Guide to the Electric Class Cost of Service Study (CCOSS)
Northern States Power Company

I. Overview

Simply stated, the purpose of the Northern States Power Company (NSP) electric Class Cost of Service (CCOSS) is to allocate ***joint*** and ***common*** costs to the designated "classes" of service such as Residential, Non-Demand C&I, and Demand C&I. For example, generation capacity costs are "joint" between time periods and overhead costs such as management, are "common" to multiple functions, such as distribution, transmission, and generation. The CCOSS also assigns ***direct*** costs (e.g., a dedicated service extensions or dedicated substations), that may be associated with providing service to a particular customer from a specific class of service. The objective of the CCOSS is to make these cost ***allocations*** and ***assignments*** based on identifiable service requirements (e.g., kWh energy requirements and kW capacity requirements), which are the drivers of the costs.

The two basic types of costs are: (1) capital costs associated with investment in generation, transmission, and distribution facilities and (2) on-going expenses such as fuel used to produce energy, labor costs, and other operating expenses. The end result is an allocation of the total utility costs (i.e., the revenue requirements) to customer classes according to each class' share of the capacity, energy, and customer service requirements.

II. Major Steps of the Class Cost of Service Study

A class cost of service study begins with a detailed documentation of the numerous budgetary elements of the total revenue requirement for the jurisdiction in question. The detailed jurisdictional revenue requirements are the data inputs to the CCOSS. At a high level, the CCOSS process consists of the following three basic steps:

1. <u>Functionalization</u> – The identification of each cost element as one of the basic utility service "functions" (e.g., generation, transmission, distribution, and customer).
2. <u>Classification</u> – The classification of the functionalized costs based on the billing component/determinant that each is associated with (e.g., kWs of capacity, kWhs of energy, or number of customers).
3. <u>Allocation</u> – The allocation of the functionalized and classified costs to customer classes, based on each class' respective service requirements (e.g., kWs of capacity, kWhs of energy, and the number of customers, expressed in terms of a percentage of the total jurisdiction requirement).

III. Step 1: Functionalization

Functionalization is the process of associating each of the numerous detailed elements of the total revenue requirement with functions (and sometimes sub-functions) of the electric utility system. Costs must be first functionalized because each class' service requirement tends to have different relative impacts on each service function. As such, it is necessary to develop separate sub-parts of the total revenue requirement for each function (and sometimes sub-function). The four basic functions and the associated sub-functions are shown in the table below:

Function	**FERC Accounts**	**Sub-Function**	**Description**
Generation	120, 310-346, 500-557	"Energy-related"	Includes the fixed costs of generation plant investment and purchase capacity costs, which have been stratified as "energy-related."
		Summer "capacity-related."	Includes the fixed costs of generation plant investment and purchase capacity costs stratified as "capacity-related" and which are associated with the system summer peak load requirements.
		Winter "capacity-related."	Includes the fixed costs of generation plant investment and purchase capacity costs stratified as "capacity-related" and which are associated with the system winter peak load requirements.
		On-Peak Energy	Includes costs for fuel and purchases of energy for on-peak hours.
		Off-Peak Energy	Includes costs for the fuel and purchases of energy for off-peak hours.
Transmission	350-359, 560-579	None	Includes costs of transmission lines used to transport power from its origin generation stations or delivery points to the high voltage side of the distribution substations.
Distribution	360-368, 580-598	Distribution Substations	Includes costs of the facilities (e.g., transformers and switch gear) between the transmission and distribution systems.
		Primary Distribution System "Capacity."	Includes costs of the "capacity" portion (as distinguished from the "customer" portion) of primary voltage conductors, transformers and related facilities.
		Secondary Distribution System "Capacity."	Includes costs of the "capacity" portion (as distinguished from the "customer" portion) of secondary voltage conductors, transformers, customer services and related facilities.
Customer	360-369, 580-598, 901-916	"Customer" portion of the Primary and Secondary Systems	Includes costs for the "customer" portion of primary and secondary conductors, transformers, customer service drops, related facilities and the costs of metering.
		Energy Services	Includes costs for meter reading, billing, customer service and information, and back-office support.

A. Generation Cost Stratification

Stratification is the term used to identify the part of the CCOSS process used to separate or "stratify" fixed generation costs into the necessary "capacity-related" and "energy-related" sub-functions. The "capacity-related" portion of the fixed costs of owned generation is based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable peaking plant (the generation source with the lowest capital cost). The percent of total generation costs that exceeds the cost of a comparable peaking plant are sub-functionalized as "energy-related." This second portion of the fixed generation costs is "energy-related" because these costs are in excess of the "capacity-related" portion and as such were not incurred to obtain capacity but rather were incurred to obtain the lower cost energy that such plants can produce.

