for year 2019.
{c} (Line 14/ Line 15)-1.
(d) (1+ Line 16) * Line 17.
(e) (Line 18) / (Line 18, column H). Proposed kW Demand allocator for year 2021.

General Inputs Trackers for **CRAWFORDSVILLE ELECTRIC LIGHT & POWER**

Enter data only in cells with yellow shading.
Please date entries where requested.

Name of Utility:	
Crawfordsville Electric Light & Power	
Location:	
Crawfordsville, Indiana	3rd Quarter 2021

Initial month for the projected period	Jul-21	Aug-21	Sep-21
Historical period for this analysis	Jan-21	Feb-21	Mar-21

IMPA rate for the period covered by this analysis: Entered: 8/10/2020
Effective for: 1/1/2021

	Demand $/kW		Energy $/kWh	
Base Production	$ 26.217		$ 0.028875	
Delivery Voltage	$ -			
Total	$ 26.217		$ 0.028875	
Capacity Payment (Annual)		$ -	$ -	Average

Rate effective for the **BASE** period (Rate Study) Entered: 8/10/2020
effective for 1/1/2020

	Demand $/kW	Energy $/kWh
Base Production	$ 26.217	$ 0.028875
Delivery Voltage		
ECA	$ (3.260)	-0.002485
	22.957	0.026390
	3.260	0.002485

Generation Costs & Capacity Payments Entered: 4/29/2016
From most recent Electric Rate Study

	Generation Costs in Base Rates	Capacity Payments in Base Rates
Inc Change Base Rate	$ -	$ -

Data from IMPA Entered: 4/13/2021
Estimated Purchased Power from IMPA

	kW Jul-21	kW Aug-21	kW Sep-21	kWh Jul-21	kWh Aug-21	kWh Sep-21
	72,847	66,600	70,367	40,201,261	37,570,660	34,754,299
Total Billing Determinants		209,814 kW			112,526,220 kWh	
	Demand ECA - $/kW			Energy ECA - $/kWh		
IMPA ECA	($3.260)	($3.260)	($3.260)	($0.002485)	($0.002485)	($0.002485)

Data from IMPA's Bills Entered: 4/15/2021

Month of Service	Jan-21	Feb-21	Mar-21	Total Billing Determinants Sum	Average
Demand (kW)	52,951	56,942	56,591	166,484	55,495
Energy (kWh)	33,149,838	31,186,070	33,703,898	98,039,806	32,679,935
Energy Cost Adjustment (ECA)					
Demand, $/kW	($3.260)	($3.260)	($3.260)		
Energy, $/kWh	($0.002485)	($0.002485)	($0.002485)		
Capacity Payments Less Fuel	$ -	$ -	$ -	$ -	$ -

Incremental Change in Base Rate Entered: 4/15/2021
from Attachment "B", page 1 of 3, line 1
for the months of: Jan-21 Feb-21 Mar-21

	Demand Related $/kVA	Energy Related $/kWh
Incremental Change in Base Rates	3.260	0.002485

Rate Tariffs
Note: Once all rate codes are entered, put N/A in remaining blanks (Col A)

Code	Name/Description	Demand billed on basis of Coincident Pk?	Is Demand billed on NCP Peak? ("1" = yes, "0" = no)	Is delivery at transmission v	Is this a flat rate?	Does a Tracker apply to this rate?
RS	Residential Service					1
GP & MP	Gen. Power & Municipal Power		1			1
PP	Primary Power Service		1			1
OL	Outdoor Lighting				1	1
SL	Street Lighting				1	1
TS	Traffic Lighting				1	1

Adjustment Factors (per kWh) — Entered: 4/15/2021

Copy from Attachment B, Page 3 of 3, of Tracker calculation for the billing periods of: Jan-21 Feb-21 Mar-21

