STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF THE CITY OF RICHMOND, INDIANA, BY AND THROUGH ITS MUNICIPAL ELECTRIC UTILITY, RICHMOND POWER AND LIGHT, 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. 45361**

PRE-FILED VERIFIED DIRECT TESTIMONY OF

JOSEPH A. MANCINELLI

AND ATTACHMENT JAM-1

ON BEHALF OF PETITIONER

RICHMOND POWER & LIGHT

PETITIONER'S EXHIBIT 3

MARCH 25, 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 Joseph A. Mancinelli. I am the President and Chief Executive Officer ("CEO") of NewGen Strategies and Solutions, LLC ("NewGen"). My business address is 225 Union Boulevard, Suite 305, Lakewood, Colorado, 80228. NewGen is a consulting firm that specializes in utility rates, engineering economics, financial accounting, asset valuation, appraisals, and business strategy for electric, natural gas, water, and wastewater utilities. I am testifying on behalf of the Petitioner, Richmond Power & Light ("RP&L" or the "Utility"), which is the electric utility owned and operated by the City of Richmond, Indiana ("Richmond").

Q2. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I have more than 30 years of experience in the areas of cost of service ("COS") and rate design for electric, natural gas, water, and wastewater utilities. I have worked closely with public utility commissions, senior management teams, utility boards, city councils, attorneys, and end-users with respect to the strategy and technical fundamentals of COS and rate design. I have taught numerous classes on COS and rate design methodology based on industry methodologies approved by the National Association of Regulatory Utility Commissioners ("NARUC") and the American Public Power Association ("APPA"). I have been extensively involved in the development of unbundled COS and pricing models during my career. A summary of my qualifications is provided within Attachment JAM-1 to this testimony.

Q3. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, as shown in Attachment JAM-1, I have testified before the Indiana Utility Regulatory Commission ("IURC") four times.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain RP&L's recommended rate design and supporting cost of service study. With respect to rate design, I will describe RP&L's rate design objectives and proposed overall rate structure. My colleague Laurie Tomczyk will provide direct testimony regarding RP&L's revenue requirement and the need to modify RP&L's Energy Cost Adjustment procedures. My colleague Andrew Reger will provide direct testimony specific to rate design applicable to Lighting Service, Electric Heating Service - School, General Electric Heating Service, and a new Electric Vehicle rate. Also, Mr. Reger will provide direct testimony in support of proposed changes to miscellaneous non-recurring fees and charges in RP&L's proposed Schedule B.

Q5. WHICH OF THE MINIMUM STANDARD FILING REQUIREMENTS IN EXHIBIT 5 ARE YOU SPONSORING IN THIS CAUSE?

A. I am sponsoring the following, which correspond to the respective Commission Minimum Standard Filing Requirement ("MSFR") found in 170 IAC 1-5 as indicated below:

- Exhibit 5 (170 IAC 1-5-8(a)(4)) – Pro Forma Revenues, Sales and Number of Customers for the Test Year
- Exhibit 5 (170 IAC 1-5-15(h)) – Cost of Service Study
- Exhibit 5 (170 IAC 1-5-16(b)) – New RP&L Tariff, Clean Version
- Exhibit 5 (170 IAC 1-5-16(c)) – New RP&L Tariff, Redlined Version
- Exhibit 5 (170 IAC 1-5-16(d)) – Residential Bill Comparison

Q6. WHAT ATTACHMENTS ARE YOU SPONSORING IN THIS CAUSE?

A. My direct testimony includes the following Attachments:

- Attachment JAM-1 - Resume of Joseph A. Mancinelli
- Attachment JAM-2 - Cost of Service Study Model
- Attachment JAM-3 – Rate Design Model
- Attachment JAM-4 - Clean Version of the Proposed New RP&L Tariff
- Attachment JAM-5 - Redlined Version of the Proposed New RP&L Tariff
- Attachment JAM-6 – Residential Rate Design
- Attachment JAM-7 – Rate Comparisons

Q7. WERE THESE EXHIBITS AND ATTACHMENTS PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

II. OVERVIEW OF TESTIMONY

Q8. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY AND RECOMMENDATONS.

A. My testimony describes the development of RP&L's cost-of-service study, which allocates RP&L's Test Year Revenue Requirement ("Revenue Requirement") to each rate class. The cost of service study functionalizes, sub-functionalizes, classifies, and allocates costs using generally accepted methodologies recognized by NARUC and APPA. The cost allocation methodology yields a fair and equitable result based on principles of cost causation. Also, I will discuss in detail the RP&L's rate design objectives, class revenue targets, proposal to implement requested rate in three phases over a three-year period, and RP&L's proposed new tariff. Important considerations of the proposed rate structure include improved energy efficiency pricing signals to residential customers, the introduction of demand charges to all

General Power Service and General Electric Heating customers, and the creation of new commercial and industrial rate classes for future use.

Q9. WHAT IS THE TEST PERIOD USED TO PREPARE THE CLASS COST-OF-SERVICE STUDY IN THIS PROCEEDING?

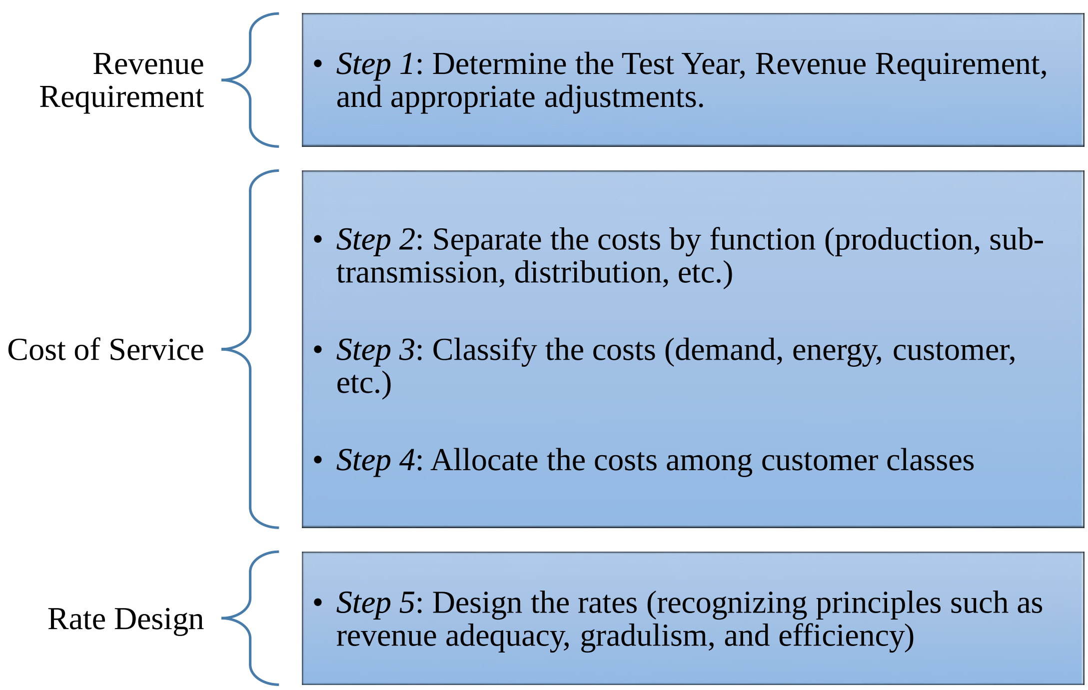
A. The test period used to develop the class cost-of-service study is an historic test year including the twelve-month period ending September 30, 2019 ("Test Year"), with fixed, known and measurable adjustments through September 30, 2020.

III. <u>RATEMAKING APPROACH</u>

Q10. WHAT ARE THE BASIC STEPS IN THE RATEMAKING PROCESS?

A. The basic steps of the ratemaking process are described in the following Figure JAM-1.

Figure JAM-1



Q11. BRIEFLY DESCRIBE THE PURPOSE OF A COST OF SERVICE STUDY ("COSS").

A. A COSS determines cost responsibility of the various customer classes served by the Utility. Cost responsibility is primarily a function of customer service requirements and usage characteristics. For example, customer service requirements are often related to customer delivery requirements, while customer usage characteristics are related to the demand and energy needs of the customer.

Q12. WHAT ARE THE DIFFERENT TYPES OF COSTS IDENTIFED BY A COSS?

A. A COSS identifies the underlying nature of costs (or cost classification) which are typically Demand-related, Energy-related, and Customer-related. Demand-related costs are costs that are fixed in nature and do not vary with day-to-day changes in system energy use. Demand-related costs are typically associated with system capacity requirements. To ensure high reliability, utilities like RP&L must have sufficient infrastructure and/or contracts to meet the system peak whenever that occurs. Demand-related costs are directly attributable to customer and class contribution to localized distribution and centralized system peak demands. Energy-related costs are variable in nature and vary with day-to-day changes in system energy use. Customer-related costs such as billing, collections and customer service functions, are driven by the number of customers on the system.

Q13. HOW IS CUSTOMER CLASS COST RESPONSIBILITY DETERMINED IN A COSS?

A. Class cost responsibility is based on class contribution to system demand, energy and customer requirements. In other words, a utility like RP&L incurs costs to meet customer requirements for electricity service. A COSS maps utility costs to customer classes by examining the underlying drivers of cost required to meet customer electricity needs. The underlying drivers of certain utility costs are well-known and measured. The application of these drivers are used to allocate costs to each customer class in a widely accepted non-controversial manner. For example, the underlying driver of purchased power costs billed on an energy basis is system energy requirements. Therefore, purchased power costs can be allocated to each customer class based on class energy sales adjusted for system losses. Since utilities measure energy usage for most classes, this allocation method is supported by complete information and renders a non-controversial result. However, the underlying drivers of other system costs, particularly Demand-related costs, are less well known. Demand-related costs are allocated to the various customer classes based on a measure of class contribution to peak demand at different locations on the system. Since many utilities, including RP&L, do not routinely measure peak demand contributions by all customers on the system, the use of ancillary analyses and/or judgment and experience to develop class demand responsibility is required.