For example, the plant stratification analysis used in the current rate case is shown in the table below. It compares the current dollar replacement costs of each plant type, to develop stratification percentages.

Plant Type	$/kW	Capacity Ratio	Capacity %	Energy %
Peaking	$1,552	$1,552 / $1,552	100.0%	0.0%
Nuclear	$7,312	$1,552 / $7,312	21.2%	78.8%
Fossil	$4,230	$1,552 / $4,230	36.7%	63.3%
Combined Cycle	$2,336	$1,552 / $2,336	66.4%	33.6%
Hydro	$8,090	$1,552 / $8,090	19.2%	80.8%
Wind	$12,593	$1,552 / $12,593	12.3%	87.7%
Solar	$3,048	$1,552 / $3,048	50.9%	49.1%

This process of "stratifying" the revenue requirements of the generation plant is accomplished by applying these stratification percentages to each component of the revenue requirements (e.g., plant investment, accumulated depreciation, deferred income taxes, construction work in progress (CWIP), etc.), for each generation plant type.

IV. Step 2: Cost Classification

The second step in the CCOSS process is to classify the functionalized costs as being associated with a measurable customer service requirement which gives rise to the costs. The three principal service requirements or billing components are:

1. Demand – Costs that are driven by customers' maximum kilowatt (kW) demand.
2. Energy – Costs that are driven by customers' energy or kilowatt-hours (kWh) requirements.
3. Customer – Costs that are related to the number of customers served.

The table below shows how each of the functional and sub-functional costs was classified:

Function/Sub-Function	Cost Classification		
	Demand	**Energy**	**Customer**
Summer Capacity-Related Fixed Generation	X		
Winter Capacity-Related Fixed Generation	X		
Energy-Related Fixed Generation		X	
Off-Peak Energy (Fuel and Purchased Energy)		X	
On-Peak Energy (Fuel and Purchased Energy)		X	
Transmission	X		
Distribution Substations	X		
Primary Transformers	X		
Primary Lines	X		X
Secondary Lines	X		X
Secondary Transformers	X		X
Service Drops	X		X
Metering			X
Customer Services			X

As shown in the table above, primary lines, secondary lines, secondary transformers, and service drops are classified as both "demand" and "customer" related costs. Costs of these sub-functions are driven by **both** the number of customers on the distribution system and the capacity requirements they place on the system. Two methods that are mentioned in the NARUC manual for performing this cost separation are the Minimum Distribution System method and the Minimum/Zero Intercept method.

The Minimum Distribution System method involves comparing the cost of the minimum size of each type of facility used, to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the "customer" component of total costs, and the "capacity" cost component is the difference between total installed cost and the minimum sized cost.

The Minimum/Zero Intercept method requires significantly more data and analysis than the Minimum Distribution System method. The Minimum/Zero Intercept method requires the analyst to develop installed per unit costs for the most common property unit configurations. Next, the maximum capacity rating (Ampacity for conductors and kVa for transformers) must be determined. Once the above data has been acquired, the statistical analysis technique called linear regression is applied to each property unit. Specifically, the variable "cost per unit" as the dependent variable (Y axis) is regressed on the variable "maximum capacity" as the independent variable (X axis). The point where the regression line crosses the Y intercept is the theoretical "zero load" cost per unit. The zero-intercept cost for a given property unit determines the "customer" component of total costs, and the "capacity" cost component is the difference between total installed cost and the zero-intercept cost.

The Company completed both minimum system and zero intercept studies for all property units except distribution services. Detailed property records on the configuration or footage of distribution service drops are not available. As a result, the Company was not able to conduct a detailed minimum system or zero intercept study for classifying the cost of service drops. As a substitute, a simplified minimum system analysis was conducted.

For each property unit, the table below shows the percent of costs that were classified as customer-related using the Minimum/Zero Intercept method compared to the Minimum Distribution System method. As shown below, for 5 of the 6 property units the Minimum/Zero Intercept method provides a lower customer component, while 1 of the 6 have a lower customer component using the Minimum Distribution System method.

	% of Costs Classified as "Customer" Related	
Equipment Type	**Minimum/Zero Intercept Method**	**Minimum Distribution System Method**
Overhead Lines Primary	24.0%	63.2%
Overhead Lines Secondary	79.9%	96.0%
Overhead Transformers	69.1%	78.0%
Underground Lines Primary	34.7%	63.8%
Underground Lines Secondary	58.6%	100%
Underground Transformers	70.2%	66.7%

In applying the results of the zero intercept and minimum system studies to the proposed CCOSS, the Company used a hybrid of the two methods, such that the Company used the method that provided the lower customer component as shown in the table below.