	Code	Name/Description	Factor per kW/kVA: Demand (Att. A Column G)	Factor per kWh: Demand (copy from Column F)	Factor per kWh: Energy (copy from Column G)	Total (to verify)
1	RS	Residential Service	0.000000	0.000000	0.000000	0.000000
2	GP & MP	Gen. Power & Municipal Power	0.000000	0.000000	0.000000	0.000000
3	PP	Primary Power Service	0.000000	0.000000	0.000000	0.000000
4			0.000000	0.000000	0.000000	0.000000
5	OL	Outdoor Lighting	0.000000	0.000000	0.000000	0.000000
6	SL	Street Lighting	0.000000	0.000000	0.000000	0.000000
7	0	0	0.000000	0.000000	0.000000	0.000000
8	0	0	0.000000	0.000000	0.000000	0.000000
9	TS	Traffic Lighting	0.000000	0.000000	0.000000	0.000000
10	0	0	0.000000	0.000000	0.000000	0.000000
11						
12	Total			0.000000	0.000000	0.000000

Allocation Factors — Entered: 8/10/20

from 2020 Rate Study

Code	Name/Description	Factors for New Rates: kW Demand Factors	kWh Energy Factors	Power Factors
RS	Residential Service	23.009%	21.634%	
GP & MP	Gen. Power & Municipal Power	13.133%	11.550%	48.102%
PP	Primary Power Service	63.832%	66.204%	85.601%
0	0	0.000%	0.000%	
OL	Outdoor Lighting	0.000%	0.273%	
SL	Street Lighting	0.000%	0.306%	
0	0	0.000%	0.000%	
0	0	0.000%	0.000%	
TS	Traffic Lighting	0.026%	0.034%	
0	0	0.000%	0.000%	
		100.000%	100.000%	

Indiana Utility Receipts Tax

Tax Rate	1.40%
Tax Factor	0.9860

		3/1/2021
Distribution Loss Factor: (From Exhibit V)	3.09%	

Residential Rate Data — 8/10/20

Usage (kWh): 860

	Current Rate	Last Quarter	This Quarter	$ Change	% Change
Customer Cha	$ 15.00	$ 15.00	$ 15.00		
Energy, All kW	$ 0.097405	$ 83.77	$ 83.77		
Last Quarter	$ -	$ -			
This Quarter	$ -		$ -		
		$ 98.77	$ 98.77	$ (0.00)	0.0%

Data for Loss Calculation — Entered: 1/25/2021

Calendar Yr 2020	Retail Sales	Purchased Power	Line Loss
January	31,529,178	32,548,586	3.13%
February	32,028,560	33,059,558	3.12%
March	31,393,664	32,394,951	3.09%
April*	30,164,659	31,109,007	3.04%
May	30,730,011	31,683,379	3.01%
June	33,108,948	34,151,934	3.05%
July	36,244,385	37,412,522	3.12%
August	37,943,318	39,166,259	3.12%
September	35,057,150	36,172,559	3.08%
October	31,012,400	31,990,525	3.06%
November	30,171,855	31,130,179	3.08%
December	30,868,358	31,864,892	3.13%
SubTotal	390,252,486	402,684,350	3.09%
Unmetered Sales	-		
Total	390,252,486	402,684,350	3.09%

** Billing period realignment, meter read dates shifted.*

Previous Variance — Entered: 4/15/2021

Copy from Exhibit IV, Page 4 of 7 of Tracker calculations for the billing periods of Jan-21 Feb-21 Mar-21

Code	Name/Description	Demand (copy from Column D)	Energy (copy from Column E)
RS	Residential Service	-	-
GP & MP	Gen. Power & Municipal Power	-	-
PP	Primary Power Service	-	-
0	0	-	-
OL	Outdoor Lighting	-	-
SL	Street Lighting	-	-
0	0	-	-
0	0	-	-
TS	Traffic Lighting	-	-
0	0	-	-
		-	-

Energy Sales (kWh) by Rate Tariff
for latest complete calendar year (from utility documents)