Given these cost causation principles and available information, I have prepared a comprehensive cost of service study for RP&L current customer classes. COSS results determine the cost responsibility of each class. Further, for each class, the COSS indicates levels of customer charges, energy charges, and demand charges.

Q14. PLEASE DESCRIBE HOW YOU PREPARED THE COSS.

A. The COSS was prepared using embedded or average system costs as detailed in the Revenue Requirement for the Test Year, as calculated by witness Laurie A. Tomczyk. The Revenue Requirement was input into NewGen’s unbundled cost of service model customized for the RP&L system (see Attachment JAM-2). The model is organized consistent with an industry standard three step process of functionalization, classification, and allocation of the revenue requirement to various customer classes.

Q15. WHAT IS THE SOURCE OF THE DATA USED IN THE COSS?

A. The data used in the COSS includes:

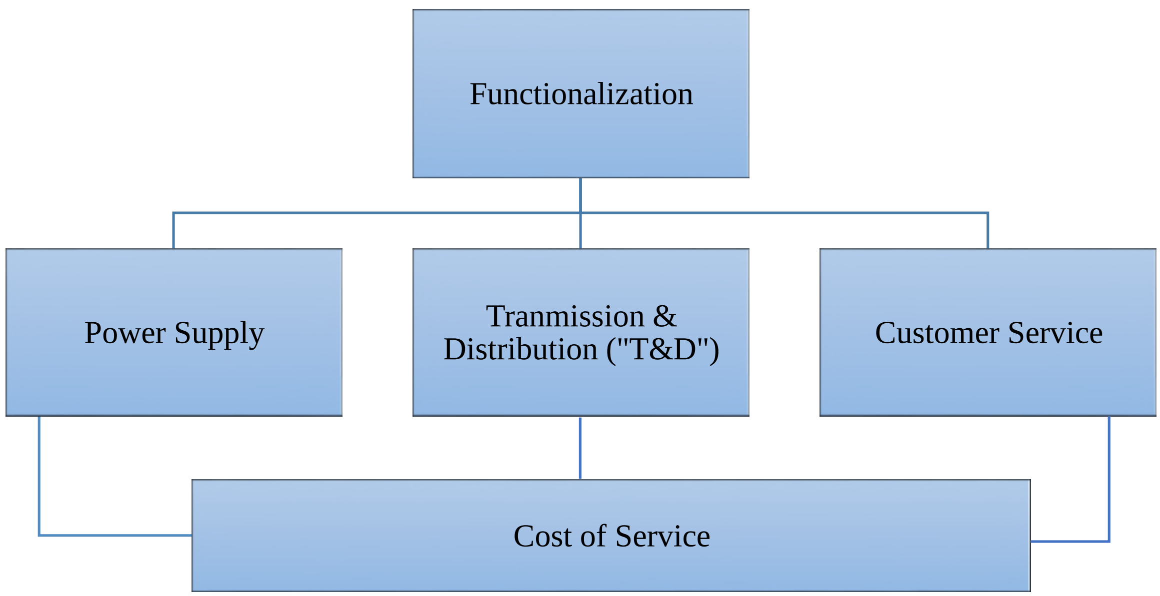
1. Financial data as detailed in the revenue requirement was provided by RP&L and adjusted as necessary by witness Laurie A. Tomczyk. Additional financial data pertaining to labor cost by Federal Energy Regulatory Commission ("FERC") account and utility plant in service was provided by RP&L staff;
2. Monthly system operating data and statistics pertaining to system peak demand and energy purchases was provided by RP&L staff;
3. System sub-transmission and distribution infrastructure statistics and related cost was provided by RP&L staff;
4. Monthly billing data and associated revenue by class was provided by RP&L staff; and
5. Class peak demand data used in the development of demand allocation factors relied upon available Advanced Metering Infrastructure ("AMI") 30-minute interval load data for the Residential Electric Service customer class and hourly Automated Meter Reading ("AMR") interval load data for the Large Power Service and Industrial Service customer classes. Indianapolis Power and Light ("IP&L") load research data was used for the Commercial Lighting Service, General Electric Heating, and Electric Heating School. Coincident demand data for the General Power class was assumed based on Commercial Lighting and Large Power class data and assumptions.

IV. COST OF SERVICE - FUNCTIONALIZATION OF COSTS

Q16. PLEASE DESCRIBE THE COMPONENTS OF THE FUNCTIONALIZATION STEP.

A. Functionalization (or Functional Unbundling) is the first step in the cost of service process. In this step, costs are assigned to the major RP&L business functions of Power Supply, Sub-Transmission and Distribution, and Customer Service. Assignments are made for the detailed Revenue Requirement, as well as labor costs by FERC account and plant in service. The key components of the Functionalization step include the following modules:

Figure JAM-2



- Power Supply Module – The Power Supply function as determined in the Functional Unbundling module is further sub-functionalized into Indiana Municipal Power Authority ("IMPA") purchased power costs and costs associated with RP&L's

Whitewater Valley Station ("WWVS") power plant.[1] Sub-functionalized costs were classified as either Demand-related or Energy-related depending upon the underlying nature of the costs. The Revenue Requirement, labor costs, and plant in service assigned to this function were sub-functionalized and classified within this module.

- Sub-Transmission and Distribution ("T&D)" Module – The Sub-Transmission and Distribution function as determined in the Functional Unbundling module is further sub-functionalized into various components of the combined sub-transmission and distribution systems. RP&L receives purchased power at three interconnection points, two at 138 kilovolts ("kV") and one at 69kV. Once received, RP&L delivers this power across its service territory via 28 miles of sub-transmission line tied to the distribution system with twelve 69/13.8kV substations. The distribution system includes approximately 415 miles of primary line, 360 miles of secondary line and an additional fourteen substations. Sub-transmission voltage is stepped down to distribution primary voltages of 2.4kV, 12.47kV and 13.8 kV, and then further stepped down to distribution secondary voltages of less than 2.4kV. RP&L does not separately account for sub-transmission and distribution operation and maintenance expenses, so for cost allocation purposes, we have combined these assets into a single "wires" function. Sub-Transmission and Distribution costs are sub-functionalized as follows:

  - Sub-trans.
  - Substations
  - Primary
  - Secondary
  - Transformers
  - Service Drops
  - Meters
  - Outdoor Lighting
  - Street Lighting

[1] As indicated in the direct testimony of Randall W. Baker, RP&L is a full-requirements customer of IMPA, and IMPA has taken over operational control of WWVS.

- Load Dispatch

Depending upon the underlying nature of each sub-functional category, costs were classified as either Demand-related or Customer-related. The Revenue Requirement, labor costs, and plant in service assigned to this function were sub-functionalized and classified within this module.

- Customer Service Module – The Customer function as determined in the Functional Unbundling module is further sub-functionalized into various customer service activities as follows:
  - Meter Reading
  - Sales
  - Accounting
  - Uncollectibles
  - Customer Service

  All of these sub-functions were classified as Customer-related. The Revenue Requirement, labor costs and plant in service assigned to this function were sub-functionalized and classified within this module.

- Cost of Service Module – The COS module summarizes the sub-functionalized and classified components of each unbundling category. This detail is allocated to each customer class based on various allocations factors which agree with the category classification. The allocated components are summed for each customer class yielding cost of service results by class. Cost of service by class is then compared to Test Year rate revenues by class to determine the adequacy of current rates.

Q17. PLEASE DESCRIBE THE FUNCTIONALIZATION PROCESS.

A. As previously described, the Revenue Requirement was assigned to Power Supply, T&D, and Customer Service functions based on direct and derived allocation factors. Direct allocation factors assign costs to functions based on the underlying FERC account. For example, costs in FERC account 555 – Purchased Power were directly assigned to the Power Supply function. Derived allocation factors were used to allocate joint or common costs to the various functions. For example, costs in FERC account 920 - Administration and General Expense – Salaries-General Manager and Staff were allocated to each function based on derived allocator using labor cost directly assigned to each function.

Q18. WHAT ARE THE RESULTS OF THE FUNCTIONAL UNBUNDLING ANALYSIS?

A. The results of the functional unbundling analyses are shown in Table JAM-1.

Table JAM-1
Functional Unbundling Results (1)

Line No.	Functions	Test Year Rev. Req. ($)	% of Total
1	Power Supply	$69,223,688	78%
2	Sub-Transmission and Distribution	17,163,509	19%
3	Customer	2,066,007	2%
4=1+2+3	Total	$88,453,204	100%

(1) See Attachment JAM-2, pp. 69-108 (Functional Unbundling).

Using the ECA tracker, RP&L passes onto its customers incremental IMPA power supply costs above (or below) those costs collected in the base rates. In this study, it is RP&L's intention to collect the entire Revenue Requirement related to power supply in base rates, which includes IMPA power supply costs. This approach will effectively reset the ECA tracker to zero. As a result, the cost of service study functionalizes, classifies and allocates power supply costs to all customer classes. The single largest cost on the RP&L system is related to IMPA power supply costs, which represent 91.6% ($63,409,146[2] / $69,223,688) of power supply costs and 71.7% of the Revenue Requirement ($63,409,146 / $88,453,204). The power supply function includes costs associated with IMPA and the WWVS. Although IMPA operates WWVS and passes on operating costs to IMPA members, RP&L owns WWVS and incurs direct and indirect costs of which the primary component is depreciation.

IV. <u>COST OF SERVICE - CLASSIFICATION OF COSTS</u>

Q19. PLEASE DESCRIBE THE COST CLASSIFICATION PROCESS.