Property Unit	**% Customer Related**	**% Capacity Related**
Overhead Lines Primary (used Zero Intercept Result)	24.0%	76.0%
Overhead Lines Secondary (used Zero Intercept Result)	79.9%	20.1%
Underground Lines Primary (used Zero Intercept Result)	34.7%	65.3%
Underground Lines Secondary (used Zero Intercept Result)	58.5%	41.5%
Weighted Average for Overhead & Underground Transformers (used Zero Intercept for OH Transformers; used Minimum System for UG Transformers)	68.1%	31.9%

V. Step 3: Cost Allocation to Customer Class (Assignment of Costs to Customer Classes)

The third step in the CCOSS process is allocation, which is the process of assigning (allocating or directly assigning) functionalized and classified costs to customer classes. Generally, cost assignment occurs in one of two ways:

- Direct Assignment - A small but sometimes important portion of costs can be directly assigned to a specific customer of a particular customer class, because these costs can be exclusively identified as providing service to a particular customer. Examples of costs that are directly assigned include:
  - Customer-dedicated transmission radial lines or dedicated distribution substations; and
  - Street lighting facility costs.
- Allocation - Most electric utility costs are incurred in common or jointly in providing service to all or most customers and classes. Therefore, allocation methods have to be developed for each functionalized and classified cost component. The allocation method is based on the particular measures of service that is indicative of what drives the costs.
  - Class allocators (sometimes called allocation strings) are simply a "string" of class percentages that sum to 100%.
  - There are two types of allocators:
    - External Allocators –These are the more interesting allocators that are based on data from outside the CCOSS model (e.g., load research data, metering and customer service-related cost ratios). In general, there are three types of external allocators:
      - Demand-related (sometimes referred to as Capacity) allocators such as:
        - System coincident peak (CP) responsibility or class contribution to system peak (1CP, 4CP or 12CP);
        - Class peak or non-coincident peak; and
        - Individual customer maximum demands.
      - Energy-related allocators such as:
        - kWh at the customer (kWh sales);
        - kWh at the generator (kWh sales plus losses); and
        - kWh energy, weighted by the variable cost of the energy in the hour it is used.
      - Customer-related allocators
        - Number of customers; and
        - Weighted number of customers, where the weights are based on cost of meters, billing, meter-reading, etc.

      Details on the external allocators used in the CCOSS model are shown in Appendix 2.

    - Internal Allocators – These are allocators based on combinations of costs already allocated to the classes using external allocators. These internal allocators are used to assign certain costs, which are most appropriately associated with and assigned to classes by some combination of other primary service requirements, such as kWs demand, kWhs of energy or the number of customers. Examples of internal allocators include:

- Production, transmission, and distribution plant investment – Labeled "PTD" in the CCOSS model.
- Distribution O&M expenses without supervision and miscellaneous expenses – Labeled "OXDTS" in the CCOSS model.

Details on the development of the internal allocators used in the CCOSS model are shown in Appendix 3.

VI. Customer Class Definitions

Ideally, there would be no customer class groupings and cost allocation would reflect the unique costs of each individual customer. Because this is not possible, it is necessary to develop a cost study process that identifies costs of service for groups of customers ("classes") where the customers of the class have similar cost/service characteristics. The basic classes of service employed in the Company's CCOSS are the following:

1. Residential;
2. Non-Demand Metered Commercial;
3. Demand Metered Commercial & Industrial; and
4. Street & Outdoor Lighting.

Also, because of the significantly different distribution-functional requirements of customers within the Demand Metered C&I class, the Company's CCOSS also identifies the cost differences associated with the following distribution-function requirements within this class based on the voltage they are served at:

1. Secondary;
2. Primary;
3. Transmission Transformed; and
4. Transmission.

More detail on customer class definitions is shown in Appendix 1.

VII. Organization of the CCOSS Model

The CCOSS model consists of numerous worksheets which show costs by customer class in Total (as shown on the worksheet tab labeled "RR-TOT") and at the following more detailed levels including Billing Unit, Function and Sub-function as shown below (the label of the worksheet tab in shown in parenthesis below):

1. Billing Unit:

    a. Customer (RR-Cus)
    b. Demand (RR-Dmd)
    c. Energy (RR-Ene)

2. Function and Associated Sub-Function:

   a. Energy (RR-Ene)
      a) On-Peak Energy (RR-On)
      b) Off-Peak Energy (RR-Off)

   b. Generation (RR-Gen_Dmd): Sub-functions include:
      a) Summer Capacity-Related Plant (RR-Summ)
      b) Winter Capacity-Related Plant (RR-Wint)
      c) Energy-Related Plant (RR-Base)

   c. Transmission (RR-Transco)

   d. Distribution (RR-Disco): Sub-functions include:
      a) Distribution Substations (RR-Psub)
      b) Primary Voltage (RR-Prim)
      c) Secondary Voltage (RR-Sec)

   e. Customer (RR-Cus): Sub-functions include:
      a) Service Drops (RR-Svc_Drop)
      b) Energy Services (RR-En_Svc)

In the CCOSS spreadsheet, there is a separate worksheet tab for each of the above billing units, functions, and sub-functions. This multi-level breakdown of costs is useful for designing rates as well as for determining class revenue responsibilities.