4/15/2021
Update Quarterly to accumulate data for Ex VI

	RS	GP & MP	PP	0	OL	SL	0	0	TS	Total Sales (kWh)	Purchased Power (kWh)	Distribution Losses (%)
Jan-20	7,668,254	3,692,322	19,941,742		102,209	113,798			10,855	31,529,178	32,548,586	3.1%
Feb-20	7,560,899	3,726,251	20,532,915		93,353	104,201			10,942	32,028,560	33,059,558	3.1%
Mar-20	6,944,541	3,567,911	20,686,376		87,274	96,533			11,029	31,393,664	32,394,951	3.1%
Apr-19	5,749,083	3,298,796	20,948,710		74,086	82,956			11,029	30,164,659	31,109,007	3.0%
May-19	5,378,033	3,337,576	21,865,921		64,751	72,702			11,029	30,730,011	31,683,379	3.0%
Jun-19	6,625,670	3,734,936	22,602,930		63,017	71,367			11,029	33,108,948	34,151,934	3.1%
Jul-19	8,620,469	4,310,750	23,149,108		71,692	81,425			10,942	36,244,385	37,412,522	3.1%
Aug-19	8,946,398	4,580,387	24,231,279		81,747	92,653			10,855	37,943,318	39,166,259	3.1%
Sep-19	7,427,579	4,153,421	23,264,932		93,936	106,429			10,855	35,057,150	36,172,559	3.1%
Oct-19	6,072,795	3,605,219	21,100,072		104,724	118,736			10,855	31,012,400	31,990,525	3.1%
Nov-19	6,271,392	3,526,467	20,122,673		113,235	127,234			10,855	30,171,855	31,130,179	3.1%
Dec-19	7,355,422	3,642,857	19,614,847		116,170	128,208			10,855	30,868,358	31,864,892	3.1%
Total	84,620,532	45,176,890	258,061,505	-	1,066,191	1,196,238	-	-	131,130	390,252,486	402,684,350	3.09%

Tracker of:	Previous Quarter For Comparison (Diff from Block A60 Above)		4/15/2021	Current Tracker	Difference
RS	-	per KWH	0.000000	-	-
GP & MP	-	per KW	0.000000	-	-
	-	per KWH	0.000000	-	-
PP	-	per KVA	-	-	-
	-	per KWH	-	-	-
0	-	per KVA		-	-
	-	per KWH		-	-
OL	-	per KWH	0.000000	-	-
SL	-	per KWH	0.000000	-	-
0	-	per KWH		-	-
0	-	per KWH		-	-
TS	-	per KWH	0.000000	-	-
0	-	per KWH			
0	-	per KWH			
Page 3 of 3 Column H Total:	-				

Energy Cost Adjustment (Revenue Report) KWH

Usage Billed by Rate Class	Jan-21	Feb-21	Mar-21	Average
RS	7,668,254	7,560,899	6,944,541	7,391,231
GP & MP	3,692,322	3,726,251	3,567,911	3,662,161
PP	19,941,742	20,532,915	20,686,376	20,387,011
OL	102,209	93,353	87,274	94,279
SL	113,798	104,201	96,533	104,844
TS	10,855	10,942	11,029	10,942
Grand Total	31,529,178	32,028,560	31,393,664	31,650,467
				4/25/2021

Demand Class Data (kW or kVA)				
GP & MP	14,197	15,133	14,197	14,509
PP	38,896	38,760	39,497	39,051
	-	-	-	-
	53,092.98	53,893.17	53,694.51	53,560.22

Attachment LAT-4 - Non-Recurring Charge Calcs - Summary of Charges

Type of Charge	Units	CEL&P Current	CEL&P Proposed	CELP Cost	Benchmarking Ave	Benchmarking Range
Service Deposit						
Rate Sched RS	Minimum $/Deposit[1]	$ 50.00	$ 60.00	$ 60.00	$ 163.33	$140.00-$200.00
Rate Sched GP, PP, and IP	Minimum $/Deposit[2]	$ 100.00	$ 120.00	$ 120.00	$ 175.00	$150.00-$200.00
Return Check Charge	$/Returned Check[3]	$ 25.00	$ 25.00	$ 23.77	$ 24.00	$15.00-$40.00
Reconnect/Disconnect Charge						
During normal Utilty hours	$/Reconnect or Disconnect	$ 40.00	$ 45.00	$ 98.17	$ 58.33	$20.00-$75.00
Outside normal Utility hours	$/Reconnect or Disconnect	$ 100.00	$ 120.00	$ 127.26	$ 91.89	$20.00-$250.00
Temporary Charge	$/Temporary Service[4]	$ 100.00	$ 150.00	$ 247.06	Est. Cost	$200.00 - Est. Cost
Meter Test Charge	$/Meter Test[5]	$ 40.00	$ 50.00	$ 214.51	$ 35.00	$15.00-$75.00
Service Call Charge						
Outside normal Utility hours	$/Service Call	$ 200.00	$ 250.00	$ 534.56	$ 57.50	$40.00-$75.00
Late Payment Charge	% of Unpaid Balance	4.0%	5.0%	4.5%	3.3%	3%-5%
Meter Base Charge						
Residential Customers	$/Meter Base	NA	$ 50.00	$ 50.00	NA	NA
Commercial Customers	$/Meter Base	NA	$ 100.00	Over $100.00	NA	NA
Electric Permit Fee	$/Permit	NA	$ 50.00	$ 908.32	NA	NA
Lot Fee	$/Lot[6]	NA	$ 1,000.00	$ 1,000.00	NA	NA