A. Costs were classified into demand, energy, customer, and direct assignment components based on the underlying nature of the costs as previously described in my testimony. Power Supply function costs were classified as either Demand-related or Energy-related. T&D function costs were classified as either Demand- or Customer-related or were directly assigned. Customer function costs were classified as Customer-related, while some costs are directly assigned to a certain customer or class of customers.

Q20. WHAT ARE THE RESULTS OF THE CLASSIFICATION OF CUSTOMER FUNCTION COSTS?

A. Attachment JAM-2, pp. 106 presents the Revenue Requirement on a functionalized and classified basis. Summing the various Demand-related, Energy-related, Customer-related and Direct Assignment components yields the following results shown in Table JAM-2.

[2] See Attachment JAM-2, pp. 69-83.

Table JAM-2
System Classified Costs (1)

Line No.	Classifications	Test Year RR ($)	% of Total
1	Demand - Related	$56,137,144	63%
2	Energy - Related	25,654,583	29%
3	Customer - Related	5,933,009	7%
4	Direct Assignment	728,468	1%
5=Sum 1–4	Total	$88,453,204	100%

(1) See Attachment JAM-2, pp. 106.

Note that direct assignments were made to RP&L's lighting classes. Considering that demand, customer, and directly assigned costs are fixed in nature, approximately 70% of RP&L's system costs are fixed and do not vary with energy usage.

Q21. PLEASE DESCRIBE THE CUSTOMER CLASSES IN WHICH COSTS WERE ALLOCATED.

A. The COSS allocates costs to eleven current RP&L customer classes. A description of each of these classes is shown in Table JAM-3 below.

Table JAM-3
Customer Class Criteria [1]

Line No.	Customer Class	Criteria
1	Residential Electric Service	Domestic Use Only
2	Commercial Lighting Service	Maximum monthly demand equal to or less than 11 kilowatts (“kW”) in aggregate capacity
3	General Power Service	Maximum monthly demand greater than 11 kW or customer has a three-phase power load
4	Large Power Service – Secondary [2]	Maximum monthly demand of 50 kW or more
5	Large Power Services - Coincident Peak – Secondary [3]	Maximum monthly demand of 50 kW or more, Customer must be able to move at least 5% of demand from the on-peak period to the off-peak period
	Large Power Services - Coincident Peak – Primary [3]	Maximum monthly demand of 50 kW or more, Customer must be able to move at least 5% of demand from the on-peak period to the off-peak period
6	Industrial Service – Primary [4]	Maximum monthly demand of 850 kW or more
7	Industrial Service - Coincident Peak-Primary [5]	Maximum l monthly demand of 850 kW or more, Customer must be able to move at least 5% of demand from the on-peak period to the off-peak period
8	Electric Heating Schools	Building must be part of a school complex – Class closed to new customers after 1980
9	General Electric Heating	50% of customer load must be in a building whose heating source is primarily electric space heating – class closed to new customers after 1980
10	Outdoor Lighting Services	Outdoor lighting on private property
11	Street Light Services	City lighting

(1) On a case by case basis, RP&L has allowed customers whose load characteristics have changed, the flexibility to select the rate class that best suits their needs.
(2) All customers in the Large Power Service class receive electricity at secondary voltage.
(3) Customers in the Large Power Services-Coincident Peak class were segregated into separate classes based on ownership of distribution transformers.
(4) All customers in the Industrial Service class receive electricity at primary voltage and own their own distribution transformers.
(5) All customers in the Industrial Service-Coincident Peak Primary class receive electricity at primary voltage and own their own distribution transformers.

V. COST OF SERVICE – COST ALLOCATION

Q22. WHAT HAPPENS AFTER COSTS HAVE BEEN FUNCTIONALIZED AND CLASSIFIED?

A. Once the costs have been functionalized and classified, the next step is to allocate the costs among the rate classes.

Q23. PLEASE DESCRIBE HOW YOU ALLOCATED COSTS TO THE VARIOUS CUSTOMER CLASSES.

A. Costs were allocated to the various customer classes consistent with the sub-functionalized cost classification. Specifically, class allocation factors were as follows:

(1) Power supply costs were classified as either demand-related or energy-related. Demand-related costs were allocated using the 12 coincident peak method ("12CP"). The 12CP was calculated coincident with the IMPA peak, which is the basis for IMPA billed demand charges. Similarly, demand-related costs associated with WWVS are allocated using a 12CP. Although RP&L owns this power plant, IMPA operates and dispatches the plant, so it is reasonable to allocate fixed costs associated with this facility in a similar manner as IMPA purchased power costs. Energy-related costs were allocated to each class based on the class net energy for load ("NEFL"). NEFL is calculated for each class in consideration of the class delivery voltage and associated system losses.

(2) Sub-Transmission and distribution costs were classified as either demand-related, customer-related, or directly assigned. Demand-related costs were allocated to the various customer classes based on system voltage and typical system configuration. High voltage 69 kilovolt sub-transmission and substation facilities placed throughout the RP&L service territory were allocated using 12CP. This allocation approach recognizes that system coincidence is important in the location and sizing of these facilities. As load moves through the system, from delivery points to various neighborhoods within the RP&L's service territory, class peak demands influence infrastructure investment; therefore,

primary and secondary facilities were allocated using the class non-coincident peak ("NCP"). This allocation method recognizes that localized maximum demands drive utility distribution investment. At the customer delivery point, customer maximum demand is the primary driver of infrastructure investment at the customer premises. For RP&L, costs associated with distribution transformers and service drops were allocated to each custom class based on the Sum or Maximum Demands ("SMD") or billing demand for customer classes with demand charges. Meters were classified as customer-related and allocated to each customer class based on the weighted number of customers. Lighting costs were directly assigned to the outdoor lighting services and street light services rate classes.

(3) Customer costs were classified as customer-related and allocated to the various customer classes based on weighted number of customers. Weighting factors were determined based on feedback from RP&L staff.

Q24. PLEASE DESCRIBE YOUR ALLOCATION OF THE COST OF SYSTEM LOSSES.

A. System losses were determined using available information provided by RP&L. For the Test Year a System loss factor of 5.01% was calculated when comparing IMPA wholesale power purchases to retail system energy sales. Consistent with loss differentials associated with secondary and primary service as contained in RP&L's current tariff, I assumed a 2.00% differential. Given this information, I calculated secondary and primary losses of 3.48% and 1.48% respectively to yield an overall 5.01% system loss factors. This calculation can be found in Attachment JAM-2, pp. 155-156 (Retail Loss Data). It is necessary to account for system losses so that RP&L's rates are established and are sufficient to recover RP&L's Revenue

Requirement based on the amount of energy actually sold to retail customers and not on the amount of energy purchased at wholesale.

Q25. WHAT CRITERIA DID YOU USE TO ENSURE THAT THE ALLOCATION OF COSTS TO THE CUSTOMERS WAS APPROPRIATE?

A. To ensure a reasonable and appropriate cost of service result, I relied on actual system and class usage characteristics to the greatest extent possible to develop Demand-, Energy-, and Customer-related allocation factors. The resulting customer class cost of service derived from the use of these allocation factors were then checked against results I would typically expect given RP&L's cost structure and allocation methodology. Given variations in customer usage characteristics and use of system infrastructure, it is expected that classes with low monthly load factors served at secondary voltage would have the highest cost of service. For RP&L, these customer classes are Street Light Services, Residential Electric Service, and Commercial Lighting Service. Customer classes with electricity delivered at higher voltages and with higher monthly load factors would have a lower cost to serve. These results are in fact borne out by COS results, as shown in Table JAM-4.

Table JAM-4
Cost of Service by Rate Class (1)

Line No.	Customer Class	Average COS ($/kWh)
1	Commercial Lighting Service	$0.1401
2	Street Light Services	0.1334
3	Residential Electric Service	0.1284
4	Outdoor Lighting Services	0.1250
5	General Electric Heating	0.1083
6	Electric Heating Schools	0.1042
7	General Power Service	0.1021
8	Large Power Service - Secondary	0.0968
9	Large Power Services - Coincident Peak - Secondary	0.0901
10	Industrial Service – Coincident Peak - Primary	0.0818
11	Large Power Services – Coincident Peak - Primary	0.0790
12	Industrial Service - Primary	0.0731
13=Sum 1–12	**Total**	**$0.0981**

(1) See Attachment JAM-2, pp. 106, line 42 (Cost of Service by Class).

Further confidence in the results can be ascertained given that RP&L is implementing a system-wide AMI program for residential customers which compliments its AMR metering capability for larger commercial and industrial customers. In this study, available AMI and AMR data was used to determine demand responsibilities associated with the Residential Electric Service, Large Power Service, and Industrial Service rate classes.

VI. COST OF SERVICE RESULTS

Q26. WHAT WERE THE RESULTS OF ALLOCATING COSTS TO THE INDIVIDUAL CUSTOMER CLASSES?

A. Based on the results of Test Year Revenue Requirement as compared to adjusted current rate revenue, the COSS determined that rates must be increased by 9.6% for RP&L to recover its costs of serving electric customers. Table JAM-5 below demonstrates the results of allocating the Test Year Revenue Requirement to individual customer classes.