VIII. CCOSS Calculations

Listed below are important calculations that are part of the CCOSS model. These calculations occur at the "TOT" layer of the CCOSS as well as each of the "sub-layers" for each billing component, function and sub-function. Showing results at the more detailed billing component, function and sub-function levels is important for rate design purposes, as well as other analyses such as the development of voltage discounts.

A. Rate Base Calculation

Rate Base = Original Plant in Service – Accum Depr – Accum Defer Inc Tax+ CWIP + Other Additions

The above rate base calculation occurs on "TOT" layer as well as each function/sub-function layer.

B. Revenue Requirements Calculation (Class Cost Responsibility)

The Revenue Requirements Calculation (sometimes referred to as the "Backwards Revenue Requirement Calculation) is used to calculate "cost" responsibility for each customer class. This has to be done within the CCOSS model because the JCOSS model does it only at the total jurisdiction level, not by class. The class "cost" responsibility is based on the same return on rate base for each class that is equal to the overall proposed rate of return. In other words, class revenues requirements are calculated to provide the same return on rate base for each customer class. This calculation occurs on the "TOT" layer as well as for each function, sub-function, and billing component after all expenses and rate base items have been allocated. As such, class cost responsibility is available for each function, sub-function, and billing component. This analysis serves a starting point for rate design. The formula is shown below:

Retail Revenue Requirement = Expenses (less off-setting credits from Other Operating Revenues)

+

(((% Return on Invest x Rate Base) - AFUDC - Fed Credits) x 1 / (1 - Fed T) - Fed Section 199 Deduc x Fed T/(1-Fed T) - State Credits) x 1 / (1 - State T)

+

(Tax Additions – Tax Deductions) x Tax Rate / (1-Tax Rate)

Where:

Tax Rate = 1 – (1- State T)x (1-Fed T)

Expenses = O&M + Book Depreciation + Real Estate & Property Tax + Payroll Tax
+ Net Investment Tax Credit – Other Retail Revenue – Other Oper. Revenue

Tax Additions = Book Depreciation + Deferred Inc Tax + Net Inv Tax Credit
+ Other Misc Expenses.

Tax Deductions = Tax Depreciation + Interest Expense + Other Tax Timing Diff

C. Total Return and Return on Rate Base (Based on Class Revenue Responsibility)

After rates have been designed and each class' "revenue" responsibility has been determined, the model calculates total return and return on rate base using the following formulas. These calculations are performed at both present and proposed rate levels.

Total $ Return = Revenue – O&M Expenses – Book Depr.
– Real Estate & Property Taxes – Provision for Deferred Inc Taxes – Inv. Tax Credits
– State & Federal Income Taxes + AFUDC

Percent Return on Rate Base = Total $ Return / $ Rate Base

After rates have been designed, the return on rate base is typically different for each customer class. In other words, the resulting class "revenue" responsibility differs from class **"cost"** responsibility.

IX. CCOSS Output

The filed output of the CCOSS model includes the "TOT" worksheet layer of the much larger model. The important output from the functional, sub-functional and billing component layers is presented on pages 2 and 3 of this "TOT" layer. The following table lists what is shown on each CCOSS page when printed.

Final CCOSS Printout "TOT" Worksheet

CCOSS Section	**Page Number**	**Results Detail**	**Line Numbers**
Results Summary	1	Rate Base Summary	1-21
		Income Statement Summary	22-31
	2	**Proposed Cost** Responsibility at Equal ROR (the cost of service) compared to **Present** Rate **Revenue** Responsibility	1-51
	3	**Proposed Cost** Responsibility at Equal ROR (the cost of service) compared to **Proposed** Rate **Revenue** Responsibility	1-54
Rate Base Detail	4	Original Plant in Service	1-52
	5	MINUS Accumulated Depreciation	1-29
		MINUS Accumulated Deferred Income Tax	30-57
	6	PLUS Construction Work in Progress & Other Additions	1-36
		EQUALS Total Rate Base & Common Rate Base	37-38
Income Statement Detail	7	Present and Proposed Revenues	1-26
		MINUS O&M Expenses part 1	27-41
	8	MINUS O&M Expenses part 2	1-34
	9	MINUS Book Depreciation	1-24
		MINUS Real Estate & Property Taxes, Other Taxes	25-51
	10	MINUS Provision for Deferred Income Tax	1-27
		MINUS Investment Tax Credit; Total Operating Expense	28-52
		EQUALS Present and Proposed Operating Income Before Income Taxes	53A 53B
	11 (Income Tax Calcs.)	Tax Additions	31-36
		MINUS Tax Deductions	1-30
		EQUALS Total Income Tax Adjustments	37
		Present and Proposed Taxable Net Income	38A 38B
		Present and Proposed State and Federal Income Taxes	39A 39B
		Present and Proposed Preliminary Return	40A 40B
		AFUDC (from page 12)	41
		Present and Proposed Total Return	42A 42B
Misc Calcs	12	AFUDC	1-25
		Labor Allocator	26-47
Allocator Data	13	Internal Allocators and Associated Data	1-31
	14	External Allocators and Associated Data	1-50