[1] Minimum for Residential Service to a maximum of 2 months anticipated usage. The actual amount shall be based on the results of a credit check.

[2] Minimum for General Power, Primary Power, and Industrial Power Service. The actual amount shall be based on the results of a credit check.

[3] For the current charge, the greater of $25.00 or 5% (but not more than $250) of the amount of the check. For the proposed charge, the greater of $25.00 or 6% (but not more than $250) of the amount of the check.

[4] When no more than a single span service drop and meter are required.

[5] If customer requests a meter test less frequently than in a 36-month period and upon test, the meter accuracy is less than 3% error.

[6] Based on 8 years to recover investment.

Attachment LAT-4 - Non-Recurring Charge Calculations - Inputs

Line No.	Description (1)	Unit (2)	Amount (3)	Source (4)
1	**Hourly Wages**			
2	Office Staff	$/hr	$ 19.68	CELP
3	Inspector	$/hr	$ 36.92	CELP
4	Lineman	$/hr	$ 39.14	CELP
5	Meter Tech	$/hr	$ 21.55	CELP
6	**Overhead Rate**	$/hr	$ 36.62	CELP
7	**Fullen Burdened Hourly Costs**			
8	Office Staff	$/hr	$ 56.30	
9	Inspector	$/hr	$ 73.54	
10	Lineman	$/hr	$ 75.76	
11	Meter Tech	$/hr	$ 58.17	
12	**Truck Charge**	$/hr	$ 40.00	CELP

Attachment LAT-4 - Non-Recurring Charge Calcs - Service Deposit

Line No.	Class (1)	Average Monthly Bill Current (2)	Step 1 (3)	Step 2 (4)	Number of Customer-Months (5)	Source (6)
1	Residential	$ 88.74	$ 94.92	$ 101.53	81,571	Att JAM-4
2	Residential Electric	$ 100.60	$ 107.79	$ 115.47	18,576	Att JAM-4
3	1 Phase General Power	$ 137.66	$ 141.04	$ 144.58	13,502	Att JAM-4
4	3 Phase General Power	$ 661.79	$ 703.82	$ 748.05	4,156	Att JAM-4
5	Primary Power	$ 21,869.11	$ 24,125.33	$ 26,599.58	918	Att JAM-4
6	Res/Res Elec Combined	$ 90.94	$ 97.31	$ 104.12	100,147	
7	% Change		7.0%	7.0%		
8	Gen Power/Prim Power Combined	$ 1,328.92	$ 1,452.29	$ 1,587.04	18,576	
9	% Change		9.3%	9.3%		

Line No.	Class (1)	Service Deposit Current (2)	Step 2 (4)	Source (5)
10	Res/Res Elec Combined	$ 50.00	$ 60.00	CELP
11	Gen Power/Prim Power Combined	$ 100.00	$ 120.00	CELP

Attachment LAT-4 - Non-Recurring Charge Calcs - Return Check Charge

Line No.	Description (1)	Unit (2)	Amount (3)	Source (4)	Current Charge (5)
1	Bank Charge	$/check	$ 5.00	CELP	
2	Office Staff Hours	hrs	0.33	CELP	
3	Burdened Labor Cost	$/check	$ 18.77		
4	Total Cost Incl Bank Charge	$/check	$ 23.77		
5	Recommended	$/check	$ 25.00	CELP	$ 25.00