Table JAM-5
Cost of Service Compared to Current Rates

Line No. (a)	Customer Class (b)	Current Base Rate[1] ($) (c)	Current ECA[1] ($) (d)	Current Total [2] ($) (e)	COS Total [2] ($) (f)	Change[2] ($) (g) (f) –(e)	Change[2] (%) (h) (f)/(e)-1
1	Residential Electric Service	$11,980,515	$7,158,739	$19,139,254	$24,103,924	$4,964,670	25.9%
2	Commercial Lighting Service	2,967,890	2,169,379	5,137,269	4,942,590	(194,678)	(3.8%)
3	General Power Service	7,961,233	5,058,182	13,019,416	13,538,467	519,052	4.0%
4	Large Power Service - Secondary	3,078,692	2,673,416	5,752,108	6,247,177	495,069	8.6%
5	Large Power Services – Coincident Peak - Primary	7,250,611	6,178,902	13,429,513	13,873,058	443,545	3.3%
6	Large Power Services - Coincident Peak - Secondary	5,602,022	4,750,847	10,352,869	11,490,518	1,137,649	11.0%
7	Industrial Service - Primary	4,220,731	3,507,066	7,727,796	7,975,569	247,772	3.2%
8	Industrial Service – Coincident Peak - Primary	2,446,006	2,225,034	4,671,040	4,553,382	(117,658)	(2.5%)
9	Electric Heating Schools	25,922	18,623	44,545	50,756	6,211	13.9%
10	General Electric Heating	205,005	127,873	332,878	361,492	28,614	8.6%
11	Outdoor Lighting Services	226,853	35,880	262,733	396,197	133,463	50.8%
12	Street Light Services	773,945	73,991	847,936	920,073	72,138	8.5%
13=Sum 1–12	**Total**	**$46,739,423**	**$33,977,933**	**$80,717,356**	**$88,453,204**	**$7,735,848**	**9.6%**

(1) See Attachment JAM-3, pp. 18-33 (Rate Design Model).
(2) See Attachment JAM-2, pp. 106-108 (Cost of Service).

Q27. WHAT WERE THE COST OF SERVICE RESULTS BY COST CLASSIFICATION?

A. The cost of service results by cost classification are shown in Table JAM-6.

Table JAM-6
Cost of Service by Classification(1)

Line No. (a)	Customer Class (b)	Demand - Related ($) (c)	Energy - Related ($) (d)	Customer - Related ($) (e)	Direct Assignment ($) (f)	Total ($) (g)
1	Residential Electric Service	$15,244,258	$5,409,798	$3,449,868	$0	$24,103,924
2	Commercial Lighting Service	2,828,352	1,016,994	1,097,244	0	4,942,590
3	General Power Service	8,828,497	3,823,127	886,843	0	13,538,467
4	Large Power Service - Secondary	4,203,851	1,859,904	183,422	0	6,247,177
5	Large Power Services – Coincident Peak - Primary	8,928,795	4,893,159	51,104	0	13,873,058
6	Large Power Services - Coincident Peak - Secondary	7,595,541	3,673,933	221,045	0	11,490,518
7	Industrial Service - Primary	4,929,177	3,037,029	9,363	0	7,975,569
8	Industrial Service – Coincident Peak - Primary	2,994,168	1,549,851	9,363	0	4,553,382
9	Electric Heating Schools	34,224	14,033	2,499	0	50,756
10	General Electric Heating	243,052	96,181	22,260	0	361,492
11	Outdoor Lighting Services	103,596	91,361	0	201,240	396,197
12	Street Light Services	203,631	189,215	0	527,228	920,073
13=Sum 1–12	**Total**	**$56,137,144**	**$25,654,583**	**$5,933,009**	**$728,468**	**$88,453,204**

(1) See Attachment JAM-2, pp. 106-108.

Q28. DOES RP&L'S PROPOSED RATE DESIGN FOLLOW STRICT COST OF SERVICE AS REFLECTED IN THESE TABLES?

A. No. As I will explain in the next section, RP&L instructed me to deviate from strict cost of service in order to ease the transition to new rates, mitigate rate impact and avoid customer rate shock.

VII. RATE DESIGN AND MITIGATION

Q29. PLEASE EXPLAIN RP&L'S RATE DESIGN PRINCIPLES?

A. Rate design principles represent the policies, goals, and objectives important to RP&L and the community in which they serve. Given that it has been 16 years since RP&L's last rate case, rate design mitigation principles as established by RP&L for this proceeding. These principles are as follows:

1) Ensure revenue adequacy: Design rates that in total meet RP&L's revenue targets over a three-year implementation period, such that at the end of the period, rates revenues meet the total system revenue requirement.
2) Implement gradualism in rate design by:
    A. Minimizing adverse rate impacts to customer by spreading rate increases over three years in three-phases, such that RP&L anticipates Phase I will be effective when the Final Order in this Cause is issued around January 2021, then Phase II one year later in 2022, and finally Phase III another year later in 2023;
    B. Increasing system revenues by a similar amount in each year (2.9%, 3.3%, 3.1%, respectively);
    C. Limiting annual customer class rate increases to 5%; and
    D. Allowing no customer class to receive a rate decrease.
3) Given gradualism objectives, better align rates given COSS results.

4) Improve efficiency signals sent to various commercial and industrial customer classes by:
   A. Defining customer class qualification criteria to minimize discretionary customer migration between classes; and
   B. Introducing demand charges to all commercial customers with peak demand greater than or equal to 11 kW.
5) Improving fixed cost recovery by:
   A. Introducing customer charges to customer classes currently without such charges.
   B. Introducing demand charges to all commercial customers with peak demand greater than or equal to 11 kW.
   C. Increasing customer service charges towards cost of service over the implementation period.
   D. Increasing demand charges towards cost of service over the implementation period.
6) Improve conservation signals to the residential electric service customer class by phasing out existing declining block rates.
7) Create new commercial and industrial rate classes to meet potential future customer service needs.
8) Recalibrate electric cost adjustment ("ECA") so that ECA pass-through charges are near zero. As previously discussed, RP&L has included all power supply costs in the base rates thereby resetting the ECA.

Q30. PLEASE DESCRIBE HOW CLASS REVENUE TARGETS WERE ESTABLISHED AND THE IMPACT OF PROPOSED RATE CHANGES OVER RP&L'S THREE-PHASE RATE IMPLEMENTATION PERIOD.

A. Consistent with these rate design mitigation principles, RP&L's class revenue targets were established by phase as outlined in the following steps:

<u>Step 1</u> – Given COSS results, the total system rate increase to meet the cost of service was initially apportioned in three relatively equal steps so that the total revenue from all customer classes equaled the system target revenue for each phase of the three-year phase-in.

<u>Step 2</u> – Given the apportionment as described in Step 1, and the total indicated rate change per the COSS, the annual customer class rate increases were capped at 5%.

<u>Step 3</u> – Given the annual 5% cap, any revenue shortfall required to meet the system revenue target was prorated across all customer classes based on the class target revenue. If the proration resulted in a customer class previously below the cap to now be above the cap, that customer class was capped at 5% and a second iteration of the proration was performed until all customer classes met the criteria.

<u>Step 4</u> – Rates were initially designed for each phase, with consideration to COSS results and rate design objectives. Specific charges within each rate structure were gradually adjusted in three relatively equal amounts for each phase.

<u>Step 5</u> – Initial rate design was compared across similar commercial and industrial classes to ensure that pricing signals were consistent and transitions between classes did not unduly impact customers as they move from one class to another. To accomplish this objective, rates design was adjusted. This adjustment resulted in slight modifications to annual system

and customer class revenue targets. The result of this five-step process is summarized in Table JAM-7.

Table JAM-7
Proposed Rates on Current Revenues by Class [1]

Line No.	Customer Class	Current Total ($)	Phase 1 Total ($)	Phase 1 Current Change (%)	Phase 2 Total ($)	Phase 2 Cumulative Change (%)	Phase 2 – Phase 1 Change (%)	Phase 3 Total ($)	Phase 3 Cumulative Change (%)	Phase 3 – Phase 2 Change (%)
1	Residential Electric Service	$19,139,254	$20,097,319	5.0%	$21,101,419	10.3%	5.0%	$22,156,063	15.8%	5.0%
2	Commercial Lighting Service	5,137,269	5,181,018	0.9%	5,223,390	1.7%	0.8%	5,263,299	2.5%	0.8%
3	General Power Service	13,019,416	13,312,573	2.3%	13,601,523	4.5%	2.2%	13,893,174	6.7%	2.1%
4	Large Power Service - Secondary	5,752,108	5,962,876	3.7%	6,176,163	7.4%	3.6%	6,398,459	11.2%	3.6%
5	Large Power Services – Coincident Peak - Primary	13,429,513	13,676,918	1.8%	13,924,688	3.7%	1.8%	14,168,304	5.5%	1.7%
6	Large Power Services - Coincident Peak - Secondary	10,352,869	10,870,436	5.0%	11,413,813	10.2%	5.0%	11,983,445	15.7%	5.0%
7	Industrial Service - Primary	7,727,796	7,729,605	0.0%	7,829,265	1.3%	1.3%	7,898,827	2.2%	0.9%
8	Industrial Service – Coincident Peak - Primary	4,671,040	4,712,166	0.9%	4,929,104	5.5%	4.6%	5,037,568	7.8%	2.2%
9	Electric Heating Schools	44,545	46,770	5.0%	49,116	10.3%	5.0%	51,568	15.8%	5.0%
10	General Electric Heating	332,878	344,976	3.6%	357,542	7.4%	3.6%	370,059	11.2%	3.5%
11	Outdoor Lighting Services	262,733	275,857	5.0%	289,662	10.2%	5.0%	304,155	15.8%	5.0%
12	Street Light Services	847,936	877,054	3.4%	905,490	6.8%	3.2%	934,852	10.3%	3.2%
13=Sum 1–12	**Total**	**$80,717,356**	**$83,087,569**	**2.9%**	**$85,801,175**	**6.3%**	**3.3%**	**$88,459,774**	**9.6%**	**3.1%**

1) See Attachment JAM-3, p. 17.

As the table indicates, Residential Electric Service, Large Power Services – Coincident Peak - Secondary, Electric Heating Schools, and Outdoor Lighting Services receive a 5% increase in each year over the three-year rate implementation period. Given these criteria, the Residential Electric Service, Large Power Services – Coincident Peak -- Secondary, Electric Heating – Schools, and Outdoor Lighting Services were capped at annual rate increases of 5%.

