BC Hydro

Electric Distribution System
Cost of Service Study

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1. Executive Summary

This study was completed for BC Hydro to better understand the nature of costs of its electric distribution system. Distribution system costs are incurred to connect customers and to supply electricity to these customers. The purpose of this study is to review electric distribution system costs and provide a recommendation as to the appropriate classification (demand and customer related costs) of electric distribution system costs for use in a Cost of Service Study.

This study was also completed in response to the British Columbia Utilities Commission (BCUC) Directive #4 on page 88 of BCUC Order Number G-130-07: "BC Hydro is directed to conduct both a minimum system and zero intercept analysis for inclusion in its next FACOS or rate design filing". This study includes the use of the Minimum System, Zero Intercept and other methods to determine the classification of distribution costs. All of these methods have strengths and weaknesses and these issues are addressed in the report.

This study is completed on the basis of the embedded cost of the system, and costs are allocated to various sub-functions of the electric distribution system prior to classification of costs. This study is not done on the basis of incremental costs associated with first connecting the customer, and subsequent incremental costs to provide an increasing amount of capacity. Results from such incremental study will be different than the embedded cost study completed in this report.

Electric distribution systems are not designed to connect customers and supply electric energy simultaneously. Methods have been developed to classify electric distribution system costs as demand and customer related costs.

For the 2007 Rate Design Application (RDA) to the British Columbia Utilities Commission (BCUC), BC Hydro proposed classifying the distribution system as 75% demand related and 25% customer related (75%/25%). Interested parties questioned this proposal and requested that the BCUC direct BC Hydro to use a 55%/45% classification for the purpose of this RDA. The BCUC directed BC Hydro to use a classification of 65/35 for the 2007 RDA.

The results of this study show a range of results for classification of an electric distribution system. A variety of methods are used for the classification of costs for each function of the distribution system because each method has its own strengths. Based on a selection of methods assessed as most appropriate, a demand/customer classification of 75%/25% is appropriate.

2. BC Hydro Electric Distribution System

This study was also completed in response to the British Columbia Utilities Commission (BCUC) Directive #4 on page 88 of BCUC Order Number G-130-07: “BC Hydro is directed to conduct both a minimum system and zero intercept analysis for inclusion in its next FACOS or rate design filing”. This study includes the Minimum System, Zero Intercept and other methods as appropriate used to determine the classification of distribution costs.

This report includes a review of BC Hydro’s electric distribution system and the costs incurred in owning and operating the electric distribution system. The review of the system includes study of how costs are incurred in the planning, design and construction of the electric distribution system.

BC Hydro’s service area covers approximately 94% of British Columbia and the remainder of BC is served by FortisBC as shown in the map of BC Hydro’s service area in Appendix A. While the service area is large, the majority of the load in BC is located in the lower mainland. BC Hydro’s electric distribution system is predominately interconnected to the provincial electric transmission system and this distribution system is referred to as the integrated area (IA). The integrated area is connected to all of the larger generators in BC and is also interconnected to Alberta and Washington State. Communities that are remote to the electric transmission grid may have local generation, and these areas are referred to as the non integrated areas (NIA). The IA distribution system is large in comparison to the NIA, and both will simply be referred to as the distribution system.

2.1. General Description

The electrical transmission system in BC comprises of approximately 18,000 kM of lines that are energized at 69 kV and above. This transmission system transports electric energy from generation projects to the load. Some large loads are connected directly to the transmission system and most of the electricity moves from the transmission system to the distribution system before being distributed to the end use customers. A map of the high voltage transmission system in BC is shown in Appendix B. The electric transmission system includes substations that interconnect generators, provide switching capability and step down substations to reduce voltage to distribution levels. The transmission system includes approximately 300 transmission switching and substations, including 234 substations that are source substations for the distribution system. A source substation will have at least one distribution feeder, and on average, each distribution source substation has 6.3 distribution feeders.

BCTC manages the transmission system in BC which includes the step down substations. However, the costs associated with these step down substations are considered distribution costs in the BC Hydro Cost of Service Study. For the purpose of this study, the costs associated with Substation Distribution Asset (SDA) are considered part of the distribution system.

BC Hydro's electric distribution system contains approximately 57,080 kM of primary distribution circuits that are energized at a voltage less than 60 kV. The most common primary distribution voltages are 25 kV and 12.5 kV (3 phase L-L voltage where 1 phase L-N voltage is 14.4 and 7.2 kV respectively). The most common secondary voltage for single phase service is 120/240 V. Three phase secondary voltage that are commonly provided by BC Hydro include 120/208 V, 277/480 V and 347/600V.

The electric distribution system and its associated costs are dynamic in order to serve new load and address changes in load. The system changes over time as capital additions, rebuilds, reconfiguration and salvage of old facilities occur. This report is based on the electric distribution system as it existed at January 5, 2010. Forecast cost data for the fiscal year ending March 31, 2010 is used and is based the recent Revenue Requirements Application.

2.1.1 Configuration

There are 234 source substations that supply electricity into the electric distribution system. These source substations provide service to 1482 primary distribution feeders. On average, a source substation has 6.3 distribution feeders, with an average circuit length of 38.5 kM. Most primary distribution feeders are energized at 25 kV or 12.5 kV. Primary distribution voltages can be as high as 34.5 kV and as low as 4 kV.

The distribution system is normally a radially fed system, meaning there is only one line of supply. Distribution systems are normally designed with a series of switches, so that in the event of a fault, the fault can be isolated by opening switches, and some of the load may be restored by closing other switches. Trunk lines have switching capability that allow for faster restoration of service than branches.

The primary distribution feeders generally consist of three components: feeders, trunks and branches.

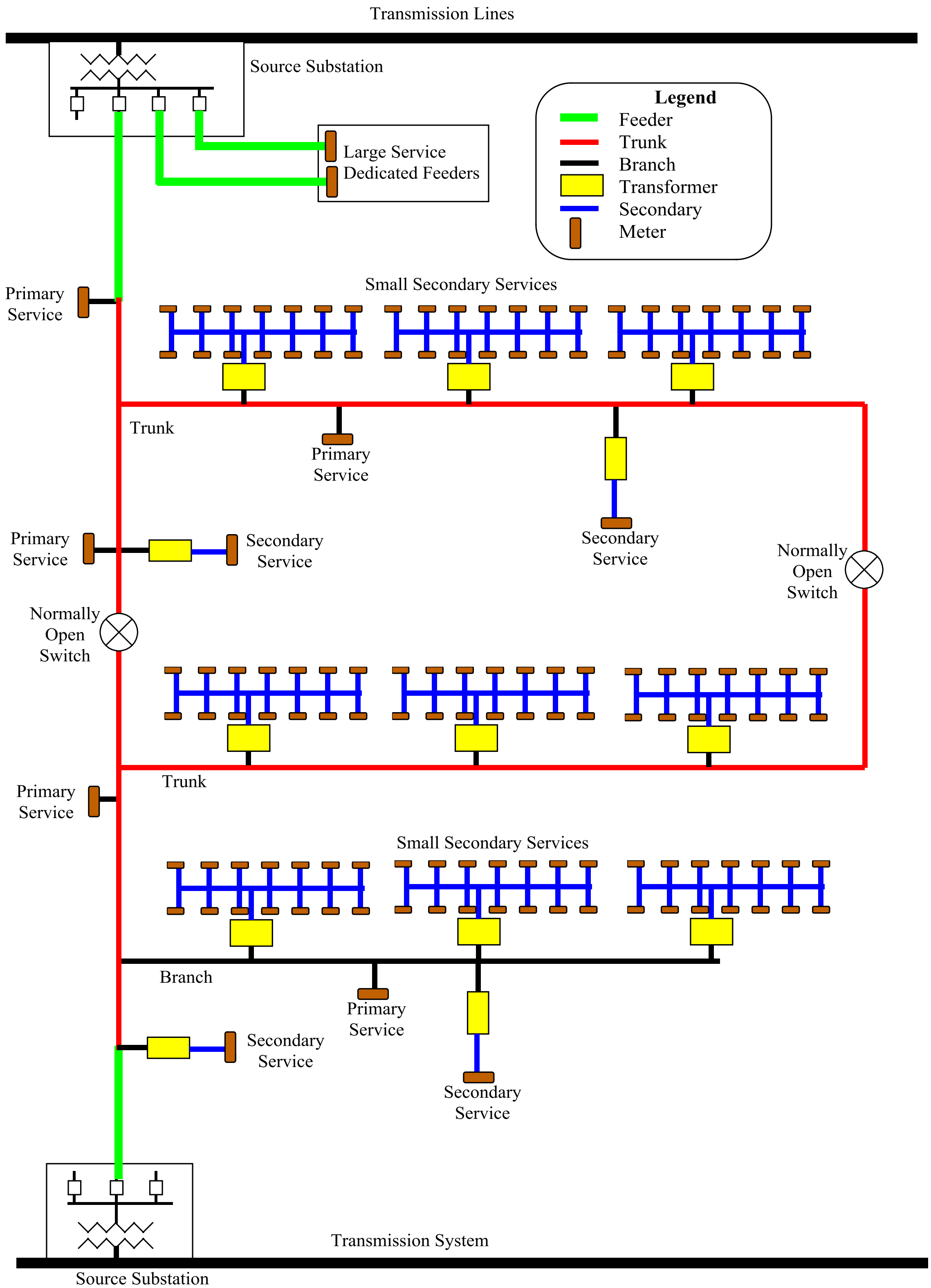
The feeders are defined as the cable or conductor that starts at the circuit breaker in the step down substation and ends at the first customer, or first protective device on the primary distribution feeder. Feeders are commonly underground cables of 500 or 750 mcm cable and when feeders are overhead conductor, the minimum size is normally 266 kcmil. All feeders are 3 phase circuits and can provide service to all customers.

The trunk lines are connected to the feeders. The trunk lines are sections of the primary distribution circuit that can be switched, or fed from one of two different sources. Trunk lines generally have lighter cables than feeders and include underground cable of 4/0 to 500 mcm and overhead conductor of 266 to 336 kcmil. All trunks are 3 phase circuits and can provide service to all customers.

The branches are fed from the trunk lines. The branch lines have no switching capability. In the event of a fault, all loads downstream of the fault will experience an outage until the fault is repaired. Branch lines have the smallest conductor and will include underground cable of #1 or larger and overhead cable of #2 or 1/0. Branches include both 3 phase and 1 phase lines.

Figure 1 as follows illustrates a typical distribution system layout. The BC Hydro electric distribution system starts at one source substation, goes through a feeder, a trunk, a normally open switch, another trunk and feeder and ends at a different source substation. In cases where this is not practical to end at a different source substation, the primary feeder may go through a normally open switch and then back to the same source substation. This configuration allows for faster restoration of service in the event of a distribution fault, but does not provide for restoration of service in the case of an outage to the source substation.