Attachment LAT-4 - Non-Recurring Charge Calcs - Reconnect/Disconnect Charge

Line No.	Description (1)	Unit (2)	Amount (3)		Source (4)	Current Charge (5)	
1	Meter Tech Hours	hrs		1.00	CELP		
2	Burdened Labor Cost	$/reconnect_disconnect	$	58.17			
2	Truck Hours	hrs		1.00	CELP		
3	Truck Cost	$/reconnect_disconnect	$	40.00			
4	Total Cost	$/reconnect_disconnect	$	98.17			
3	Recommended - Normal Busine	$/reconnect_disconnect	$	45.00	CELP	$	40.00
4	After Hours Penalty	% of labor costs		50%	CELP		
5	Total Cost Incl After Hours Pena	$/reconnect_disconnect	$	127.26			
6	Recommended - After Normal B	$/reconnect_disconnect	$	120.00	CELP	$	100.00

Attachment LAT-4 - Non-Recurring Charge Calcs - Temporary Service Charge

Line No.	Description (1)	Unit (2)	Amount (3)	Source (4)	Current Charge (5)
1	Office Staff Hours to Process	hrs	0.33	CELP	
2	Office Staff Burdened Labor Cost	$/temporary service	$ 18.77		
3	Inspector Hours to Install Meter	hrs	0.50	CELP	
4	Inspector Burdened Labor Cost	$/temporary service	$ 36.77		
5	Lineman Hours to Connect/Reconnect (2	hrs	2.00	CELP	
6	Lineman Burdened Labor Cost	$/temporary service	$ 151.52		
7	Truck Hours	hrs	1.00	CELP	
8	Truck Cost	$/temporary service	$ 40.00		
9	Total Cost	$/temporary service	$ 247.06		
10	Recommended	$/temporary service	$ 150.00	CELP	$ 100.00

Attachment LAT-4 - Non-Recurring Charge Calcs - Meter Test Charge

Line No.	Description (1)	Unit (2)	Amount (3)	Source (4)	Current Charge (5)
1	Meter Tech Hours	hrs	3.00	CELP	
2	Meter Tech Burdened Labor Cost	$/meter test	$ 174.51		
3	Truck Hours	hrs	1.00	CELP	
4	Truck Cost	$/meter test	$ 40.00		
5	Total Cost	$/meter test	$ 214.51		
6	Recommended	$/meter test	$ 50.00	CELP	$ 40.00

Attachment LAT-4 - Non-Recurring Charge Calcs - Service Call Charge

Line No.	Description (1)	Unit (2)	Amount (3)	Source (4)	Current Charge (5)
1	Lineman Hours (2 linemen)	hrs	4.00	CELP	
2	Meter Tech Burdened Labor Cost	$/service call	$ 303.04		
3	After Hours Penalty	% of labor costs	50%	CELP	
4	Truck Hours	hrs	2.00	CELP	
5	Truck Cost	$/service call	$ 80.00		
6	Total Cost	$/service call	$ 534.56		
7	Recommended - After Normal Business Hrs	$/service call	$ 250.00	CELP	$ 200.00

Attachment LAT-4 - Non-Recurring Charge Calcs - Late Payment Charge

Line No.	Description (1)	Unit (2)	Amount (3)	Source (4)	Current Charge (5)
1	Office Staff Hours (6 office stafff)	hrs per month	20.00	CELP	
2	Office Staff Burdened Labor Cost	$/month	$ 1,126.00		
3	No. of Late Notices & Non-Payments	per month	230	CELP	
4	Breakdown of Late Notices and Non-Payments				
5	Residential	%	90%	Att JAM-2	
6	General Power	%	10%	Att JAM-2	
7	Average Monthly Bills (Step 2)				
8	Residential	$/month	$ 104.12	Att JAM-4	
9	General Power (1-Phase)	$/month	$ 144.58	Att JAM-4	
10	Weighted Avarge	$/month	$ 108.16		
11	Average Monthly Unpaid Balance	$/month	$ 24,877.63		
12	Labor Cost as % of unpaid balance	% of unpaid balance	5%		
13	Recommended	% of unpaid balance	5%	CELP	4%