Q31. WHAT IS THE CUMULATIVE IMPACT OF THE THREE-YEAR PHASED IN RATE PLAN COMPARED TO THE ALLOCATED CLASS-LEVEL COST OF SERVICE?

A. The cumulative impact of RP&L's three-year phase-in plan in system revenues results in RP&L foregoing approximately $8 million of the Revenue Requirement to which it would otherwise be entitled, as shown in Table JAM-8.

Table JAM-8[1]
Foregone Revenue Associated with Three-Year Phase-In

Line No.	Phase	Target Rate Revenue	TY Revenue Requirement	Difference
1	1	$83,087,569	$88,453,204	($5,365,635)
2	2	$85,801,175	$88,453,204	($2,652,029)
3	3	$88,459,774	$88,453,204	$6,570
4=1+2+3	**Total**	**n/a**	**n/a**	**($8,011,093)**

(1) Attachment JAM-3, p.17.

RP&L is committed to foregoing this $8 million by carefully managing its budget, expenditures and capital improvement projects in order to provide this benefit to residential customers and absorb the difference between its Test Year Revenue Requirement and the Target Rate Revenue that it will receive in Phases 1 and 2.

Q32. WHAT IS THE IMPACT OF THE FOREGONE REVENUE DURING PHASES 1 AND 2 ON RP&L'S EFFECTIVE RATE OF RETURN?

A. RP&L will not achieve revenues equal to its full cost of service until Phase 3 of the phase-in period. As described in the testimony of Ms. Laurie Tomczyk, although RP&L's requested Revenue Requirement includes a 6.59% Return on Rate Base (ROR), the effective cumulative average return over the three-year phase in period is only 2.6%. In fact, because of the delay, the effective cumulative average ROR over the next 10 years will never achieve the target 6.59% ROR under the rate and cost assumptions assumed by Ms. Laurie Tomczyk in her base case analysis.

Q33. HOW DID THE MITIGATION PRINCIPLES IMPACT THE RATE DESIGN AT THE CLASS LEVEL?

A. The most significant impacts of RP&L's rate design principles are associated with changes to the rate structure for the Residential Electric Service and General Power Service customer classes. RP&L recognized that, in particular, residential customers could not bear a full cost of service increase of 25.9%. For all other classes, implementation of rate design principles had a lesser impact on customers within each class as rate structures remain similar to the current rates. Upon the completion of the Phase 3 rate adjustment, rate revenue compared to the allocated class-level cost of service is shown in Table JAM-9.

Table JAM-9
Three-Year Rate Plan Impact by Class (1)

Line No.	Customer Class	Current Revenue ($)	COS Revenue ($)	COS/Current Revenue -1	Phase 3 Revenue ($)	Phase 3/ COS Revenue -1
1	Residential Electric Service	$19,139,254	$24,103,924	25.9%	$22,156,063	(8.1%)
2	Commercial Lighting Service	5,137,269	4,942,590	(3.8%)	5,263,299	6.5%
3	General Power Service	13,019,416	13,538,467	4.0%	13,893,174	2.6%
4	Large Power Service - Secondary	5,752,108	6,247,177	8.6%	6,398,459	2.4%
5	Large Power Services – Coincident Peak - Primary	13,429,513	13,873,058	3.3%	14,168,304	2.1%
6	Large Power Services - Coincident Peak - Secondary	10,352,869	11,490,518	11.0%	11,983,445	4.3%
7	Industrial Service - Primary	7,727,796	7,975,569	3.2%	7,898,827	(1.0%)
8	Industrial Service – Coincident Peak - Primary	4,671,040	4,553,382	(2.5%)	5,037,568	10.6%
9	Electric Heating Schools	44,545	50,756	13.9%	51,568	1.6%
10	General Electric Heating	332,878	361,492	8.6%	370,059	2.4%
11	Outdoor Lighting Services	262,733	396,197	50.8%	304,155	(23.2%)
12	Street Light Services	847,936	920,073	8.5%	934,852	1.6%
13=Sum 1–12	**Total**	**$80,717,356**	**$88,453,204**	**9.6%**	**$88,459,774**	**0.0%**

(1) See Attachment JAM-3, p. 17.

Q34. IN YOUR OPINION, DOES RP&L'S PROPOSED RATE DESIGN MEET ALL OF THESE MITIGATION OBJECTIVES?

A. Yes, RP&L's phase-in proposal meets all rate design objectives.

Q35. IN YOUR OPINION, ARE RP&L'S PROPOSED RATES, AS MITIGATED, NONDISCRIMINATORY, REASONABLE AND JUST?

A. Yes, in my opinion, RP&L's proposed rates as are nondiscriminatory, reasonable and just. This is true particularly given the amount of time that has passed between rates cases, and the fact that RP&L is proposing to completely forego millions of dollars in revenue to which it would otherwise be entitled in order to mitigate the impact to customers.

VIII. RESIDENTIAL RATE STRUCTURE

Q36. HOW IS THE PROPOSED NEW RESIDENTIAL RATE STRUCTURE DIFFERENT THAN RP&L'S CURRENT RESIDENTIAL RATE?

A. Although the COSS indicates a 25.9% increase for this customer class, RP&L proposes to cap the annual increase to 5% over the three year implementation period. This results in a 15.8% rate increase for the residential class at the end of Phase 3, rather than a 25.9% rate increase.

Q37. PLEASE DESCRIBE RP&L'S CURRENT RATE DESIGN AND CHARGES APPLICABLE TO THE RESIDENTIAL ELECTRIC SERVICE CUSTOMER CLASS ("RS TARIFF").

A. RP&L's current Residential Electric Service rate structure is a three-tier declining block structure where compared to the first tier rate of a $0.06492, a $0.01583 per kWh discount is available for incremental monthly energy use above 350 kWh and $0.01929 per kWh discount is available for incremental monthly energy use above 1,500 kWh. The current rate structure is shown in Table JAM-10.

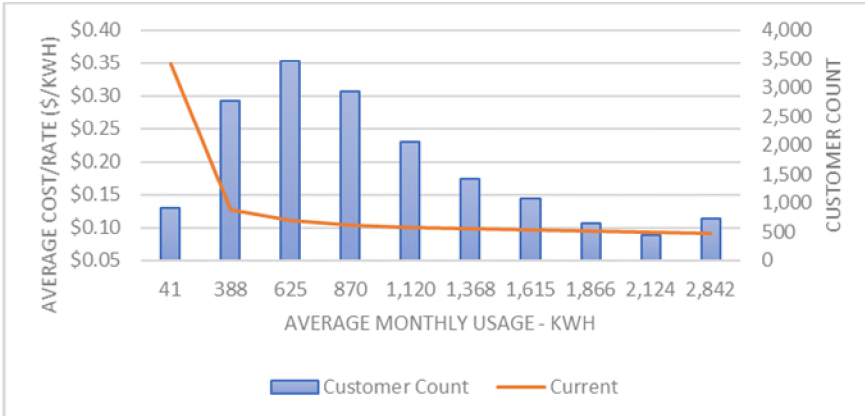
Table JAM-10
Residential Electric Service Current Rate

Line No.	Component	Units	Current Rate
1	**Facilities Charge**	$/Month	10.00
2	**Energy Charge**		
3	First 350 kWh	$/KWH	0.06492
4	Next 1,120 kWh	$/KWH	0.04909
5	Over 1,500 kWh	$/KWH	0.04563
6	**KWH ECA(1)**		
7	Quarter 1	$/KWH	0.03933
8	Quarter 2	$/KWH	0.03650
9	Quarter 3	$/KWH	0.03436
10	Quarter 4	$/KWH	0.04199

(1) Comparison of current rates include an annual weighted ECA based on historical ECA charged during the study period.

Declining block rate structures provide an incentive to customers to use more electricity as the average rate declines with usage. The histogram shown in Figure JAM-3 shows the average monthly energy use of RP&L residential customers. The histogram indicates that the majority of residential customers have monthly energy consumption ranging from about 400 to 1,100 kWh per month. The line on the graph shows the average effective rate a residential customer would pay under the current rate structure. As monthly energy usage increases, the average rate decreases. High energy users pay less than $0.10 per kWh whereas those customers using approximately 400 kWh per month pay about $0.13 per kWh.

Figure JAM-3
Average Annual Monthly Energy Use of RP&L Residential Customers[1]



(1) See Attachment JAM-6.

The current rate structure runs counter to RP&L's desire to provide a conservation pricing signal to residential customers.

Q38. HOW DOES THE COST TO SERVE RESIDENTIAL CUSTOMERS COMPARE TO THE CURRENT RATE STRUCTURES DESIGNED TO RECOVER THOSE COSTS?

A. As shown in Table JAM-5, the Residential Electric Service class is below COSS results by 25.9%. Contributing to this result is lower monthly load factors of residential customers and high coincidence with the system peak demand. The COSS study relies on an average sample of 2,487 residential customers with AMI meters. Meter data was accumulated from January 2018 through September 2019. This data can be found in the RP&L Load Research in Attachment JAM-2, page 149. This data indicates that customer monthly load factors vary from 18% to 29% and that the class is highly coincident with the monthly system peaks as shown in Table JAM-11 below.

Table JAM-11
Residential Electric Service AMI Data[1]

Line No.	Month	LF[2]	NCP:SMD[3]	CP:NCP[4]
1	Jan	29%	46%	97%
2	Feb	27%	38%	94%
3	Mar	25%	38%	91%
4	Apr	20%	34%	89%
5	May	18%	35%	88%
6	Jun	20%	40%	87%
7	Jul	24%	41%	87%
8	Aug	22%	41%	90%
9	Sep	21%	41%	89%
10	Oct	20%	33%	90%
11	Nov	25%	39%	97%
12	Dec	27%	38%	100%

(1) See Attachment JAM-2, p. 144.