Figure 1 Example BC Hydro Distribution System Layout



Larger customers may take electric service directly from the primary distribution system and these customers are known as primary service customers. These customers own operate and maintain their transformers that transform voltage from primary voltage down to the voltage used by the customers equipment. These customers may have a meter on primary side of the transformer (primary metering), or may have a meter on the secondary side of the transformer (secondary metering) and the meter is owned by BC Hydro. Metering at lower voltage (secondary metering) is less expensive than primary metering.

The next component of the electric distribution system is the transformer. Transformers serve the function of converting the primary voltage (25 or 12.5 kV) down to a secondary voltage of less than 1000 volts for safe and easy use. BC Hydro provides transformation for all other distribution connected customers that have a load of 1500 kVA or less.

Transformers connected to overhead systems are generally pole mounted with the exception of large transformers, which are placed on a concrete pad on the ground. Transformers connected to underground systems are also placed on a concrete pad (pad mount), or for large services, the transformer may be placed in a vault or an electrical room supplied by the customer.

Secondary cables run from the transformer to the customer's service entrance. Secondary cables are relatively heavy cables for the amount of load that they carry because the amperage is high at secondary voltage. The meter is normally located at the customer's service entrance, and the customer is responsible for electrical wiring beyond the meter.

2.1.2 Distribution System Statistics

The electric distribution system has 57,080 kM of primary distribution line. 84% of this line (48,040 kM) is overhead and the remaining 16% (9,040 kM) is underground line. Of the overhead line, 65% is 1 phase line, 1% is 2 phase and the remaining 34% is 3 phase line. Of the underground line, 51% of this line is 1 phase while the remaining 49% is 3 phase.

The distribution step down transformers include 240,600 overhead transformers, 53,970 pad mount transformers and 326 vault transformers. A variety of transformers sizes have been used over the years and standardization of sizes has reduced the number of different sizes of transformers commonly used to about 8 different pole mounted transformer sizes and 8 different pad mount transformer sizes. BC Hydro provides other sizes where standardized sizes do not meet the customers' needs, up to 1500 kVA. Customers with loads larger than 1500 kVA are required to provide their own transformers, and BC Hydro does not carry any spare transformers for these large loads.

BC Hydro provides secondary cables or conductors between the transformer and the meter.

The distribution system also includes meters for each service (with the exception of small unmetered services and street lights). The smallest electric meters commonly used are the single phase 120/240 V, 200 amp meters that are used for small residential and commercial loads (maximum of 48 kVA). These maters can be replaced (meter socket is in place) for $47. The next size of most commonly used meter is the 3 phase meter for up to 600 V, 200 amp (maximum load of 208 kVA) and this meter can be replace for $890. Loads with voltage higher than 600 V require PT's to reduce voltage, or in excess of 200 amps require CT's to reduce the current in order to meter the load. The largest load served from a distribution feeder is up to 13,000 kVA, and primary metering (25 kV) is required for metering at the distribution voltage.

2.1.3 Cost Information

The costs in this study are based on the cost of owning and operating the BC Hydro electric distribution system for the fiscal year ending March 31, 2010 (F2010). These forecast costs are shown in the 2009/2010 Rate Design Application (RDA). The forecast cost of Field Operations (distribution) for F2010 is shown in Column 7 in the table below.

Table 1 Forecast Revenue Requirement of Electric Distribution System

Total Costs - Field Operations
($ million)

			F2007	F2008	F2009			F2010		
		Reference	Actual	Actual	RRA	Actual	Difference	RRA	Forecast	Difference
Line	Column		1	2	3	4	5 = 4 - 3	6	7	8 = 7 - 6
1	Domestic Energy Costs	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Current Operating Costs	Sched 5.0	114.7	132.9	144.4	143.2	(1.2)	165.6	165.6	0.0
3	Taxes	Sched 6.0	20.9	22.2	23.9	23.9	0.0	27.8	27.8	0.0
4	Current Amortization	Sched 7.0	86.8	93.3	103.1	103.7	0.6	114.3	113.6	(0.7)
5	Current Finance Charges	Sched 8.0	133.5	128.1	134.3	135.2	0.9	144.4	142.1	(2.3)
6	Return on Equity	Sched 9.0	118.0	102.9	103.6	106.1	2.5	133.0	129.9	(3.1)
7	Corporate Allocation	Sched 3.1	77.6	74.6	73.0	73.0	0.0	77.9	79.1	1.2
8	Non-Tariff Revenue	Sched 15.0	(1.9)	(2.0)	(2.0)	(4.3)	(2.3)	(2.0)	(2.0)	0.0
	Internal Allocations									
9	SDA Asset Charges	Sched 3.4	25.3	24.9	29.7	29.5	(0.2)	32.8	32.8	0.0
10	Total		574.8	576.9	610.0	610.3	0.3	693.9	689.0	(4.9)

The forecast cost of providing distribution service is $689 million for F2010.

2.1.4 Functionalization

The distribution system is broken down into several components for study in this report. In a Cost of Service study, the distribution system is generally considered one function of a vertically integrated electric utility (others being generation, transmission and customer care or retail). For this study, the distribution system is further functionalized (or sub functionalized) so that each of the components can be reviewed from the perspective of cost causation.

Some studies consider the distribution system as one integrated component, and this approach does not allow for a detailed review of cost causation. For example, a distribution pole may be considered one asset of the electric distribution system, and all poles are considered as having the same purpose. However, a distribution pole in a primary circuit has a different purpose than the pole that supports a secondary service, or a street light. Therefore, by considering each of the functions of the electric distribution system separately, a better insight is gained into costs of an electric distribution system.

The electric distribution system is functionalized in the following functions:
- Substation Distribution Asset (SDA)
- Primary,
- Transformers,
- Secondary,
- Meters.

The SDA function revenue requirement is shown in Table 1 above and is $32.8 million in F2010. The revenue requirement from the remaining functions is determined through a review of the distribution property accounts. Each account is reviewed to determine which function the assets belong in. The assets in one account may belong in more than one function, and in that case, the property in the account is allocated to the appropriate function. The functionalization of property is shown in Appendix 9. The net book value (original cost less accumulated depreciation) is used to determine the percentage of property associated with each function as follows:

Table 2 Functionalized Property

Summary	SDA*	Primary	Transformers	Secondary	Meters	Total
Total Net Book Value		2,070,098,641	732,585,599	289,507,285	113,831,279	3,206,022,804
		64.6%	22.9%	9.0%	3.6%	100.0%

The percentage of property in each function is used to allocate the remaining revenue requirement to each function. This allocation is based on the assumption that revenue requirement is proportional to net book value of electric distribution assets.

Table 3 Functionalized Revenue Requirement

Summary	SDA*	Primary	Transformers	Secondary	Meters	Total
Total Net Book Value		2,070,098,641	732,585,599	289,507,285	113,831,279	3,206,022,804
Tot Rev Req	32,800,000	423,673,608	149,933,524	59,251,571	23,297,107	688,955,810

2.1.5 Distribution Losses

Electric energy is lost from the distribution system. As electricity flows through lines, conductor heating occurs, and when transformers are energized, hysteresis losses occur in the transformer core, all of which contributes to the loss of electric energy. In 2010, 57,898[1] GWh of electric energy was injected into the electric distribution system and 52,622[2] GWh was delivered to consumers. The difference of 5,276 GWh is lost in the transmission and distribution system. The cost of electric energy in F10 is forecast at $23.3/MWh and the losses are estimated at $123 million. Approximately one half of these losses occur within the transmission system and the remainder in the distribution system.

The cost of lost energy in the distribution system is included in the cost of energy in the BC Hydro Cost of Service study, and therefore, the cost of losses in the distribution system is not considered part of distribution cost in this report. While the cost of lost energy is not considered a distribution cost within this report, the cost of distribution line loss is a material cost and distribution losses are a function of distribution design (distribution losses can be reduced by increasing capital costs of conductors and transformers).

2.1.6 Rate Design

This study includes the review of electric distribution costs and classification of these costs as demand and customer related. Rate design is influenced by several factors including but not limited to costs. Therefore, rate design may vary from a direct view of costs to achieve other objectives. For example, if energy conservation is a strong objective, the fixed costs associated with a distribution system may be recovered on the basis of an energy charge in order to provide a price signal to conserve energy. Also, if revenue stability were a high priority for a utility, rates may be designed to vary from the cost structure such that costs are recovered primarily on the basis of fixed monthly charges rather than on the basis of demand or energy.

[1] RRA - F10 Forecast Total Sources of Supply, Schedule 4.0
[2] RRA - F10 Total Domestic Energy Sales, Schedule 14

3. Distribution System Cost of Service Methods

An embedded cost of service study for a vertically integrated electric utility company includes three steps; functionalization, classification and allocation. Functionalization results in the categorization of costs as generation, transmission, distribution and customer care. Classification includes the categorization of costs as demand, energy or customer related. Classification of demand related costs also includes a study of the nature of the demand with respect to cost causation (coincident peak, non coincident peak, etc). The last step in the process is the allocation of costs to each of the rate classes on the basis of each rate classes' contribution to the total demand, energy consumption, and number of customers.

In this report, the focus is the distribution system, one of the functions of a vertically integrated utility. This study takes the same approach as a cost of service study in that the distribution system will be broken down into components, or sub-functions. These sub-functions (referred to as functions for the purpose of this report) include the SDA, primary distribution system, transformation, secondary, and meters. The second step of classification of costs as demand, energy and customer related and is the primary focus of this report. Classification of each of the distribution functions will be studied using methods that include the Zero Intercept and Minimum System studies. The last step in the study is the allocation of distribution costs to the various rate classes.

This study is based on the embedded cost of the distribution system as they occurred in the fiscal year F2010. In some cases, replacement costs will be used to apportion embedded costs. This study does not include the review of marginal costs or incremental costs of electric distribution systems.

The main focus of this report is to study the classification of the electric distribution system. Costs can be classified as demand, energy or customer related.

Costs that are variable and a function of energy production are classified as energy related costs. Electric distribution systems do not normally have costs that vary with energy production or delivery with the exception of losses. Capital costs associated with reducing losses may also be classified as energy related. There were no capital expenditures identified that could be associated with project to reduce energy losses on the distribution system, and therefore no distribution costs are classified as energy related.

Most distribution system costs are classified as either demand related or customer related. Demand related costs vary as demand on the distribution system increases, and customer related costs are proportional to the number of customers connected to the system. The following sections deal with methods to separate demand and customer related costs.