Attachment LAT-4 - Non-Recurring Charge Calcs - Meter Base Charge

Line No.	Description (1)	Unit (2)	Amount (3)	Source (4)	Current Charge (5)
1	Average Meter Base Costs				
2	Residential	$/meter base	$ 50.00	CELP	
3	Commercial & Industrial	$/meter base	Over $100.00	CELP	
4	Recommended				
5	Residential	$/meter base	$ 50.00		NA
6	Commercial & Industrial	$/meter base	$ 100.00		NA

Attachment LAT-4 - Non-Recurring Charge Calcs - Electric Permit Fee

Line No.	Description (1)	Unit (2)	Amount (3)	Source (4)	Current Charge (5)
1	Inspector Hours (4 inspections)	hrs	8.00	CELP	
2	Inspector Burdened Labor Cost	$/permit fee	$ 588.32		
3	Truck Hours	hrs	8.00	CELP	
4	Truck Cost	$/permit fee	$ 320.00		
5	Total Cost	$/permit fee	$ 908.32		
6	Recommended	$/permit fee	$ 50.00	CELP	NA

Attachment LAT-4 - Non-Recurring Charge Calcs - Lot Fee

Line No.	Description (1)	Unit (2)	Amount (3)	Source (4)	Current Charge (5)
1	Diamond Ridge Subdivision Costs (2018-2019)				
2	Total Labor & Materials Costs	$	$ 120,737.74	CELP	
3	Number of Home Lots	# of home lots	73.00	CELP	
4	Cost Per Home Lot	$/home lot	$ 1,653.94		
5	Average Residential Mo. Bill (Step 2)	$/customer/month	$ 101.53	Att JAM-4	
6	Average Monthly Expenses	$/customer/month	$ 94.36	Att JAM-2	
7	Return on Investment	$/customer/month	$ 7.17		
8	Recommended Lot Fee	$/Lot	$ 1,000.00	CELP	NA
9	Years to Recover Investment				
10	Without Lot Fee	years	19		
11	With Lot Fee	years	8		
12	APPA Recommendation-Residential	years	5-9		

Attachment LAT-4 - Non-Recurring Charges - Benchmarking

	CEL&P Proposed	Richmond	Tipmont	Duke	Parke County	Tipton	Frankfort	Anderson	Lebanon	Peru	IPL	Ave	Range
Service Deposit													
Rate Sched RS	$ 60.00	NA	$ 200.00	1/6 th of annual billing	$ 150.00	1/4 th of annual billing	1/6 th of annual billing	1/6 th of annual billing	1/6 th of annual billing	$ 140.00	1/6 th of annual billing	$ 163.33	$140.00-$200.00
Rate Sched GP, PP, and IP	$ 120.00	NA	$ 200.00		$ 150.00					2-months est, bill		$ 175.00	$150.00-$200.00
Return Check Charge	$ 25.00	$ 20.00	$ 20.00	$ 20.00	$ 30.00	$ 25.00	$ 25.00	$ 40.00	$ 15.00	$ 25.00	$ 20.00	$ 24.00	$15.00-$40.00
Reconnect/Disconnect Charge													
During normal Utilty hours	$ 45.00	$ 30.00	$ 75.00	$ 37.00	$ 75.00	$ 20.00	$ 33.00	$ 30.00	$ 20.00	$ 25.00	$ 44.00	$ 58.33	$20.00-$75.00
Outside normal Utility hours	$ 120.00	$ 70.00	$ 75.00	$ 250.00	$ 130.00	$ 20.00	$ 93.00	$ 75.00	NA	$ 50.00	$ 64.00	$ 91.89	$20.00-$250.00
Temporary Charge	$ 150.00	NA	$ 200.00	Est.Cost	NA	NA	Est.Cost	Est.Cost	Est.Cost	NA	NA	Est. Cost	$200.00 - Est. Cost
Meter Test Charge	$ 50.00	$ 35.00	NA	NA	$ 75.00	$ 40.00	NA	$15.00-$30.00	NA	$ 15.00	NA	$ 35.00	$15.00-$75.00
Service Call Charge													
Outside normal Utility hours	$ 250.00	$ 40.00	$ 75.00	NA	NA	NA	NA	NA	NA	NA	NA	$ 57.50	$40.00-$75.00
Late Payment Charge	5%	NA	5%	3%	10% of first $3.00, then 3%	NA	3%	10% of first $3.00, then 3%	NA	3%	NA	3.3%	3%-5%
Meter Base Charge													
Residential Customers	$ 50.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Commercial Customers	$ 100.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Electric Permit Fee	$ 50.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lot Fee	$ 1,000.00	NA	NA	Cost less 2.5 yrs revenue	NA	NA	NA	NA	NA	NA	NA	NA	NA