	Customer Class	Rate Codes	kW Size	Voltage Specifications	Costs Not Assigned	Why Costs Not Assigned
1	Residential	E01, E02, E03, E04, E06, E10 (if residential), E11			• Costs directly attributed to and directly assigned to Street Lighting customers • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes.	The listed facilities and their associated costs are not used to provide service to these customers.
2	C&I Non-Demand Metered	E10 (if C&I), E11, E13, E14, E18, E40	< 25 kW		• Costs directly attributed to and directly assigned to Street Lighting customers • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes.	The listed facilities and their associated costs are not used to provide service to these customers.
3	C&I Secondary Voltage	E15, E16, E20, E21, E22	> 25 kW	Secondary	• Costs directly attributed to and directly assigned to Street Lighting customers • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes. • Costs of Underground ("UG") services. C&I customers pay for their own UG services.	The listed facilities and their associated costs are not used to provide service to these customers.
4	C&I Primary Voltage	E15, E16, E20, E21, E22	> 25 kW	Primary	• Costs directly attributed to and directly assigned to Street Lighting customers • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes. • Costs of Secondary Voltage Overhead and Underground Lines that have been classified as either "Customer" or "Capacity" related. • Costs of Secondary Voltage Transformers that have been classified as either "Customer" or "Capacity" related. • Costs of Service Lines that have been classified as either "Customer" or "Capacity" related.	The listed facilities and their associated costs are not used to provide service to these customers.

	Customer Class	Rate Codes	kW Size	Voltage Specifications	Costs Not Assigned	Why Costs Not Assigned
5	Outdoor Lighting	E12, E30, E31, E32, E33			• Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes.	The listed facilities and their associated costs are not used to provide service to these customers.

The table below lists and describes the external allocators used in the Class Cost of Service (CCOSS) model.

Code	Allocator for:	Description	Allocator Rationale & Background
C11	Connection charge revenues	Average monthly customers for the Test Year	Customer connection revenues are driven by number of customer services.
C10	Used to calculate C11	C11 less automatic protective lighting and load management services. C11 less number of customers with a second service.	
C11WAF	Used to calculate C11WA allocator	Customer accounting cost weighting factors. The weighting factor for residential customers is set at 1.0. The weighting factors for other classes are defined relative to costs for residential. E.g., if it cost three times as much to serve a specific class than it does the residential class, its factor would be 3.0.	Weighting factors are set so as to reflect the relative costs of meter reading, billing and providing customer service for different classes of customers. For example, some rate schedules are significantly more complex requiring more sophisticated meter reading capabilities, billing systems and customer service staff.
C11WA	Customer accounting costs	Average monthly customers weighted by each class' relative rating of customer accounting costs: C11 X C11WAF	Customer accounting costs are driven by number of customers and the complexity of their respective rate, billing issues and customer service requirements.
C12	Used to calculate C12WM allocator	Reflects actual number of meters. C11 with an adjusted street lighting customer count. Only selected street lighting rates are metered	
C12WMF	Used to calculate C12WM allocator	Average meter cost for each customer type	
C12WM	Meter costs	Number of meters multiplied by each class' average meter costs: C12 X C12WMF	Metering costs are driven by the number of customers in each class and the respective metering costs.
C61PS	The "customer" (minimum system) portion of primary distribution line costs	Average monthly customers served at primary or secondary voltage. C11 less transmission transformed and transmission voltage customers	The number of customers served at secondary and primary voltages drives the customer related portion of primary distribution line costs. Transmission and Transmission Transformed voltage customers are excluded since they do not use the distribution system.