The classification of the electric distribution system occurs on the system as it exists, with systems grouped into similar groups. For example, in the study of the primary distribution system, the review considered overhead, underground and underground duct systems separately. A separate minimum system for each of the above systems was determined to maintain the existing functionality of the primary distribution system. Another approach would have been to consider the primary distribution system as one amorphous system, and that the minimum system would have been an overhead system (lowest cost). This latter approach would skew the results to have a heavier weighting on demand related costs.

The determination of the minimum system is a challenge because this is a hypothetical system, and the development of the minimum system has an impact on classification. The minimum standard system that is constructed by BC Hydro is used to develop the minimum system. One exception was used, and this occurred in the study of metering costs. The minimum system for metering is an unmetered service and this would be adequate for a system where each service notionally is required for 1 kWh per year. However, such minimum system lacks scalability, and therefore, the minimum system for metering was a single phase 120/240 V electric meter.

This study uses the concept of separating the distribution system into functions before applying the various methods of classifying the distribution property. Some studies consider the distribution system as one homogenous system, and apply various classification methods to all property within an account such as “poles”. In study of the electric distribution system, it becomes apparent that poles have different functions within a distribution system depending on where they are used. For example, a pole within the primary distribution system is used to deliver large amounts of power to a large number of customers whereas a pole carrying a service conductor is dedicated to the service of one customer. Intuitively, the pole in the primary distribution system has its primary purpose as being demand related, whereas the pole in the secondary system has its primary purpose as being customer related. Therefore, the distribution system was studied in functions, in order to more closely study the purpose of the electric distribution system for classification of the distribution system costs.

The concept of separating electric system costs into demand and customer costs is somewhat abstract because the system is built to supply both demand and customers, and one cannot be supplied without affecting the other. Therefore various methods may be used to separate demand and customer related costs, and judgment is required in the implementation of these studies. The National Association of Regulatory Utility Commissioners (NARUC) published a document titled Electric Utility Cost Allocation Manual in January 1992 that outlines methods for classifying and allocating distribution plant. Information technology systems have improved since that time, and these improvements have facilitated the ability to assign costs in addition to allocation methods. The following sections provide a brief description of some of the methods used for classifying distribution costs.

3.1. Zero Intercept Method

The zero intercept method is one of two methods identified by NARUC in the Electric Utility Cost Allocation Manual. The foundation behind the zero intercept method is that distribution system components each have a rated capacity and an associated cost. Larger equipment has a higher rating and also a higher cost.

The Electric Utility Cost Allocation Manual describes this method as follows:[3]

> The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate the installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component.

The following is a simple example of the application of the zero intercept method. This example uses transformers, and the same method is also applied to other functions of the electric distribution system. This example uses four transformers, the first two transformers have a capacity of 10 kVA and cost $2,300 each to install while the second set of two transformers have a capacity of 50 kVA and cost $3,700 each to install.

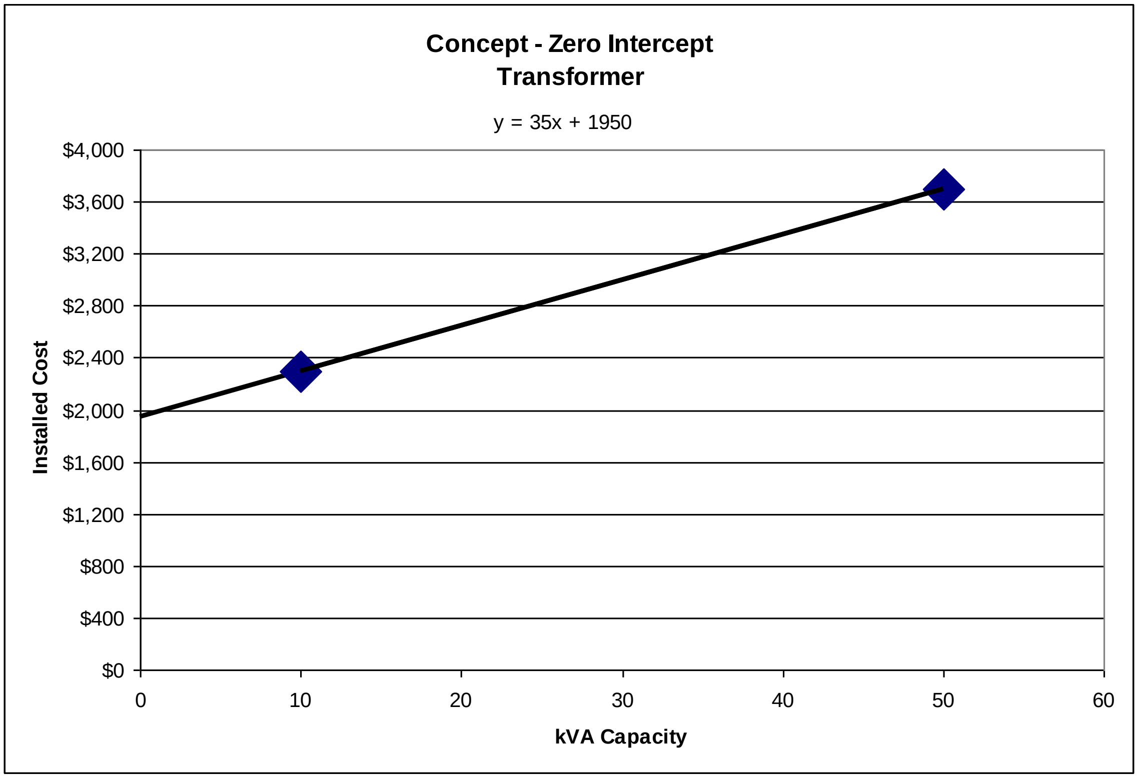
Table 4 Conceptual Application of Zero Intercept Method (A)

kVA	Units	Installed Cost	Total
10	2	$2,300	$4,600
50	2	$3,700	$7,400
Total			$12,000
Zero Intercept (Customer Related - $/Unit)			$1,950
Slope (Demand Related - $/kVA)			$35

This data is shown graphically as follows:

[3] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, P 92.

Figure 2 Zero Intercept Method – Linear Regression



The zero intercept (customer related component) and slope (demand related component are determine through linear regression as shown on the chart above, and the components are determined mathematically as shown below.

Table 5 Conceptual Application of Zero Intercept Method (B)

Customer Related Cost			
kVA	**Units**	**Zero Intercept** (per Unit)	**Total**
10	2	$1,950	$3,900
50	2	$1,950	$3,900
Customer Related Cost			$7,800
Customer Cost/Total Cost			65%

Demand Related Costs			
kVA	**Units**	**Demand Cost** ($/kVA)	**Total**
10	2	$35	$700
50	2	$35	$3,500
Total Demand Related Cost			$4,200
Demand Cost/Total Cost			35%

In the actual study, the linear regression analysis is completed with the physical inventory of distribution system components, and the cost of replacing these components. The linear regression analysis is completed with existing standards and does not include non standard equipment that is no longer used for construction of the electric distribution system.

The strengths of the zero intercept method include:

- Use of cost data representing equipment of various sizes
- Method is easy to understand,
- Is relatively independent of design standards employed by the utility company,
- Is appropriate for transformers where there is a strong correlation between capacity and cost.

The weaknesses of the zero intercept method include:

- Zero intercept costs are a function of voltage level and as such are not true costs with zero capacity,
- A reduced number of components could meet the customers demand when demand is low, but application of this method does not reduce system components for zero demand.
- Cost distortions may arise from economies of scale of certain sizes of equipment,
- Cost fluctuations may result in statistically unreliable results.

3.2. Minimum System Method

The minimum system method is described as follows in the Electric Utility Cost Allocation Manual as follows:

> Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method.

In simple terms, the smallest size interconnection that would be installed for the customer is considered a customer related cost and any incremental costs for the actual size interconnection is considered a demand related cost.

A simple example of the implementation of this method is shown in the following table using example costs consistent with earlier examples.

Table 6 Concept of Minimum System Method

Actual System			
kVA	**Units**	**Unit Cost**	**Total**
10	2	$2,300	$4,600
50	2	$3,700	$7,400
Total Cost			$12,000

Minimum System (Customer Related)			
kVA	**Units**	**Unit Cost**	**Total**
10	4	$2,300	$9,200
Total Customer Related Cost			$9,200
Customer Cost/Total Cost			77%

Incremental System (Demand Related)			
kVA	**Units**	**Unit Cost**	**Total**
Difference			$2,800
Total Demand Related Cost			$2,800
Demand Cost/Total Cost			23%

The minimum system method is dependent on the design standards in use by a utility. Utility companies will have a variety of minimum design standards that directly impact the customer related component. Utility companies have reduced the number of sizes of equipment in use in order to minimize costs. Invariably, utility company's most basic design provides for capacity that matches the load requirements for standard small services, which is larger than the nominal service of 1 kWh/yr.

The results of the minimum system method will be dependent on the current minimum standards, and the results of the minimum system method will be volatile when minimum system standard change. Also, minimum system standards may change as the result of other external factors that have no relation to the demand or customers that can be served from the distribution system. For example, if clearance requirements increase, longer poles are required, and the minimum system cost increases, resulting in a larger component of costs being customer related.

The minimum system method typically results in a higher portion of costs classified as customer related than the zero intercept method because the minimum system method does not extrapolate costs beyond the smallest standard system. This characteristic has resulted in some cost analysts introducing a load carrying compensation factor that attempts to offset this customer related cost. This compensation factor, commonly referred to as a Peak Load Carrying Capability (PLCC) adjustment factor was developed because the minimum system method has the ability to carry load. The PLCC is an attempt to reduce the customer related cost that result from the application of the minimum system method as outlined by NARUC. Another approach to address this issue would be to change the definition of a minimum system to design a hypothetical system that does not have the ability to carry demand. The challenge with this alternative approach is that the precise load must be defined (i.e. 1.0 kWh/yr), and the minimum system becomes a function of this load. The PLCC also shares this same challenge in that the load carrying capability must be determined, and each component of the minimum system has a different load carrying capability. Therefore the quantum of the PLCC adjustment factor becomes contentious.

The approach in this study is to use the minimum system method without further adjustments, recognizing that the application of the method may result in a bias towards customer related costs, depending on the construct of the minimum system.

The strengths of the minimum system method include:

- All of the fixed costs associated with the smallest electric service are considered customer related costs,
- Easy to understand,
- Is appropriate for customer dedicated facilities such as secondary service cables.