(2) Monthly Load Factor (LF) is the sample average for each month. Load factor is calculated by comparing the customers' peak 30-minute demand compared to the average demand over the same period.

(3) the SMD:NCP ratio reflects the relationship between the class monthly peak compared to the customer maximum demand (or for the class the Sum of Maximum Demands (SMD)) (NCP/SMD)

(4) The CP:NCP ratio reflects the relationship between the system peak to the class peak (CP/NCP)

When the CP:NCP ratio is 100%, the timing of the Residential Electric Service class peak is the same as the system peak. These usage characteristics drive the COSS results.

With the class annual revenue target set at 5% annually as a mitigation step, a second consideration is cost recovery from customers in the class. Customer load factor is an important consideration in rate design as customers with higher load factors have a lower average cost of service. Because higher load factor customers use more energy per unit of demand, demand-related costs, which are fixed in nature, are recovered over more energy. Higher load factor customers use utility plant investment more efficiently than lower load factor customers. As a result, the average cost of service is lower because a unit of fixed costs is recovered over more kWh. For RP&L, this relationship aligns well with customer classes that measure customer demand and have demand charges. A rate structure with demand and energy components measure customer monthly load factor and render a charge that rewards higher load factor customers with a lower rate.

However, for classes where demand in not measured, like the Residential Electric Service class, it is difficult to reflect this cost of service differential in an energy only rate design. A declining block rate is an attempt to reflect this cost of service relationship, but because demand is not measured in kW, the size of the blocks are arbitrary and poorly represent customer load factor. The size of a residence is more important than the efficient use of electricity; therefore, it is possible for a large residence with a low load factor to have greater energy usage than a small residence with a high load factor. Although a small, high load factor residence uses electricity more efficiently than the larger residence, the larger residence is rewarded with a lower average rate only because they are large in size. For this reason, and the obvious pricing signal to use more electricity than less, RP&L's proposed Residential Electric Service rate eliminates the current declining blocks and replaces the blocks with a single energy rate.

Q39. PLEASE DESCRIBE RP&L'S PROPOSED CHANGES TO THE RS TARIFF.

A. RP&L's proposed Residential Electric Service rate structure gradually moves overall class revenues towards COSS and eliminates the current three tier declining rate structure. Proposed Residential Electric Service rates compared to the current rate are shown in Table JAM-12 below.

Table JAM-12
Proposed Residential Electric Service Rate

Line No.	Component	Units	Current Rate	Phase 1 Rate	Phase 2 Rate	Phase 3 Rate
1	Facilities Charge	$/Month	10.00	11.75	13.75	15.75
2	Energy Charge(1)					
3	First 350 kWh	$/KWH	0.10306	0.10147	0.10175	0.10230
4	Next 1,150 kWh	$/KWH	0.08723	0.09397	0.09800	0.10230
5	All above 1,500 kWh	$/KWH	0.08377	0.08647	0.09425	0.10230

(1) Includes ECA which is the total revenue generated by the quarterly ECAs for the year divided by the total kWh consumed

Over the three-year phase-in period proposed Residential Electric Service rates increased the customer charge from $10.00 per month to $15.75 per month. The energy charge collapses from the current three tier structure to a single energy rate of $0.10230 per kWh. Also, the current ECA charge has been rolled into base rates, thus, for the purposes of rate design, zeroing out the ECA charge. However, it is expected that over the three-year phase-in period, an ECA adjustment will exist depending upon changes in IMPA power costs compared to cost recovery in base rates. Finally, the current declining block structure is gradually phased out over the period.

Q40. DOES RP&L'S PROPOSED RS TARIFF RATE DESIGN IMPACT CERTAIN RESIDENTIAL CUSTOMERS MORE THAN OTHERS?

A. Yes, elimination of the declining block will impact large users of electricity more than small users due to the elimination of the declining block rate structure as shown in Table JAM-13 below.

Table JAM-13
Residential Electric Service Rate Changes (1)

Line No.	Monthly Usage (kWh)	Current	Phase 1	Phase 2	Phase 3	Total
1	400					
2	Average Rate - $/kWh	0.12608	0.12991	0.13566	0.14168	
3	Difference - $/kWh		0.00383	0.00575	0.00602	0.01560
4	Difference - %		3.0%	4.4%	4.4%	12.4%
5	800					
6	Average Rate - $/kWh	0.10665	0.11194	0.11683	0.12199	
7	Difference - $/kWh		0.00529	0.00489	0.00516	0.01534
8	Difference - %		5.0%	4.4%	4.4%	14.4%
9	1200					
10	Average Rate - $/kWh	0.10018	0.10595	0.11055	0.11543	
11	Difference - $/kWh		0.00577	0.00460	0.00487	0.01525
12	Difference - %		5.8%	4.3%	4.4%	15.2%

(1) See Attachment JAM-6

Q41. DOES RP&L'S PROPOSED RS TARIFF RATE DESIGN PROVIDE BENEFITS TO RESIDENTIAL CUSTOMERS?

A. Yes, by moving the Residential Electric Service class closer to cost of service and eliminating the declining block rate structure, RP&L has strengthened a conservation signal to these customers. Given the size of the Residential Electric Service class and the class contribution to the system peak, this signal can help mitigate future infrastructure investment required to meet system reliability. If successful, this will help delay or avoid expensive infrastructure projects in the future to the benefit of all RP&L customers including residential. Proposed rate design is an important initial step in preparing the class for more dynamic future rate structures enabled by RP&L's investment in AMI.

Q42. HOW DOES RP&L'S PROPOSED RESIDENTIAL RATE DESIGN IMPACT LOW-INCOME CUSTOMERS?

A. RP&L does not normally track the income levels of customers and therefore must rely on other agencies to identify customers by income within the RP&L service territory. To understand the impact of proposed residential rates on low-income customers, RP&L requested available information from the Community Action of East Central Indiana which provided Indiana Housing and Community Development Authority ("IHCDA") data on 1,193 residential customers served by RP&L. The data set included residential customers with reported annual incomes of less than or equal to $13,000 and differentiated customers by heating type (electricity, kerosene, liquified petroleum (LP) gas, natural gas, oil and wood). Using this information, RP&L gathered twelve months of electricity usage data for this group of customers. In examining the usage data, one customer with kerosene heating was removed from the sample because of anomalously high annual usage[3] compared to typical residential customers. A summary of the sample statics excluding this customer is shown in Table JAM-14 below.

Table JAM-14
Low Income Sample Statistics (1)

Heat Type	Customer Count.	Average Annual kWh Usage	Sample Annual Average Usage Compared to Residential Class Average Annual Usage (%)(2)
Electricity	517	12,534	6%
LP-Gas	18	9,545	(19%)
Natural Gas	619	8,633	(27%)
Oil	35	10,318	(12%)
Wood	3	7,423	(37%)
Total	1,192	10,399	n/a

(1) – See Attachment JAM-6
(2) – The average annual kWh usage of the residential class is 11,771 kWh.

The usage data indicates that electricity use is dependent on whether customers heat their

[3] One customer in the sample, with kerosene heating, used 26,452 kWh annually which is 125% of the residential class average.

homes with electricity. Compared to the Residential class average, sample electric heating customers use 6% more electricity on an annual basis, However, sample customers that heat with non-electric options, on an annual basis, use 12-37% less than the residential class average. In general, electric consumption of low-income customers included in the sample varies substantially from customer to customer. This result is not surprising as many factors influence electricity use beyond income levels. Therefore, it is difficult to develop a rate design solution that uniformly benefits all low-income customers regardless of usage. However, low-income bill assistance is available to customers through third party agencies such as the Community Action of East Central Indiana.

As indicated in Table JAM-14, low-income customers without electric heat use less electricity than the residential class average. Because RP&L proposes to collapse the current three-tier declining energy block rate structure into a single energy block, lower usage customers will experience a lower cumulative rate increase compared to higher usage customers. As a result, cumulative three-year proposed rate increases for these customers range from 13.7% to 14.4%. Low-income customers with electric heat on average will experience a 15.0% cumulative three-year rate increase under the proposed rates.

IX. TARIFF CHANGES

Q43. IS RP&L PROPOSING TO ADD OR TO REMOVE ANY RATE CLASSES?

A. Yes, in preparation for this rate case, all existing rate classes were evaluated based on customer applicability, interest and the appropriateness of pricing signals. RP&L has added new rate classes associated with Large Power Service, Large Power Services – Coincident Peak, Industrial Service, Industrial Service – Coincident Peak, and Electric Vehicle Charging. What appears to be a new lighting class in Table JAM-15 below, is just a consolidation of RP&L's

currently lighting classes, with the addition of Light Emitting Diodes (LED) lighting service into a single class. There are currently no customers eligible to receive service under Large Power Service – Primary, Industrial Service – Secondary, and Industrial Service – Coincident Peak – Secondary classes. The introduction of a customer charge to Large Power Service and Industrial Service customer classes is an important addition to the rate structure; and given the size of these customers this structural change has a minor impact on a customer's monthly electricity bill. RP&L is eliminating Large Power Service – On/Off Peak (to be replaced by the LPS Primary and Secondary Coincident Peak classes), Industrial Service – On/Off Peak (to be replaced by the IS Primary and Secondary Coincident Peak classes), Peak Management Credits, and the PJM-DRS-Emergency rider due to lack of customer interest and/or no customers presently being served in the class. The Customer Specific Contracts tariff and three riders associated with Net Metering, Economic Development, and Qualifying Facilities will remain substantively unchanged. These additions and deletions to the tariff classes are summarized in Table JAM-15 below:

Table JAM-15
Tariff Class Comparison – Current to Proposed

Line No.	Old Tariff	New Tariff
1	Appendix A - Energy Cost Adjustment (and 4Q 2018)	Modified to agree with new rate classes
2	Appendix B - Non-Recurring Charges	Updated
3	Residential Electric Service	Updated
4	Commercial Lighting Service	Updated
5	General Power Service	Updated
6	Large Power Service	Updated and split into Primary and Secondary
7	Not Applicable ("NA")	-Large Power Service Secondary
8	NA	-Large Power Service Primary
9	Large Power Service, On/Off Peak	Deleted
10	Large Power Services, Coincident Peak	Updated and split into Primary and Secondary
11	NA	-Large Power Service Secondary Optional Coincident Peak Service
12	NA	-Large Power Service Primary Optional Coincident Peak Service
13	Industrial Service	Updated and split into Primary and Secondary
14	NA	-Industrial Service Secondary
15	NA	-Industrial Service Primary
16	Industrial Service, On/Off Peak	Deleted
17	Industrial Service, Coincident Peak	Updated and split into Primary and Secondary
18	NA	-Industrial Service Secondary Optional Coincident Peak Service
19	NA	-Industrial Service Primary Optional Coincident Peak Service
20	Transmission Service	Updated
21	Transmission Service, Coincident Peak	Updated
22	Customer Specific Contracts	No Substantive Change
23	Outdoor Lighting Services	Updated and consolidated into Lighting Service
24	Municipal Street Lighting Services	Updated and consolidated into Lighting Service
25	Street Light Services	Updated and consolidated into Lighting Service
26	NA	Lighting Service
27	Electric Heating Schools	Updated
28	General Electric Heating	Updated
29	NA	Electric Vehicle Charging Pilot Program
30	Peak Management Credits	Deleted
31	Rider IS - PJM-DRS-Emergency	Deleted
32	Rider NM - Net Metering	No Substantive Change
33	Rider ED - Economic Development	No Substantive Change
34	Rider QF - Qualifying Facilities	No Substantive Change

Q44. WHY DOES THE PROPOSED TARIFF CONTAIN A PLACEHOLDER FOR THE ENERGY COST ADJUSTMENT RIDER?

A. RP&L anticipates that proposed rates will become effective in or near January 2021. In this filing, rate design has included Test Year IMPA costs in the base rate resulting in a zero ECA for all classes. Given the new rate structure, RP&L anticipates an ECA filing in advance of the effective date of new rates that will reflect actual IMPA power costs as reconciled with ECA revenue and costs included in the current rate structure. Ms. Tomczyk discusses the transition from the current to the proposed ECA in her direct testimony.

Q45. HAVE YOU CALCULATED AN AVERAGE BILL UNDER THE PROPOSED RATE STRUCTURE?

A. Yes, for each rate class, Attachment JAM-3, page 2 includes a comparison of average bills at the end of each of the three phases for each of the tariffed rate classes.

Q46. HOW DO RP&L'S PROPOSED RATES AT THE END OF THE THIRD PHASE COMPARE TO THE RATES OF SURROUNDING UTILITIES?

A. RP&L's proposed rates at the end of the third phase still remain very favorable when compared to surrounding utilities, as indicated by Table JAM-16 below.

Table JAM-16(1)
Comparison of Monthly Electric Bills

Consumption		RPL Current Rates	RPL New Rates at End of Phase 3 (Est. 2023)	Duke Energy IURC Cause 45253 Proposed (2020)	Whitewater Valley REMC Current (2019)	RPL New Rates at End of Phase 3 compared to Duke Energy IURC Cause 45253	RPL New Rates at End of Phase 3 compared to Whitewater Valley REMC
Residential Bills							
	500 kWh	$59.15	$66.90	$80.98	$85.49	(17.4%)	(21.7%)
	1,000 kWh	$102.77	$118.05	$143.59	$137.87	(17.8%)	(14.4%)
	1,500 kWh	$146.38	$169.20	$200.20	$190.26	(15.5%)	(11.1%)
	2,000 kWh	$188.26	$220.35	$256.82	$242.64	(14.2%)	(9.2%)
Small Commercial/ General Service							
	3,000 kWh	$383.30	$383.90	$408.53	$364.81	(6.0%)	5.2%
	7,500 kWh	$728.92	$816.97	$894.12	$799.60	(8.6%)	2.2%
	15,000 kWh	$1,458.90	$1,560.95	$1,597.71	$1,557.25	(2.3%)	0.2%
	30,000 kWh	$2,668.20	$3,276.54	$3,169.17	$3,052.55	3.4%	7.3%
Large Commercial/ Industrial							
150 kW	60,000 kWh	$5,291.25	$5,858.38	$6,318.18	$6,116.85	(7.3%)	(4.2%)
300 kW	120,000 kWh	$10,582.50	$11,521.51	$12,610.10	$12,163.70	(8.6%)	(5.3%)
1,000 kW	400,000 kWh	$34,770.81	$37,662.71	$39,009.71	$38,786.40	(3.5%)	(2.9%)
5,000 kW	2,500,000 kWh	$191,627.01	$201,457.56	$233,901.28	$215,403.03	(13.9%)	(6.5%)

(1) – See Attachment JAM-7.

When compared to Duke Energy and Whitewater Valley REMC, RP&L's phase three rates, which are expected to be effective in 2023, compare favorably. Depending upon consumption level, Residential and Large Commercial/Industrial rates are between 9-22% and 3-14% lower respectively. Compared to Duke Energy's 2020 rate proposal, again depending upon consumption level, Small Commercial rates are between 9% lower to 3% higher. Compared to Whitewater Valley REMC current rates, Small Commercial rates are between 0 - 7% higher.

Q47. ARE THERE ANY OTHER RATE CLASSES THAT HAVE CHANGES WHICH YOU WOULD LIKE TO HIGHLIGHT?

A. Yes, the General Power Service rate structure is being restructured so that it will have a new demand component, which more accurately reflects cost of service for fixed costs. General Power Service currently has an energy-only rate, which as I explain below, does not send appropriate price signals to customers.

Q48. PLEASE DESCRIBE PROPOSED CHANGES TO THE GENERAL POWER SERVICE RATE STRUCUTURE.

A. The current General Power Service rate structure is a transitional rate structure with a four-tier declining energy block and a two-tier inclining demand block, where the first 25 kW of demand is free. The current rate structure is complex and benefits low load factor customers because of the very low demand charges. Customers qualify for this class when maximum monthly demands are greater than 11 kW. Customers with maximum monthly demand less than or equal to 11 kW qualify for the Commercial Lighting Service customer class. The Commercial Lighting Service class is essentially an energy rate similar to Residential Electric Service. Given the clear distinction between the Commercial Lighting and General Power Service classes, RP&L proposes to simplify the rate structure of the current General Power Service rate into a traditional demand and energy rate similar to all other commercial classes. With consideration to customer bill impacts associated with migrating from the current rate structure to the proposed rate structure, RP&L proposes to change the rate structure gradually over the three phases as follows in Table JAM-17.

Table JAM-17
General Power Service Rate [1]

Line No.	Component	Units	Current Rate	Phase 1 Rate	Phase 2 Rate	Phase 3 Rate
1	Facilities Charge	$/Bill	20.00	38.00	55.50	73.00
2	Energy Charge[1]					
3	First 500 kWh	$/KWH	0.11534	0.10752	0.09291	0.07832
4	Next 1,500 kWh	$/KWH	0.09859	0.10085	0.08958	0.07832
5	Next 3,000 kWh	$/KWH	0.09389	0.09419	0.08624	0.07832
6	Over 5,000 kWh	$/KWH	0.08868	0.08752	0.08291	0.07832
7	Demand Charge					
8	First 25 kW	$/KW	0.00	1.40	3.95	6.50
9	Over 25 kW	$/KW	2.80	2.80	4.65	6.50
10	Substation Discount	$/KW	0.39	0.53	0.53	0.53

(1) See Attachment JAM-3, p. 20.

Proposed rates gradually eliminate the four-tier declining block energy rate and introduce demand charges of all customers in the class. By phase three, the General Power Service rate has a single demand and energy charge which yields a rate structure that is similar to the rate structures of other RP&L commercial and industrial customer classes. Compared to other commercial and industrial rate classes, General Power Service demand charges are much lower, giving consideration to the current rate structure and RP&L's commitment to gradualism in rate design.

Q49. HAVE YOU INCLUDED CLEAN AND REDLINED VERSIONS OF THE NEW TARIFF?

A. Yes, the clean version of the proposed tariff is included as Attachment JAM-4, and the redlined version is included as Attachment JAM-5.

X. SUMMARY AND CONCLUSION

Q50. PLEASE PROVIDE A SUMMARY OF YOUR RECOMMENDATIONS.

A. In summary, I recommend the IURC approve the following:

1. The COSS as presented herein and recommended changes to RP&L's customer classes including the creation of new Large Power, Industrial and Transmission classes that uniformly offer services to customers that differentiate between delivery voltage and time-of-use.
2. The three-year phase-in plan with recommended class revenue targets.
3. Rate design as proposed for all customer classes.
4. Tariff revisions that not only address rates and charges for current and new customer classes but also update and refine terms of service.

Q51. 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.

Joseph A. Mancinelli

NewGen Strategies & Solutions

Joseph Mancinelli
President & CEO
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Mr. Joseph Mancinelli has over 30 years of experience as a utility consultant to the public utility industry and serves as President & CEO of NewGen Strategies and Solutions, LLC (NewGen). NewGen offers a wide range of management, planning, and engineering economic services to consumer-owned and public power clients. His direct experience includes strategic and business planning, cost of service and rate design analyses, performance management, economic analyses, asset valuation, and revenue bond financing. He regularly advises senior management teams, utility boards, city councils, attorneys, and end-users. Additionally, he has taught cost of service and rate design concepts through numerous presentations, seminars and classes in association with Electric Utility Consultants, Inc., various cooperative organizations and the American Public Power Association.