Code	**Allocator for:**	**Derivation**	**Allocator Rationale & Background**
C62Sec	The “customer” (minimum system) portion of secondary (not primary) distribution line costs	Average monthly customers served at secondary voltage. C61PS less primary voltage customers	The number of customers served at secondary voltage drives the customer related portion of secondary distribution line costs. Transmission and primary voltage customers are excluded since they do not use the secondary distribution system.
C62NL	The “customer” (minimum system) portion of service-line costs.	Adjusted average monthly secondary voltage customers. C62Sec less street lighting and C&I underground customers	The number of secondary customers drives the customer portion of service line costs. C&I underground secondary customers are excluded since they own their services. Lighting customers are excluded since they do not have services.
D60Sub	Distribution substation costs	Class Coincident peak measured at the high voltage side of the Distribution Substation less Class Coincident peak of Transmission Voltage customers	Distribution substation costs are driven by class peak demands, whenever they occur which is generally at times other than the total system peak. Transmission voltage customers are excluded since they do not use the distribution substation.
D61PS	The capacity portion of primary distribution line costs.	D60Sub less Transmission Transformed customer demands, less customer demands served by minimum distribution system and with reduced Residential Space Heating demands to reflect the fact that their summer peak is less than their winter peak.	The driver of primary distribution line costs is the class coincident demands less the minimum system demand of each class. The minimum demand is classified as a customer related cost. Also, transmission and transmission transformed voltage customers are excluded since they do not use the distribution system.
D62Sec	Used to calculate the D62SecL allocator	D61PS less class coincident demands of primary voltage customers	
D62SecL	The capacity portion of secondary distribution line costs	D62SecL equals the average of D62Sec percent and non-coincident (or “individual customer peak”) secondary voltage percent.	Capacity related secondary distribution line costs are driven by both class coincident peak demand and individual customer maximum demand, less the minimum system demand of each class. (The minimum system demand is classified as customer related.) Also, transmission and primary voltage customers are excluded since they do not use the secondary distribution system.

Code	**Allocator For:**	**Derivation**	**Allocator Rationale**
D62NLL	The capacity portion of service-line costs	Non-coincident (or "customer peak") demand for secondary voltage customers, less the customer peak demand for street lighting, area lighting and C&I customers served underground	Capacity related service line costs are driven by individual customer maximum demands less the minimum system demand of each class. (The minimum system demand is customer related.) Transmission voltage, primary voltage and lighting customers are excluded since they do not cause service-related costs. Also excluded are C&I underground customers since they install their own services.
D10S	Summer season portion of capacity-related generation costs	Each class' % contribution to the single summer system peak. Summer months are June through September.	The class contribution to the system summer peak drives the summer portion of capacity-related generation costs.
E8760	Energy-related portion of generation, nuclear fuel capital and generation step-up costs. Also, allocator for fuel, purchased energy and energy-related fixed generation costs.	Class hourly energy (MWH) requirements multiplied by the corresponding hourly marginal energy cost.	The driver of these costs is energy requirements, which is measured by hourly energy requirements weighted by hourly marginal energy costs.

Internal Allocators are those that are determined from data generated within the Class Cost of Service Study (CCOSS). Below is a list of internal allocators that are used within the CCOSS.

Code	**Allocator for:**	**Description**	**Allocator Justification**
C11P10	Expenses and labor related to customer assistance and instructional advertising	This allocator is the average of the Customer-related C11 allocator and the Production Plant investment P10 allocator.	Customer assistance and advertising expenses are driven by # of customers, and since most assistance pertains to helping customers reduce energy use it affects production plant investment.
LABOR	Amortizations, Payroll Taxes and A&G Expenses that are labor related such as Salaries, Pension & Benefits, Injuries & Claims.	Total Labor costs on Page 12 line 47 less A&G Labor on Page 12 line 45. A&G Labor is excluded to avoid a circular reference.	The specified expenses are directly related to Labor costs.
NEPIS	Property Insurance	Electric plant in service less accumulated provision for depreciation	Property insurance is driven by net electric plant in service.
OXDTS	Distribution customer installation expenses and miscellaneous distribution expenses.	All Distribution O&M Expense, except Supervision and Engineering, Customer Install and Miscellaneous. Supervision & engineering expenses are excluded since they are an overhead expense. Customer installation expenses and miscellaneous distribution expenses are excluded to avoid a circular reference. (lines 2 thru 7, 9 and 11 of page 8)	The OXDTS allocator represents the majority of Distribution O&M expenses (excl supervision and customer installation costs) which is a good indicator for miscellaneous distribution expenses.
OXTS	Selected administrative and general expenses such as Office Supplies, General Advertising, Contributions and maintenance of “General” plant.	All O&M costs except Regulatory Expense and any A&G costs, which are the costs to be allocated on OXTS (lines 16, 17 and 23-27 of page 8). These A&G expenses are excluded to avoid circular references	The OXTS allocator includes all O&M expenses except regulatory expense and those A&G items that are allocated with OXTS. Representing most O&M expenses, the OXTS allocator is appropriate for allocating A&G expenses.