The weaknesses of the minimum system method include:

- Different minimum size standards produce volatile results for customer related costs,
- Various standards over time produce volatile results for customer related costs,

- Uses an incremental approach where customer connection is built first with ability to provide capacity coming in second, which tends to put extra weight on customer related costs.
- The minimum size system has inherent capacity (and scalability) associated with it. One could adjust the minimum size standard to compensate, or further compensation factors such as reduction for load carrying capacity may be used to try to minimize this effect,
- The current standards for higher distribution voltages result in additional capacity for minimal systems.

3.3. Direct Assignment of Classification

A simplification may be employed where the primary distribution feeders are considered demand related, and where all of the service connections including transformers, secondary conductors and meters are considered customer related. This simplification is based on the premise that all of the service connections are constructed to connect a customer to the system, and that primary distribution feeders are constructed only where there is sufficient load to warrant the extension of a primary distribution line.

The strengths of the Customer Versus System method include:

- Easy to understand,
- Simplicity in that all fixed costs incurred to connect a new customer are considered customer related costs,
- Can be used as a test against other methods to check for reasonableness.

The weaknesses of the Customer versus System method include:

- Does not take into account that primary distribution feeders may be extended to connect a new customer,
- Does not take into account that service connections are sized to meet different sizes of load unless analysis is completed to weight customer costs by size.

3.4. Primary System – System Additions

The primary distribution system is built primarily to serve additional load. The minimum primary distribution system is a single phase 14.4 kV line with #2 conductor. This minimum system has a capacity of approximately 3,000 kVA (approximately 1200 average residential customers or 25 million customers assuming 1 kWh/yr). Since it is the addition of load (demand) that will result in the need for upgrading the primary distribution system, regardless of the number of customers connected, the primary distribution system is intuitively demand related. The minimum system and zero intercept tests do not reflect intuition that the system is primarily demand related. Therefore, the capital additions to the electric system were reviewed to develop the classification of the primary distribution system.

Distribution planning engineers were engaged in discussions to determine from their experience, whether the primary distribution system is built to provide demand, or to connect customers. Distribution engineers classify most distribution expansion projects as either BC Hydro initiated to upgrade capacity to maintain reliability, or customer initiated to connect new customers. Approximately 37% of total capital additions are customer initiated.

A review of the existing system indicates that approximately 35% of distribution property is comprised of all functions except the primary electric distribution system. The customer initiated capital additions will first be spent on customer related facilities such as transformers and secondary systems. If new plant is being added in the same proportion as the existing system, then the first 35% of capital additions will be spent on customer interconnections, and the remaining 2% will be spent to expand the primary distribution system.

Therefore, 2% of customer initiated projects are assumed as primary distribution system related. For this view, the primary distribution system is classified as 98% demand related, and 2% customer related.

3.5. Direct Assignment of Costs

With the advancements in computer technology, and proliferation of databases that track distribution assets, a new method of completing a distribution cost of service is becoming viable. Electric utility companies are tracking assets with computer technology that was not practical ten to twenty years ago.

It is becoming more practical to assign distribution property and costs directly to various rate classes for meters, secondary service and transformation. However, the primary distribution system is shared, and judgment is required to allocate this property to rate classes. The primary distribution system is the largest function within distribution and therefore a significant part of the overall distribution system can not be assigned directly to rate classes.

Distribution companies typically have computer models of the system to allow modeling for operational purposes. These models may include detailed information on conductors including length and conductor type for each section of line from the substation to the last customer in the electric distribution system. Computers may be used to determine the facilities that are dedicated to one customer (the part of the system closest to the customer) and assign these facilities to the customer or rate class to which the customer belongs. As you move further into the distribution system, components are shared, and these facilities can be allocated to each customer on the basis of each customers load, and each customers' portion of shared facilities can be assigned to the customer or rate class to which the customer belongs. This process continues to the substation where essentially all of the facilities are shared and the sharing is on the basis of demand.

BC Hydro does not have systems in place to directly assign plant to individual customers, (and the rate class under which service is provided) at this time.

Such methods require maintenance of extensive databases to ensure accuracy. Practically, given the large number of components, it is very difficult to maintain an accurate database for such a system. While direct assignments are very precise, the accuracy is often difficult to verify because of the large number of components in a system and its associated database.

The strengths of the direct assignment method include:

- System is very precise in that each distribution system component is analyzed for use and assigned directly only to users of that component,
- A systematic approach that can be simply applied and requires very little judgment,
- Is appropriate for transformers, secondary and metering.

The weaknesses of the direct assignment method include:

- Requires maintenance of databases to ensure accuracy and alignment of database entries to actual equipment in the field,
- Distribution system databases may become useful for purposes for which they were not initially intended, and may become unwieldy in cost of service studies,
- The primary distribution system must still be allocated to rate classes.

The direct assignment of costs to rate classes eliminates the need to classify costs for the purpose of allocating costs across rate classes. Classifying costs may still be completed for use in design of a rate structure.

4. Distribution System Functions

This following section will consider each of the distribution functions, and outline the appropriateness of various methods for the classification of the distribution sub-function. The five distribution functions that will be reviewed include the SDA, primary system, transformers, secondary cables and meters.

Generally, the assets closest to the customer (meters, etc) are predominately classified as customer related because the amount of assets are proportional to the number of customers. The assets furthest from the customer (moving towards the transmission system) are predominately classified as demand related because the amount of assets are proportional to the load or demand put on the system.

4.1. Substation Distribution Asset (SDA)

The SDA is considered 100% demand related because these assets are designed and constructed to meet the total peak load in the area. The number of customers connected to the distribution system, down stream of the substation, has no impact on the sizing of the substation.

4.2. Primary Distribution System

As shown in Table 2, the primary distribution system accounts for 65% of the net book value of the electric distribution system assets.

The primary distribution system begins with a 3 phase primary distribution feeder at the transmission step down substation (at the low side circuit breaker). The first section of the distribution feeder, known as the primary distribution feeder is constructed with heavy cable (500 or 750 mcm) to ensure that the cable can withstand the peak demand of the entire load connected to the feeder. The next section of the distribution feeder is known as the trunk line, and it is also 3 phase and may constructed with conductor that is lighter than the primary feeder (cable is often referred to in the context of underground cable and conductor is often referred to in the context of overhead line). The trunk lines are constructed to meet the forecast peak demand on the trunk and typically use a 336 kcmil conductor. The last section of the primary distribution system is the branch lines, and this component is sized to meet the total peak demand on the branch. A branch may be extended to connect new customers. Branch lines will include 1, 2 and 3 phase lines, and will typically have lighter conductor than primary feeders or trunk lines and will have a minimum conductor size of #2 AWG.

The systems in place have the ability to consolidate line lengths by number of phases and by rural and urban, but do not have the ability to consolidate line length by feeder/trunk/branch.

Table 7 below shows the total circuit length of the primary distribution system.

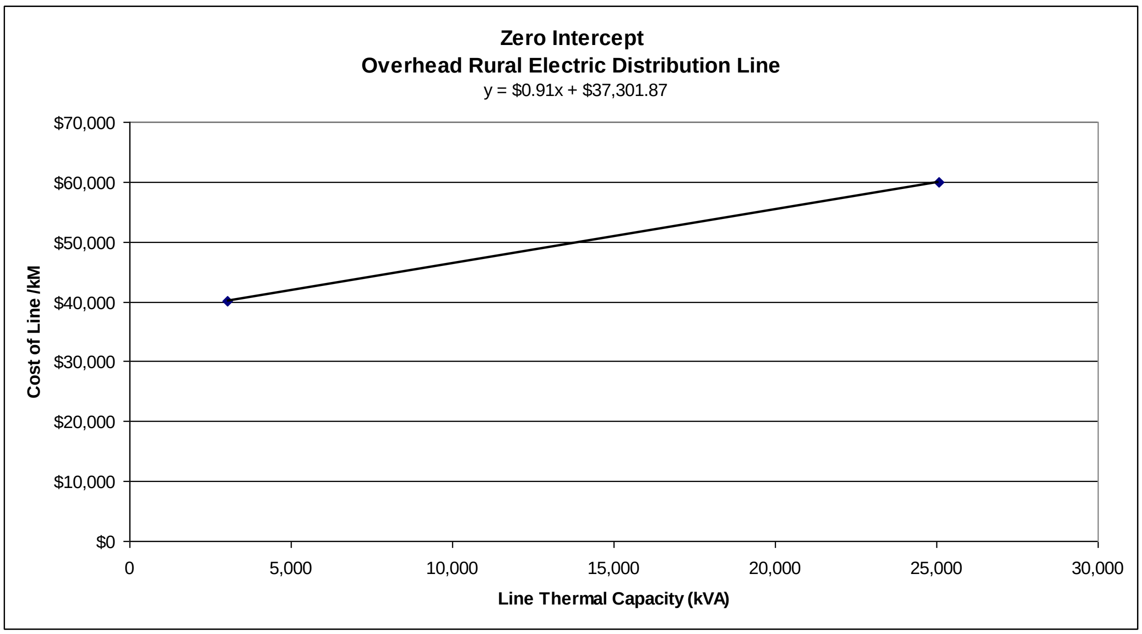
Table 7 Primary Distribution System Circuit Length (m)

	Rural OH 1 Ph	Rural OH 2 Ph	Rural OH 3 Ph	Urban OH 1 Ph	Urban OH 2 Ph	Urban OH 3 Ph	U/G 1 Ph	U/G 2 Ph	U/G 3 Ph	U/G 3 Ph Feeder
Meter	24,729,437	239,558	11,913,469	6,374,357	116,016	4,670,059	4,613,125	46,777	2,409,046	1,971,879

a) Zero Intercept Method

The zero intercept method uses linear regression with data for costs of lines with varying capacity. The capacity of a line is a function of the voltage on the line, the number of phases, and the conductor ampacity. There are various conductors, each having a different ampacity. The following chart shows the zero intercept of overhead one phase and three phase lines in rural areas.

Figure 3 Overhead Rural Electric Distribution System Zero Intercept



The following charts shows the zero intercept of overhead lines in urban areas.