Education

He has a Master of Business Administration in Finance from the University of Colorado and a Bachelor of Science in Geophysical Engineering from the Colorado School of Mines.

Electric Cost of Service and Rate Design

Mr. Mancinelli has considerable experience leading project teams in the review and establishment of utility revenue requirements, development of cost of service analyses and retail and wholesale rate design. He works with clients and stakeholders in the understanding of cost of service and rate design principles and assists clients in the development of the underlying policies and principals important in the rate setting process. He has worked for clients across the country. Clients include wholesale and retail electric utilities, various stakeholder groups, public utility commissions and large consumers of electricity. A sample of Mr. Mancinelli’s electric cost of service and rate design clients include the following:

- Austin Energy, Texas
- Bose McKinney & Evans, LLP
- Bryan Texas Utilities, Texas
- Cleveland Public Power, Ohio
- Continental Divide, New Mexico
- CPS Energy, Texas
- Deseret Power Cooperative, Utah
- Estes Park Power & Light, Colorado
- Fort Collins Utilities, Colorado
- Farmington Electric Utility System
- City of Garland Power and Light, Texas
- GEUS, Texas
- HNTB Corporation
- Keys Energy Services, Florida
- Lafayette Utilities System, Louisiana
- Lloyd Gosselink Rochelle & Townsend, P.C.
- Lubbock Power and Light, Texas
- Nebraska Public Power District
- New Braunfels Utilities, Texas
- Plains Electric Generation and Transmission Cooperative, Inc., New Mexico (now Tri-State)
- Platte River Power Authority, Colorado
- Richmond Power & Light, Indiana
- Tri-State Generation & Transmission Association, Inc., Colorado
- U.S. Army, Huntsville, Alabama
- United Power Electric Cooperative, Colorado
- Navajo Tribal Utility Authority
- Weatherford Municipal Utilities, Texas

Expert Witness and Litigation Support

Mr. Mancinelli has provided expert testimony for over 20 years regarding electric utility cost of service, rate design, and ratemaking issues before state and local regulatory bodies and courts. He has national experience providing litigation support regarding ratemaking matters at wholesale and retail levels in Alaska, California, Colorado, Guam, Indiana, Michigan, Nebraska, New Mexico, Nevada, North Carolina, Texas, and Utah.

A list of his testimony experience is as follows:

Record of Testimony Submitted by Joseph A. Mancinelli

Utility	Proceeding	Subject	Before	Client	Date
1. Indiana Michigan Power Company	Cause No. 45235	Petition of Indiana Michigan Power Company for authority to increase its rates and charges for electric utility service.	Indiana Utility Regulatory Commission	City of Fort Wayne, City of Marion, and Marion Municipal Utilities	2019
2. Pacific Gas & Electric Company	Application No. 18-12-009	Application of Pacific Gas & Electric Company (U 39-M) for Authority, Among Other Things, To Increase Rates for Electric and Gas Service Effective on January 1, 2020	Public Utility Commission of the State of California	Joint Community Choice Aggregators	2019
3. Farmington Electric Utility System	Docket Nos. QF19-1082-001, QF19-1083-001, QF19-1084-001	Response to April 19, 2019 Petition for Enforcement under the Public Utility Regulatory Policies Act of 1978	Federal Energy Regulatory Commission	City of Farmington, New Mexico	2019
4. Bryan Texas Utilities	Docket No. 48123	Application of Bryan Texas Utilities for Interim Update of Wholesale Transmission Rates Pursuant to Substantive Rule 25.192(g)(1)	Public Utility Commission of Texas	Bryan Texas Utilities	2018
5. Southern Indiana Gas and Electric Company D/B/A Vectren Energy Delivery of Indiana, Inc.	Cause No. 43354 MCRA 21	Verified Petition of Southern Indiana Gas and Electric Company D/B/A Vectren Energy Delivery of Indiana, Inc. ("Company") For: (1) Approval of a MISO Cost and Revenue Adjustment for Electric Service in Accordance with the Order of the Commission in Cause No. 43111 Effective August 15, 2007 and Cause No. 43839 Dated April 27, 2011 Pursuant to J.C. § 8-1-2-42(A); and (2) Authority to File for MISO Cost Revenue Adjustments on an Annual Basis as Opposed to Semi-Annually	Indiana Utility Regulatory Commission	SABIC Innovative Plastics Mount Vernon, LLC	2017
6. Duke Energy Progress, LLC	Docket No. E-2, Sub 1142	Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	North Carolina Utilities Commission	U.S. Department of Defense and all other Federal Executive Agencies	2017
7. Nebraska Public Power District	Section 70, Article 13 Arbitration Panel	Proper Recovery of Post Retirement Benefits in Wholesale Rates	Nebraska Cities vs. Nebraska Public Power District	Nebraska Public Power District	2017

Record of Testimony Submitted by Joseph A. Mancinelli

Utility	Proceeding	Subject	Before	Client	Date
8. Northern Indiana Public Service Company	Cause No. 44733-TDSIC-1	Transmission, Distribution, and Storage System Improvement Charge	Indiana Utility Regulatory Commission	United States Steel	2016
9. Austin Energy	N/A	Austin Energy’s Tariff Package: 2015 Cost of Service Study and Proposal to Change Base Electric Rate	City of Austin Impartial Hearing Examiner	Austin Energy	2016
10. Northern Indiana Public Service Company	Cause No. 44688	Interruptible Demand Credits and Cost of Service	Indiana Utility Regulatory Commission	United States Steel	2016
11. Bryan Texas Utilities	Docket No. 44467	Application of Bryan Texas Utilities for Interim Update of Wholesale Transmission Rates Pursuant to Substantive Rule 25.192(g)(1)	Public Utility Commission of Texas	Bryan Texas Utilities	2015
12. Lower Colorado River Authority	Cause No. 121-001-B	Damages Associated with Wholesale Pricing Practices	District Court of Kerr County, Texas (198th Judicial District)	City of Kerrville, acting by and through Kerrville Public Utility Board	2014-2015
13. GEUS	Docket No. 42581	Application to Change Rates for Wholesale Transmission Service	Public Utility Commission of Texas	GEUS	2014
14. Bryan Texas Utilities	Docket No. 41920	Application of Bryan Texas Utilities for Interim Update of Wholesale Transmission Rates Pursuant to Substantive Rule 25.192(g)(1)	Public Utility Commission of Texas	Bryan Texas Utilities	2013
15. Lower Colorado River Authority	Cause No. D-1GN-12-002156	Damages Associated with Wholesale Pricing Practices	District Court of Travis County, Texas (261st Judicial District)	Central Texas Electric Cooperative, Inc., Fayette Electric Cooperative, Inc., and San Bernard Electric Cooperative, Inc.	2013-2014
16. Austin Energy	SOAH Docket No. 473-13-0935 PUC Docket No. 40627	Petition by Homeowners United for Rate Fairness to Review Austin Rate Ordinance No. 20120607-055	Public Utility Commission of Texas	On behalf of the City of Austin D/B/A Austin Energy	2013
17. Guam Power Authority	Docket No. 11-09	Support of Comprehensive Rate Case	Guam Public Utilities Commission	Guam Power Authority	2012
18. Brownsville Public Utilities Board	Docket No. 38556	Application to Change Rates for Wholesale Transmission Service	Public Utility Commission of Texas	Brownsville Public Utilities Board	2010

Record of Testimony Submitted by Joseph A. Mancinelli

Utility	Proceeding	Subject	Before	Client	Date
19. Rocky Mountain Power	Docket No. 09-035-23	Testified regarding Rocky Mountain Power's Cost of Service Analysis	Utah Public Utilities Commission	Utah Division of Public Utilities	2009
20. GEUS	Docket No. 37180	Support Application to Change Rates for Wholesale Transmission Service	Public Utility Commission of Texas	GEUS	2009
21. Chugach Electric	Docket No. U-06-134	Revenue Requirement, Cost of Service Allocation, Class, and TIER Issues	Regulatory Commission of Alaska	Alaska Electric & Energy Coop/Homer Electric Association	2007
22. Sierra Pacific Power Company	Docket No. 05-10003	In Support of Reductions to Sierra Pacific Revenue Requirement and Modification to the Sierra Pacific Marginal Cost of Service Study	Public Utilities Commission of Nevada	Nevada Resort Association	2006
23. Brownsville Public Utilities Board	Docket No. 32905	Testified in Support of Transmission Costs	Texas Public Utilities Commission	Brownsville Public Utilities Board	2006
24. Cherryland Electric Cooperative vs. Traverse City Light & Power	Case No. U-13716	Evaluating Cost Basis for Proposed Large Resort Service Tax	Michigan Public Service Commission	Traverse City Light & Power	2004
25. Cherryland Electric Cooperative vs. Traverse City Light & Power	Case Nos. U-12844 and U-13071	Testified Against Damages Associated with Loss of Large Retail Load to Competing Utility	Michigan Public Service Commission	Traverse City Light & Power	2002
26. Plains Electric Generation & Transmission Cooperative	Docket No. 2797	Electric System Cost of Service and Rate Study	New Mexico Public Utilities Commission	Plains Electric Generation and Transmission Cooperative	1998
27. Environmental Protection Agency	Civil Action 96-D-2698	Radium Storage Fees	United States District Court of the District of Colorado	City and County of Denver	1997
28. Greenville Electric Utility System	Docket No. 15812	Unbundled Transmission Cost of Service/Transmission Rate Filing Compliance with Substantive Rule 23.67	Public Utility Commission of Texas	Greenville Electric Utility System	1996
29. El Jardin Water Supply Corporation	Docket No. 9013-M	Water System Revenue Requirement and Allocated Cost of Service Study	Texas Natural Resources Commission	Public Utilities Board of Brownsville, Texas	1992-1993