Code	Allocator for:	Description	Allocator Justification
P10	Interchange Production Capacity (i.e. fixed) inter-company Revenues. Rate base addition production-related materials and supplies.	Total Production Plant: Original Plant in Service (line 6 of page 4)	Total production plant investment is closely associated with Interchange Agreement Capacity related revenues.
P10WoN	Interchange Production Capacity (i.e. fixed) inter-company Costs	Total Production Plant less Nuclear Fuel: Original Plant in Service. Nuclear fuel is excluded since NSP Wisconsin does not have nuclear plants (Total Production Plant on line 6 of page 4 less Nuclear Fuel on line 5 of page 4)	Since Wisc. does not have nuclear plants, total production plant investment less nuclear fuel investment is a good indicator of Interchange Agreement Capacity related expenses.
P5161A	Used to allocate Step-up sub transmission costs in the Labor Allocator development	Total Generation Step-Up Transformer original plant in service: Tran Gener Step Up (line 9 of page 4) + Distrib Substn Step Up (line 14 of page 4)	Generation step-up plant investment drives step-up generation labor costs.
P61	Distribution Substation O&M expense and Distribution Substation labor	Distribution Plant: Substations Original Plant in Service (line 18, page 4)	Substation plant original investment drives Distribution Substation plant O&M costs and Distribution Substation Labor.
P68	All costs related to Distribution Plant “Line Transformers”	Distribution Plant: Line Transformers Original Plant in Service (line 42 of page 4)	Line transformer plant investment drives all line transformer costs.
P69	All costs related to Distribution Plant “Services”	Customer-Connection “Services” Original Plant in Service (line 45 of page 4)	Distribution “Services” plant investment drives all costs of “Services.”
P73	All costs related to Street Lighting	Street Lighting Original Plant in Service (line 47 of page 4)	Street Lighting plant investment drives all Street Lighting costs. The results of the direct assignment of Street Lighting costs were turned into an allocator, for use elsewhere in the CCOSS.

Code	Allocator for:	Derivation	Allocator Justification
POL	All costs related to Overhead Distribution Lines including Rental costs and Distribution overhead line rent revenues.	Distribution Plant: Overhead Lines Original Plant in Service (line 28 of page 4)	Overhead distribution line plant investment drives all costs related to Overhead Distribution Lines.
PT0	Working Cash	Total Real Estate & Property Taxes (line 48 of page 9)	Working Cash is closely related to Real Estate Taxes.
PTD	All costs related to General Plant and Electric Common Plant	Original Plant Investment: Production + Transmission + Distribution (lines 6, 13 and 48 of page 4)	Total investment in production, transmission and distribution plant is the best allocator for general and common plant.
PUL	All costs related to Underground Distribution Lines	Distribution Plant: Underground Lines Original Plant in Service (line 38 of page 4)	Underground distribution line plant investment drives all costs related to Underground Distribution Lines.
R01	Sales and economic development expenses	Present revenues for the test year	Economic Development expenses are used to retain or enhance the Company's revenues.
RTBASE	Income Tax Addition: Avoided tax interest	Total Rate Base (line 37 of page 6)	Total rate base drives avoided tax interest.
STRATH	Step-up Transformers that are Dedicated to Hydro	Using the current Stratification for Hydro Plants, the allocator is an 81% weighting of the E8760 energy allocator and a 19% weighting of the D10C capacity allocator	Energy vs. capacity weighting of Hydro plants drives Step-up Transformer investment. It applies to just the very small portion of generation step-up assets that are hydro-related and are located on the Distribution system, unlike all of the other generation step-up facilities that are located on the Transmission system.
TD	Transmission and Distribution Materials and Supplies that are Rate Base Additions	Total Transmission and Distribution Original Plant in Service (lines 13 and 48 of page 4)	Total Transmission and distribution plant investment drives investment in miscellaneous transmission and distribution materials and supplies.
ZDTS	Supervision & Engineering and Customer Installation Distribution Labor	All Distribution Labor except Supervision and Engineering and Customer Installation. These items are excluded to avoid a circular reference. (line 42 on page 12, less lines 32 and 39)	Distribution labor (excluding Supervision & Engineering) drives Supervision and Engineering and Customer Installation Labor.