Figure 4 Overhead Urban Electric Distribution System Zero Intercept

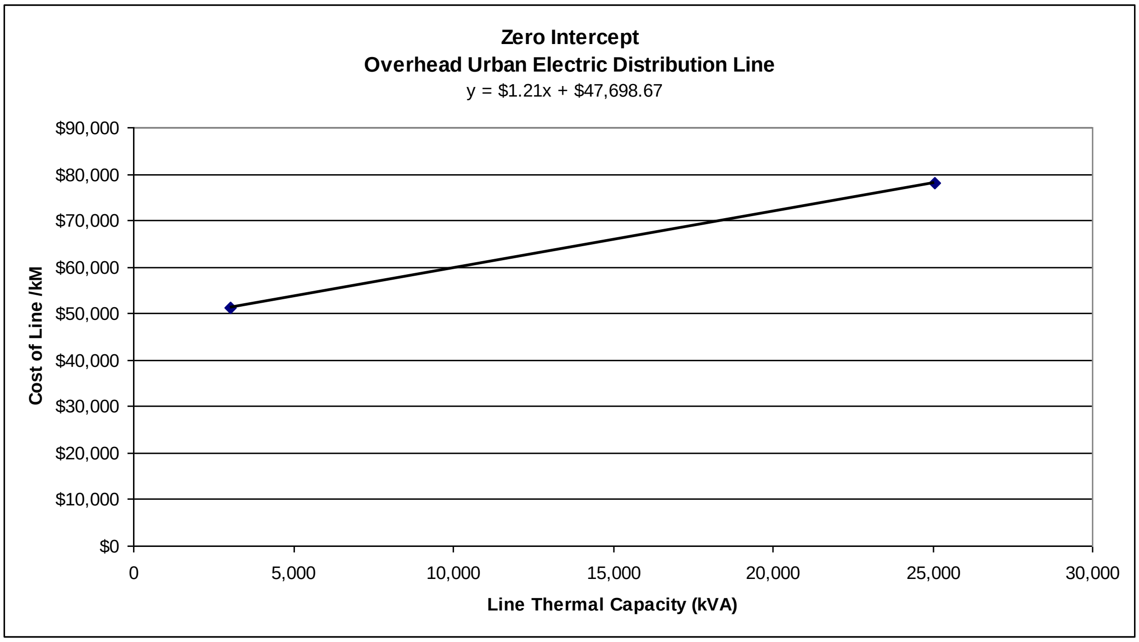
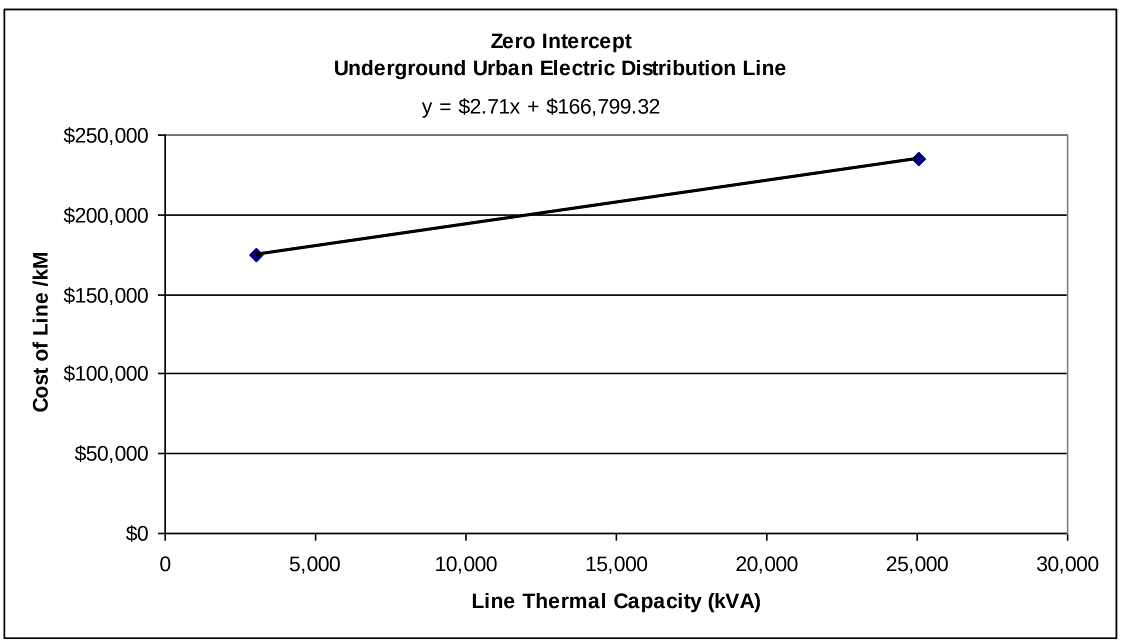


Figure 5 Underground Urban Electric Distribution System Zero Intercept



The calculation of the customer related costs of the primary distribution system on the basis of zero intercept is shown in the following table.

Table 8 Zero Intercept Analysis of Electric Distribution System

	OH Rural	OH Urban	UG Urban	Total
ZI Unit Cost	$37,302	$47,699	$166,799	
Length (m)	36,882,464	11,160,432	9,040,827	57,083,722
ZI Total Cost	$1,375,784,800	$532,337,721	$1,508,003,791	$3,416,126,312
Est RCN	$1,717,195,528	$699,326,141	$4,223,418,694	$6,639,940,364
Cust Related	80.1%	76.1%	35.7%	51.4%

The customer related component of costs, when determined using the zero intercept method varies widely from 80% for an overhead rural system to 36% for an underground urban system.

b) Minimum System Method

The minimum system analysis is completed on the basis that the minimum standard system is built to connect customers, and that all additional costs are incurred to serve increasing demand. The minimum system of the rural overhead electric distribution system is the single phase line with #2 AWG conductor costing approximately $40,000 per kM, and the analysis is summarized below.

Table 9 Rural Overhead Electric Distribution System – Minimum System

	Rural OH 1 Ph	Rural OH 2 Ph	Rural OH 3 Ph
Len (m)	24,729,437	239,558	11,913,469
RCN Cost (Cost $/kM)	$40,043	$50,028	$60,014
Est RCN	$990,239,590	$11,984,693	$714,971,245
Total RCN		$1,717,195,528	
Total Length (m)		36,882,464	
Min Sys Cost $/kM		$40,043	
Min Sys RCN		$1,476,882,656	
Min Sys Percent (Cust)		86.0%	

The minimum system summary for urban electric distribution systems is shown in the following tables.

Table 10 Urban Overhead Electric Distribution System – Minimum System

	Urban OH 1 Ph	Urban OH 2 Ph	Urban OH 3 Ph
Len (m)	6,374,357	116,016	4,670,059
RCN Cost (Cost $/kM)	$51,360	$64,698	$78,036
Est RCN	$327,387,398	$7,505,984	$364,432,759
Total RCN		$699,326,141	
Total Length (m)		11,160,432	
Min Sys Cost $/kM		$51,360	
Min Sys RCN		$573,200,550	
Min Sys Percent (Cust)		82.0%	

Table 11 Urban Underground Electric Distribution System – Minimum System

	U/G 1 Ph	U/G 2 Ph	U/G 3 Ph	U/G 3 Ph Feeder
Len (m)	4,613,125	46,777	2,409,046	1,971,879
RCN Cost (Cost $/kM)	$175,005	$204,895	$234,786	$1,440,709
Est RCN	$807,318,303	$9,584,343	$565,610,986	$2,840,905,061
Total RCN		$4,223,418,694		
Total Length (m)		9,040,827		
Min Sys Cost $/kM		$175,005		
Min Sys RCN		$1,582,186,734		
Min Sys Percent (Cust)		37.5%		

The addition of the analysis of treating these systems separately, and subsequently adding them together, is shown in the following table.

Table 12 Summary of Minimum System Analysis – By Electric Distribution System Type

	OH Rural	OH Urban	UG Urban	Total
Min Sys Unit Cost	$40,043	$51,360	$175,005	
Length (m)	36,882,464	11,160,432	9,040,827	57,083,722
Min Sys Cost	$1,476,882,656	$573,200,550	$1,582,186,734	$3,632,269,940
Est RCN	$1,717,195,528	$699,326,141	$4,223,418,694	$6,639,940,364
Cust Related	86.0%	82.0%	37.5%	54.7%

Another approach is the use of one minimum system across the entire electric distribution system and this approach is summarized in the table below.

Table 13 Summary of Minimum System Analysis – One Aggregate System

	OH Rural	OH Urban	UG Urban	Total
Min Sys Unit Cost	$40,043	$40,043	$40,043	
Length (m)	36,882,464	11,160,432	9,040,827	57,083,722
Min Sys Cost	$1,476,882,656	$446,896,606	$362,021,376	$2,285,800,639
Est RCN	$1,717,195,528	$699,326,141	$4,223,418,694	$6,639,940,364
Cust Related	86.0%	63.9%	8.6%	34.4%

The outcome of the minimum system analysis varies widely depending on how the approach is applied. For the purpose of this report, the separate study of overhead and underground, and rural and urban system has merit and is used. The minimum system approach application to one aggregate system is an oversimplification and is not appropriate.

c) Direct Assignment Classification Method

The primary electric distribution system is designed and constructed to meet the peak demand of the customers connected to the distribution feeder. This is similar in nature to the SDA which is also designed and constructed to meet the peak demand in the area. Since the primary distribution system is planned to meet the total peak demand, the classification of the primary system can be simplified to assume that the classification of this component is 100% demand related.

d) Primary System – System Additions

While the primary distribution system is designed and constructed to meet the peak demand, there are some instances where the primary system is extended to connect new customers. This would rarely occur, if ever, for the average customer, but may occur when larger customers are connected. An estimate of customer related expansion of the primary distribution system is completed through a review of capital additions to the electric distribution system. 37% of capital additions in the past year were customer related additions. Of the overall electric distribution system, 35.4 % consists of meters, secondary and transformer (from Table 2). Therefore, the additional 1.6% of capital additions associated with new customers must be used for extending the primary distribution system. On this basis, the primary distribution system is classified as 2% customer related and the remainder is classified as demand related.

4.3. Transformation

As shown in Table 2, transformation accounts for 23% of the net book value of the electric distribution system.

Transformers were grouped into three different types, overhead, pad mount and vault. Overhead transformers are mounted on poles or platforms above ground level and the primary lines feeding these transformers are normally overhead lines. Pad mounted transformers are set on a concrete pad on the ground and are normally fed from underground primary lines. Pad mounted transformers may also be fed through overhead lines with a riser near the pad mount transformer that converts the overhead line to an underground line. Vault transformers are enclosed in a concrete vault and these vaults are located underground, and are normally fed from underground primary distribution lines.

There are a total of 240,602 overhead or pole mounted transformers in service as summarized in the following table.

Table 14 Overhead Transformers in Service

Capacity (kVA)	1 Ph # sformer	Capacity (kVA)	2 Ph # sformer	Capacity (kVA)	3 Ph # sformer
3	4	3	2	9	12
5	858	5	46	15	153
7	11	7	2	21	3
10	37,266	10	577	30	5,807
15	3,245	15	65	45	754
20	3	20		60	
25	84,193	25	497	75	15,227
37	4,045	37	19	111	1,335
50	43,228	50	174	150	18,089
75	8,166	75	29	225	7,945
100	2,170	100	13	300	4,752
150	5	150		450	6
167	181	167	2	501	1,484
200	3	200		600	12
250	3	250	2	750	114
333	1	333		999	63
500		500		1500	36
	183,382		1,428		55,792

There are also 53,972 pad mounted transformers in service as shown in the following table plus 326 vault transformers.