Attachment LAT-5 - LED Lighting Design

Line No.	HPS Streetlights / Equivalent LED Streetlights	$/Fixture 100 W HPS / 47 W LED	250 W HPS / 81 W LED	400 W HPS / 142 W LED
1	HPS COS SL Operating Costs	$ 11.66	$ 13.09	$ 15.24
2	Equiv LED SL Operating Costs	$ 9.19	$ 9.85	$ 10.93
3	Difference (LED SL Costs Minus HPS SL Costs)	$ (2.47)	$ (3.24)	$ (4.31)
4	Proposed Phase 2 HPS SL Fixture Charges	$ 6.80	$ 27.55	$ 45.03
5	Less Difference in LED SL vs HPS SL Operating Costs	$ (2.47)	$ (3.24)	$ (4.31)
6	Proposed LED SL Fixture Charges	$ 4.33	$ 24.31	$ 40.72

Line No.	HPS Outdoor Lighting / Equivalent LED Outdoor Lighting	$/Fixture 100 W HPS / 47 W LED	250 W HPS / 81 W LED	400 W HPS / 142 W LED
7	HPS COS OL Operating Costs	$ 4.29	$ 5.71	$ 7.84
8	Equiv LED OL Operating Costs	$ 3.27	$ 3.93	$ 5.00
9	Difference (LED OL Costs Minus HPS OL Costs)	$ (1.01)	$ (1.78)	$ (2.84)
10	Proposed Phase 2 HPS OL Fixture Charges	$4.97	$12.81	$34.85
11	Less Difference in LED OL vs HPS OL Operating Costs	$ (1.01)	$ (1.78)	$ (2.84)
12	Proposed LED OL Fixture Charges	$ 3.96	$ 11.03	$ 32.01

Attachment LAT-5 - Lighting COS

Line No.		COS Unit Charge	High Pressure Sodium			Equivalent LED		
	Watts		100	250	400	47	81	142
	With Losses Watts		121	303	485	57	101	176
	kWh/Month		40	59	102	19	34	59
	Streetlights COS		$/Fixture			$/Fixture		
1	Demand	$ 0.0049	$ 0.60	$ 1.50	$ 2.40	$ 0.28	$ 0.50	$ 0.87
2	Energy	$ 0.0291	$ 1.17	$ 1.71	$ 2.96	$ 0.55	$ 0.98	$ 1.70
3	Customer	$ 3.80	$ 3.80	$ 3.80	$ 3.80	$ 3.80	$ 3.80	$ 3.80
4	Lighting O&M	$ 6.09	$ 6.09	$ 6.09	$ 6.09	$ 4.56	$ 4.56	$ 4.56
5	COS - Operating Expenses		$ 11.66	$ 13.09	$ 15.24	$ 9.19	$ 9.85	$ 10.93
	Outdoor Lights COS		$/Fixture			$/Fixture		
6	Demand	$ 0.0049	$ 0.59	$ 1.48	$ 2.37	$ 0.28	$ 0.49	$ 0.86
7	Energy	$ 0.0290	$ 1.17	$ 1.70	$ 2.94	$ 0.55	$ 0.98	$ 1.69
8	Customer	$ 2.23	$ 2.23	$ 2.23	$ 2.23	$ 2.23	$ 2.23	$ 2.23
9	Lighting O&M	$ 0.29	$ 0.29	$ 0.29	$ 0.29	$ 0.22	$ 0.22	$ 0.22
10	COS - Operating Expenses		$ 4.29	$ 5.71	$ 7.84	$ 3.27	$ 3.93	$ 5.00