Analysis	Analysis Description	Data Sources and Associated Vintage
E8760 Allocator Development	This allocator is developed by multiplying customer class loads by system marginal energy costs for each hour of the 2024 Test Year. The allocation is the relationship of the annual class totals of these hourly results to the retail total.	1. Test-Year 8760 load shapes for each customer class are developed from 2024 statistically significant class level sample data. 2. Hourly system marginal energy costs are based on the 2024 Test Year forecast from the Commercial Operations area.
Generation Plant Stratification Analysis	Cost stratification is the term used to identify the capital substitution analysis that separates or “stratifies” fixed generation costs into “capacity-related” and “energy-related” categories. The information used for this analysis includes the 2024 replacement costs of NSPM power plants that were developed by the Capital Asset Accounting area, and the corresponding capacity ratings for those plants. This information is used to define the “capacity-related” component for each type of non-peaking generation plant. This capacity component by plant type is recognized by dividing the peaking plant cost per kW by the non-peaking cost per kW. The remaining “energy-related” component by plant type is the percent determined by subtracting the capacity-related percent from 100 percent. This component is sub-functionalized as “energy-related,” because it represents the additional investment above the cost of a peaking plant that is made to obtain lower energy (and total) costs as compared to a peaking plant.	Based on 2024 replacement costs of all NSP Minnesota Company Power Plants.
Customer Accounting Weights	The relative costs by customer class for meter reading, back-office support, customer service and billing were developed based on current budgets and the experience of management in the Billing and Customer Service area. Residential customers are assigned a weight of 1. Based on this analysis, the other customer classes are assigned weights based on the relative differences compared to the residential class.	Based on 2024 actuals with the relative weighting estimates provided by management from the Billing and Customer Service areas.

Analysis	Analysis Description	Data Sources and Associated Vintage
Minimum System Analyses	The Minimum System and Zero Intercept Analyses is used to separate FERC accounts 364-369 into “Demand/Capacity-Related” and “Customer-Related” cost classifications. In 2015 and 2021 the Company conducted a Minimum System study that was updated to 2024 using the Handy Whitman Indices. The Minimum Distribution System method involves comparing the cost of the minimum size of each type of facility used to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the “customer” component of total costs. The “capacity” cost component is the difference between total installed cost and the minimum sized cost. The Zero Intercept method attempts to determine the portion of plant that relates to a hypothetical no load or zero intercept situation. By analyzing the actual costs of 14 years of construction work orders, installed costs per unit (e.g. cost per foot of overhead primary conductor) were obtained for equipment configurations that comprise at least 90% distribution plant in the field. The installed cost was regressed against the load carrying capacity of each equipment configuration. The zero intercept of the regression was used as the minimum system cost. The cost of the minimum size facilities determines the “customer” component of total costs.	Based on an analysis of distribution construction work orders in Minnesota Company that were completed from 2007 to 2020.
Customer Metering Cost per Customer	Customer metering weights are assigned to each class based on the actual replacement costs of meters, current transformers (CTs) and voltage transformers (VTs) for each customer in each class. An inventory of the meter model, CT model and VT model installed for each customer by customer class was obtained from the Company’s Meter Data Management System ("MDMS"). Metering staff provided current replacement costs for each meter model, CT model and VT model. Weighted customer metering costs including the cost of CTs and VTs were then calculated for each customer and rolled up for each customer class.	Based on a 2024 inventory of meter models, CT models and VT models for each customer. Meter, CT and VT replacement costs are for 2024.

Analysis	**Analysis Description**	**Data Sources and Associated Vintage**
Classification of Other Production O&M Costs	Consulted with Xcel Generation Cost modeling staff to identify Other Production O&M expenses that vary directly with energy consumption. Staff in the Generation Cost Modeling area considers Chemicals and Water as the only Other Production O&M costs that vary directly with energy output. These costs were classified as 100% energy related. The remaining cost items were split in groups based on the type of plant (i.e. Nuclear, Fossil, etc) and classified as capacity or energy related based on the plant stratification for that plant type.	2024 budget detail of Other Production O&M expenses and 2024 Plant Stratification Analysis.
Direct Assignment of Overhead Secondary Distribution Line Costs to the Lighting Class	In consultation with staff in the Company's Capital Asset Accounting area, identified specific lighting costs that are included in each FERC account code for distribution plant. Discovered that all lighting plant investment is included in FERC Account 373 except for the cost of wood poles that are solely used by lighting in overhead distribution areas. These costs are included in FERC account 364. This analysis quantified the amount of overhead distribution pole investment that is attributed to lighting only.	• TY2024 plant investment in FERC code 364 (overhead distribution poles). • The total number of overhead distribution poles based on 2024 data. • The number of street lights in overhead distribution area in 2024. • Estimated percent of distribution poles with lighting that only serve lighting load.
Customers Served by 3 Phase Vs 1 Phase Primary Distribution Lines	Customers who do not receive service off the single-phase primary distribution system should not pay the costs of this part of the distribution system. Based on data from the Company's GIS system determined the percent of customers in each class the receive service off the 3 phase or 1 phase distribution system.	2024 listing from the GIS system of all customer premises in MN and whether they receive service off the 3 phase or 1 phase distribution system.
Customers Served by Overhead Vs Underground Transformers	C&I secondary voltage customers with underground services own the service. This analysis determined the percent of customers that are served from an underground service. These customers are excluded from the allocation of distribution service costs.	2024 listing from the GIS system of all customer premises in MNCO and whether they are served from an overhead or underground transformer.