Table 15 Pad Mount Transformers in Service

Pad Mount Transformers			
Transformer Capacity (kVA)	Total Count of Transformers	Count of 1 Phase Transformers	Count of 3 Phase Transformers
5	2	2	0
7	1	0	1
10	4	4	0
15	10	9	1
25	7,058	7,058	0
38	345	343	2
45	1	0	1
50	20,301	20,297	4
75	11,729	11,039	690
100	2,988	2,974	14
112	45	1	44
150	2,347	15	2,332
167	38	36	2
200	1	0	1
225	171	0	171
250	2	1	1
300	5,092	9	5,083
500	3,293	5	3,288
600	1	0	1
750	339	2	337
1,000	139	0	139
1,500	60	0	60
2,000	3	0	3
2,500	1	0	1
3,000	1	0	1
Total	53,972	41,795	12,177

a) Zero Intercept Method

The zero intercept method is used to develop the relationship between capacity and cost, and to extrapolate a zero intercept for each of the following transformer groups:

- Overhead 1 Phase
- Overhead 2 Phase
- Overhead 3 Phase
- Pad Mount 1 Phase
- Pad Mount 3 Phase
- Vault

The following charts are samples of the analysis of determining the zero intercept for the analysis of customer related costs of transformers.

Figure 6 Zero Intercept for Overhead 1 Phase Transformers

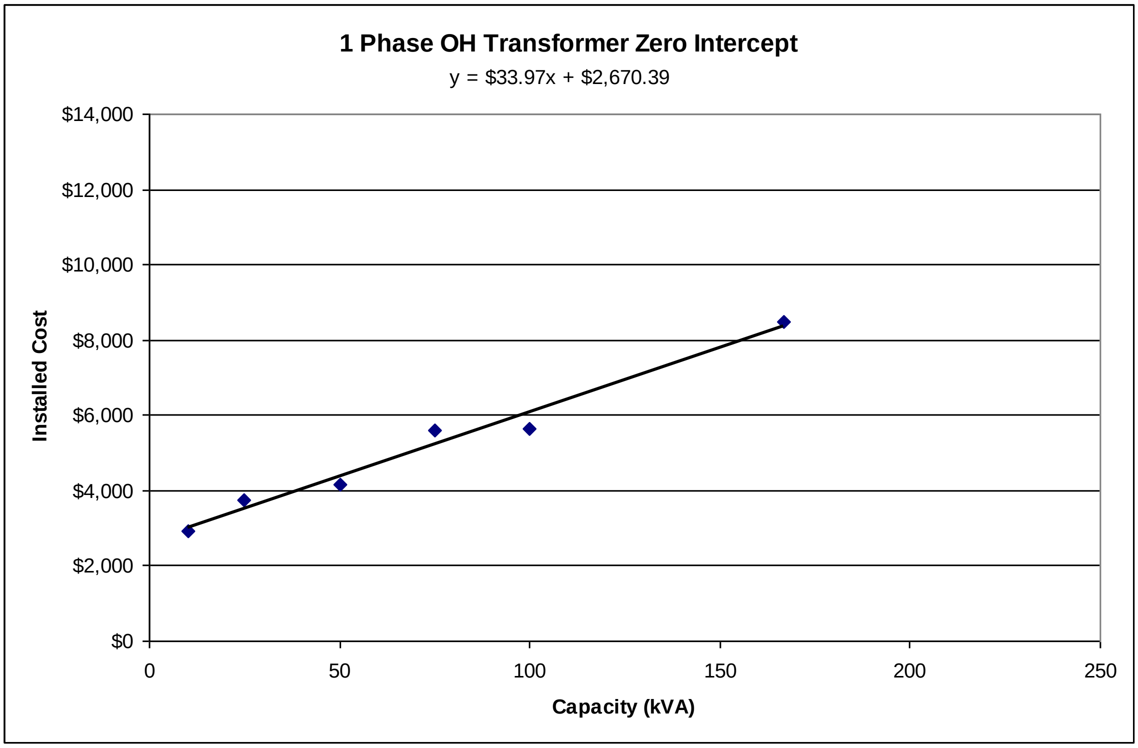


Figure 7 Zero Intercept for Overhead 3 Phase Transformers

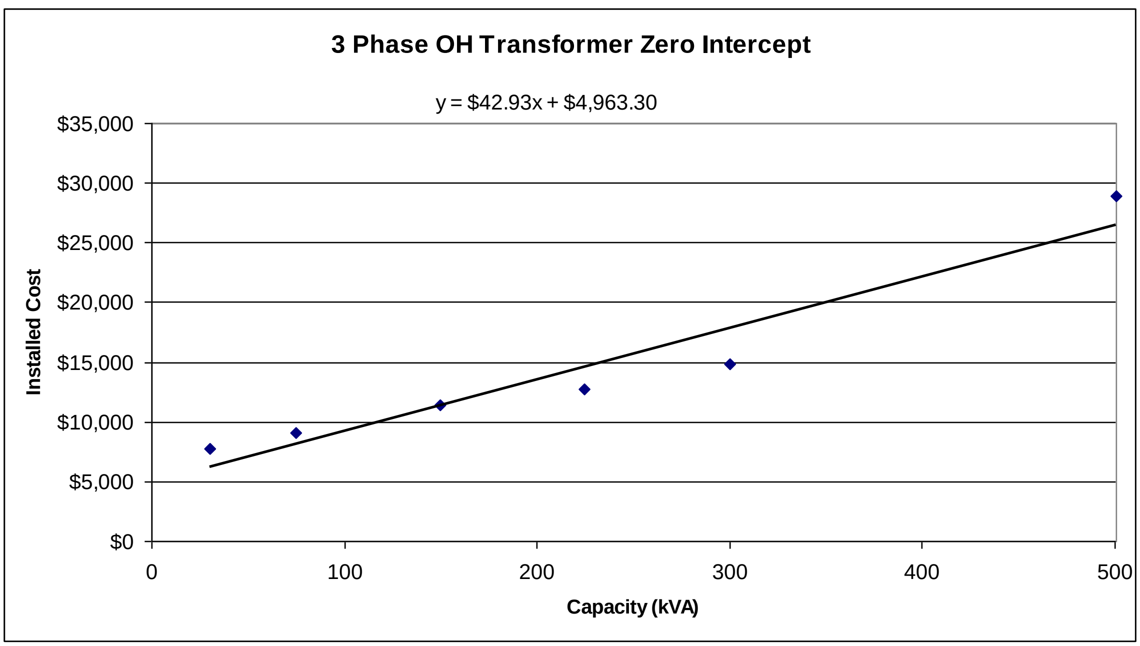


Table 16 Summary of Zero Intercept Analysis for Transformers – Segmented by Type

	1 Ph OH xformer	2 Ph OH xformer	3 Ph OH xformer	Sub Total Overhead
Zero Intercept Cost	$489,701,459	$5,450,448	$276,912,434	$772,064,340
Estimated RCN	$683,468,599	$8,146,907	$636,827,735	$1,328,443,241
% Customer	71.6%	66.9%	43.5%	58.1%

Figure 8 Zero Intercept for Pad Mount 1 Phase Transformers

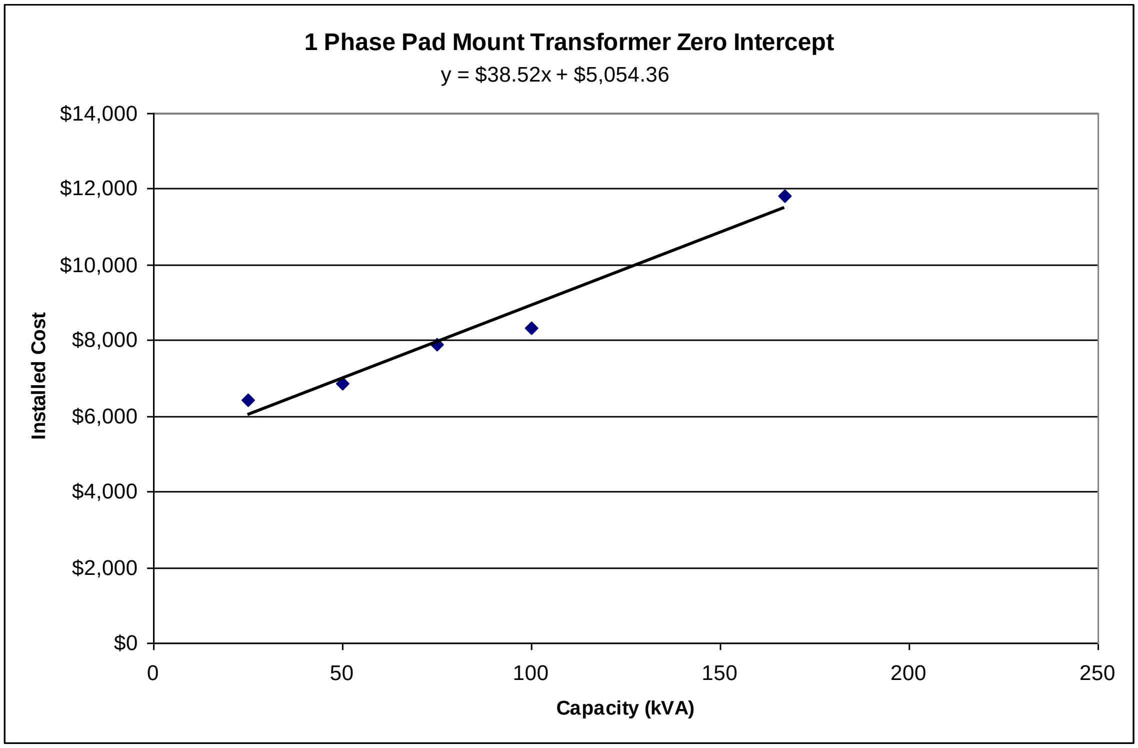


Figure 9 Zero Intercept for Pad Mount 3 Phase Transformers

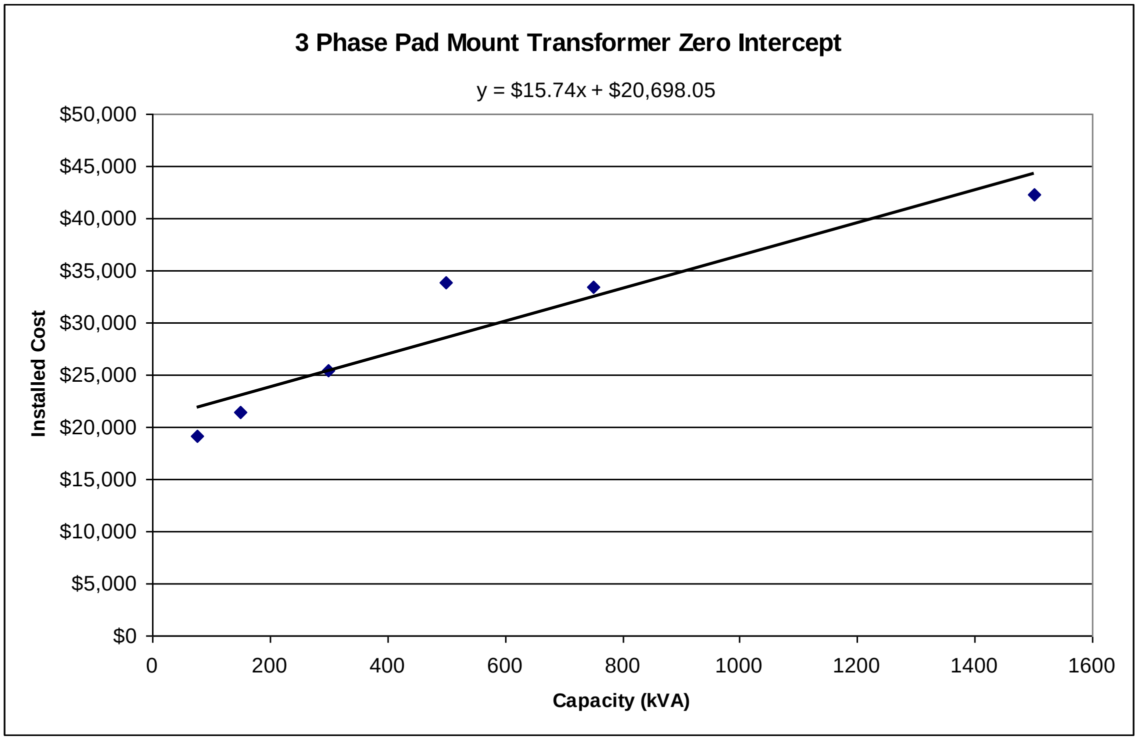


Table 17 Pad Mount and Underground Transformers Zero Intercept Method

Transformers	1 Ph LPT	3 Ph PMT	Vault	Sub Total UG
Zero Intercept Cost	$211,246,976	$252,040,155	$1,647,722	$464,934,853
Estimated RCN	$301,566,660	$316,738,529	$18,948,357	$637,253,547
% Customer	70.0%	79.6%	8.7%	73.0%

The results from Table 16 and Table 17 are added together, and the percent customer related cost for all transformers is 62.4% as shown below.

Table 18 Zero Intercept Method for Transformers

Transformers	Sub Total Overhead	Sub Total UG		Total Transformers
Zero Intercept Cost	$772,064,340	$464,934,853		$1,238,646,916
Estimated RCN	$1,328,443,241	$637,253,547		$1,984,645,145
% Customer	58.1%	73.0%		62.4%

The segmented approach above uses different zero intercepts based on the type or group of transformers. A simpler approach is to assume that the zero intercept is calculated on the basis of all transformers regardless of type. This simpler approach is not recommended, and is shown to illustrate that when using one method on all components, results will vary. On the basis of this assumption, the zero intercept analysis is completed as follows. As shown in the chart, the zero intercept is a combination of all transformers.

Figure 10 Zero Intercept for All Transformers – Aggregate System

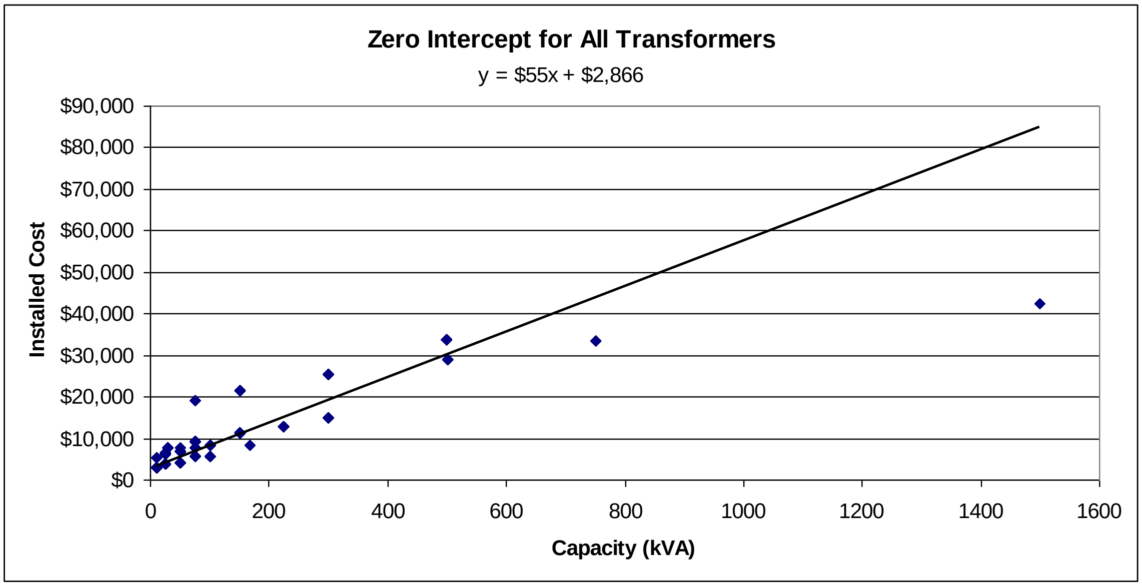


Table 19 Summary of Zero Intercept Analysis for Transformers – Aggregate System

Aggregate System	Total # of Trans	ZI Unit Cost	Total
Zero Intercept Cost	294,900	$2,866	$845,183,400
Estimated RCN			$1,984,645,145
% Customer			42.6%

b) Minimum System Method

The minimum system test was also applied to the transformers. As in the zero intercept calculations, the minimum system component was calculated for:

- Overhead 1 Phase
- Overhead 3 Phase
- Pad Mount 1 Phase
- Pad Mount 3 Phase
- Vault

The minimum system for transformers is the smallest transformer in a group. For example, the smallest transformer for 1 phase overhead transformers is a 10 kVA transformer and the cost of a 10 kVA transformer is used for all 1 phase overhead transformers. The smallest 3 phase overhead transformer is a 30 kVA transformer. The minimum system and RCN of overhead transformers is shown in Table 17.

Table 20 Customer Component of Overhead or Pole Mounted Transformers

	1 Ph OH xformer	2 Ph OH xformer	3 Ph OH xformer	Sub Total Overhead
Minimum System Cost	$537,483,473	$7,650,274	$434,269,306	$979,403,054
Estimated RCN	$683,468,599	$8,146,907	$636,827,735	$1,328,443,241
% Customer Related	78.6%	93.9%	68.2%	73.7%

The minimum system and RCN for pad mount transformers is shown in Table18. In comparison with Table 20, the customer related component is similar to that of overhead transformers.

Table 21 Customer Component of Pad Mount Transformers

	1 Ph LPT	3 Ph PMT	Sub Total Pad Mount
Minimum System Cost	$267,936,878	$233,799,374	$501,736,252
Estimated RCN	$301,566,660	$316,738,529	$618,305,190
% Customer Related	88.8%	73.8%	81.1%

The minimum system and RCN for vault transformers is shown in Table 19. As shown in this table, the customer related component is smaller than that of overhead or pad mount transformers and this occurs as a result of the large variation in size seen with vault transformers.

Table 22 Customer Component of Vault and All Transformers

	Vault	Total Transformers
Minimum System Cost	$2,089,901	$1,483,229,207
Estimated RCN	$18,948,357	$1,965,696,788
% Customer Related	11.0%	75.5%

As shown in the tables above, the configuration of the distribution system, and the sharing of transformers between customers has an impact on the portion of transformer costs that are considered customer related. A distribution network makes use of larger transformers that are shared by a larger group of customers, and this tends to reduce the customer related component (and conversely increases the demand related component) of transformer costs.

When the minimum system analysis is completed on transformers as an aggregate basis, the minimum system becomes the smallest standard overhead transformer, and the summary data is shown in the following table.

Table 23 Classification of Transformation on an Aggregate Basis.

Aggregate System	Total # of Trans	Min Cost	Total
Minimum System Cost	294,900	$2,931	$864,337,155
Estimated RCN			$1,965,696,788
% Customer Related			44.0%

c) Direct Assignment Classification Method

The transformers are designed and installed only when a new customer requests service. The simplified approach is to classify all of these costs as customer related costs.

Improvements in databases regarding transformers may allow for direct assignment of transformers to rate classes, eliminating the need to classify costs for the purpose of allocating the transformation costs to rate classes. Challenges remain where shared transformers provide service to more than one rate class.

4.4. Distribution Secondary

The distribution secondary includes the components of the distribution system that are connected to the low side of the distribution transformer and extend to the customers service entrance and meter. The voltage on the secondary system is 600 volts and below and the most common secondary cable is energized at 120/240 volt for residential and small commercial service.

The secondary system is at low voltage and has relatively high amperage. Therefore, even though the electrical load may be small, the cables tend to be thick.

BC Hydro tracks secondary service separately from secondary cable and the distinction is that secondary service may be shared by more than one service and secondary cable is dedicated to one service.

While various methods can be used to classify the secondary system as customer related and demand related, from a practical perspective, secondary cable and secondary service is primarily customer related. The secondary cable is installed to connect the customer and the cable is sized to meet the forecast peak demand of the customer. Secondary conductor and cable accounts for a small portion of the cost to install the equipment, and therefore the zero intercept method will indicate that the majority of costs associated with the secondary cable are customer related. Secondary conductor and cable is standardized to a large degree, and most installations are the basic minimum system, and therefore this method also indicates that the majority of secondary costs are customer related.

Standard secondary cable sizes have been developed based on experience. Experience shows that it is less expensive to provide cables slightly oversized than it is to provide cables slightly undersized which occasionally necessitates the removal and replacement of the undersized cables.

a) Zero Intercept Method

The zero intercept charts for overhead secondary cable, and overhead secondary service are shown in the following two charts. The summary zero intercept data follows in a table.

Figure 11 Zero Intercept of Overhead Secondary

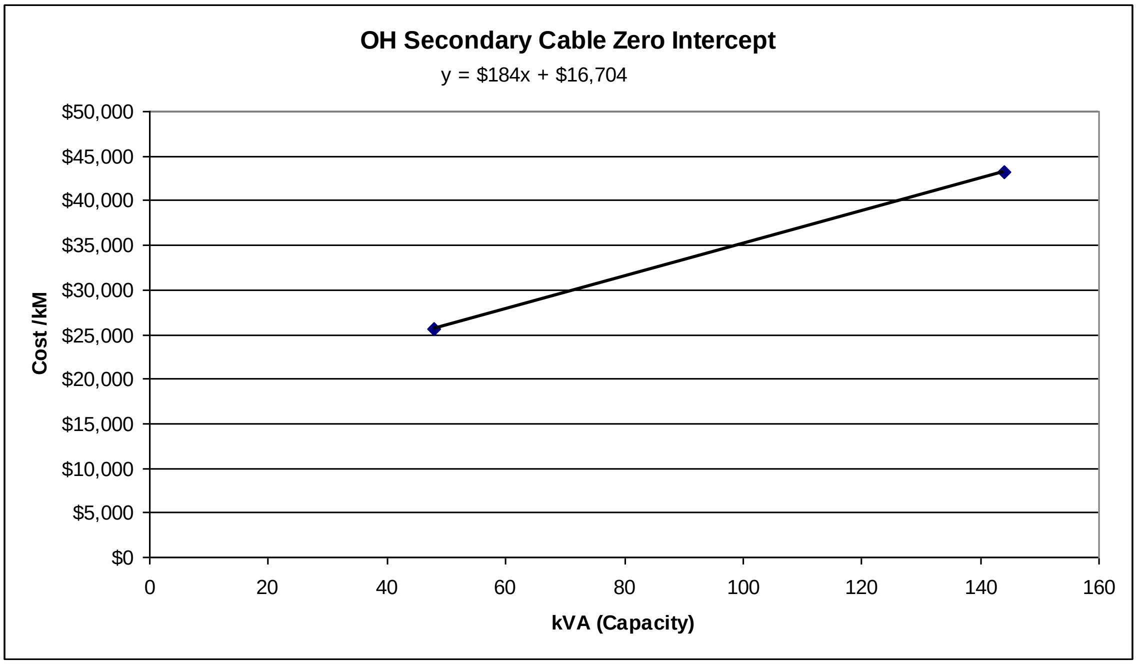


Figure 12 Zero Intercept of Overhead Service

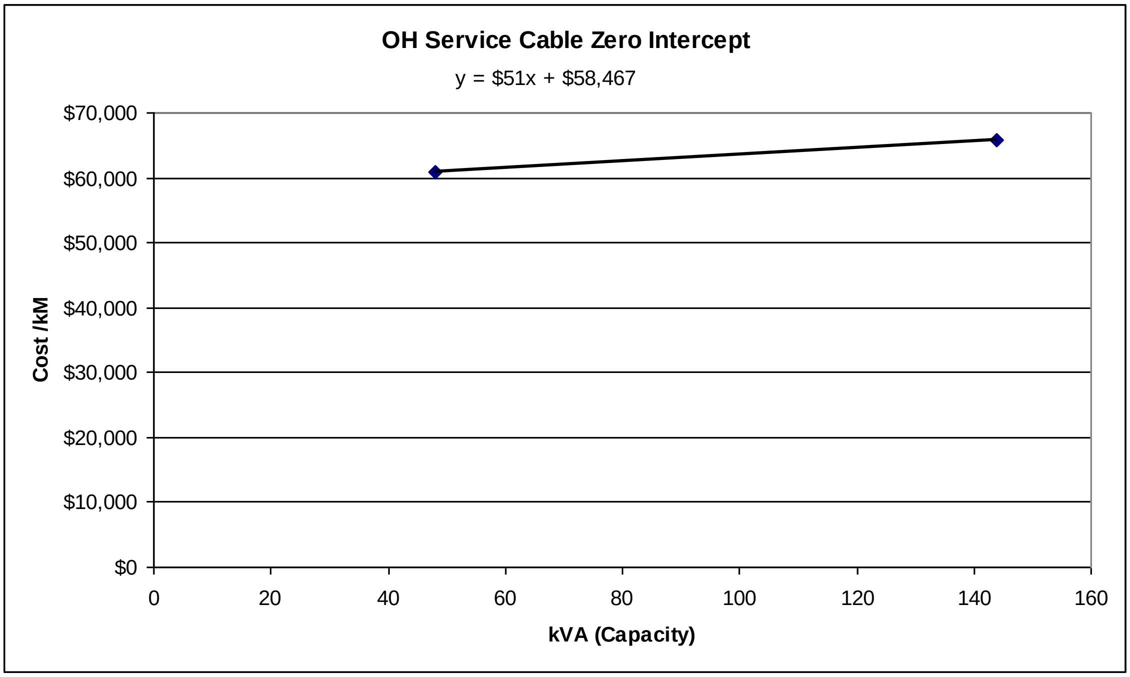


Table 24 Summary Zero Intercept Method of Secondary/Service

Secondary/Service	1 Ph OH Secondary	3 Ph OH Secondary	1 Ph OH Service	3 Ph OH Service	Sub Total Overhead
Zero Intercept Cost	$230,949,347	$7,855,402	$860,235,817	$24,555,324	$1,123,595,889
Estimated RCN	$353,325,672	$20,342,754	$896,203,399	$27,635,394	$1,297,507,219
% Customer	65.4%	38.6%	96.0%	88.9%	86.6%

Secondary/Service	1 Ph U/G Secondary	3 Ph U/G Secondary	1 Ph U/G Service	3 Ph U/G Service	Sub Total Underground
Zero Intercept Cost	$0	$0	$109,420,994	$17,880,445	$127,301,440
Estimated RCN	$179,547,119	$30,948,545	$145,549,737	$35,591,800	$391,637,200
% Customer	0.0%	0.0%	75.2%	50.2%	32.5%
Secondary/Service					**Total Sec/Service**
Zero Intercept Cost					$1,250,897,329
Estimated RCN					$1,689,144,420
% Customer					74.1%

b) Minimum System Method

Secondary cables and services are designed and built to established standards. The standard cable types and sizes are designed to connect the customer and ensure the cable can serve the peak demand associated with the service. The minimum system secondary and service cable is 200 amp.

Table 25 Minimum System Summary Secondary and Service Cable

Secondary/Service	1 Ph OH Secondary	3 Ph OH Secondary	1 Ph OH Service	3 Ph OH Service	Sub Total Overhead
Minimum System Cost	$353,325,672	$12,017,853	$896,203,399	$25,582,014	$1,287,128,938
Estimated RCN	$353,325,672	$20,342,754	$896,203,399	$27,635,394	$1,297,507,219
% Customer Related	100.0%	59.1%	100.0%	92.6%	99.2%
Secondary/Service	**1 Ph U/G Secondary**	**3 Ph U/G Secondary**	**1 Ph U/G Service**	**3 Ph U/G Service**	**Sub Total Underground**
Minimum System Cost	$179,547,119	$9,788,356	$145,549,737	$23,784,230	$358,669,442
Estimated RCN	$179,547,119	$30,948,545	$145,549,737	$35,591,800	$391,637,200
% Customer Related	100.0%	31.6%	100.0%	66.8%	91.6%
Secondary/Service					**Total Sec/Service**
Minimum System Cost					$1,645,798,380
Estimated RCN					$1,689,144,420
% Customer Related					97.4%

c) Direct Assignment Classification Method

The secondary cables and services are designed and installed only when a new customer requests service. The simplified approach is to classify all of these costs as customer related costs.

4.5. Metering

Most electric services in BC Hydro's service area have an electric meter to meter the energy consumption and demand for each service. Customers with small and predictable consumption, including lighting service may have an electric service without a meter, and in these cases, the invoice for service is based on the estimated consumption. Most electric services do include a meter. The most common meter is a single phase 120/240 Volt meter and this meter is used for most residential services. The standard 120/240 Volt meter has an ampacity of 200 amps and therefore can meter a load of up to 48 kVA. Three phase electric meters are more expensive than 1 phase meters and also have a large range for metered demand and energy. A typical 3 phase 480 volt meter with a capacity of 200 amps can meter a load from 0 to 230 kVA.

When a service has voltage in excess of 600 volts (primary service) potential transformers (PT) in a metering tank are required to transform the voltage down to a level that is practical to meter. When peak current is greater than 200 amp, a current transformer (CT) is used to lower the current to a lower level that is practical to meter. The cost of instrument PT's and CT's increases as voltage and current increase.

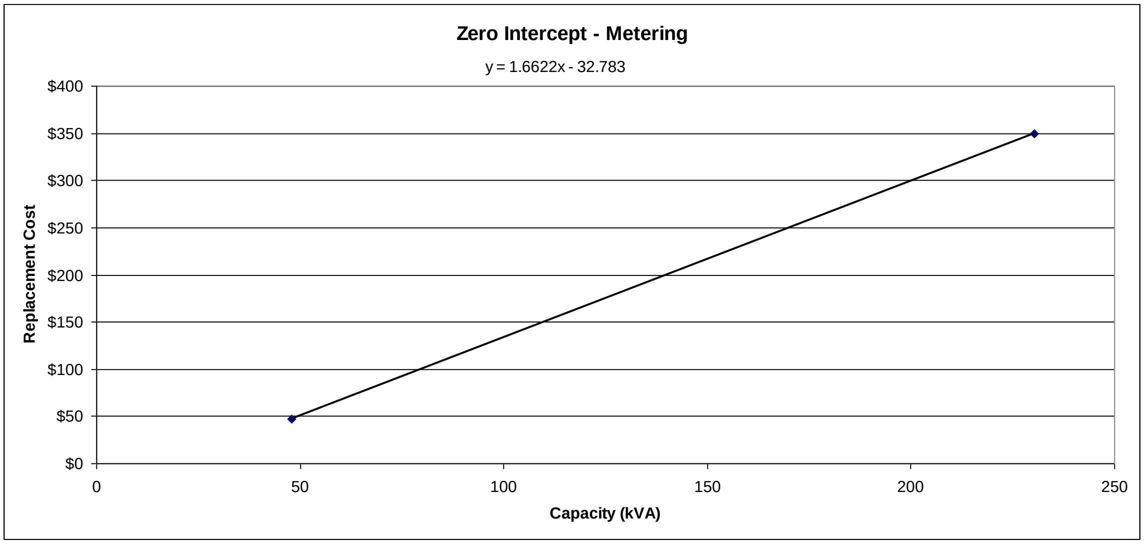
While metering costs are often considered customer related, the zero intercept and minimum system methods can be used to separate costs into customer and demand related.

a) Zero Intercept Method

The zero intercept method is applied to meter costs for distribution voltage services as shown in the following Figure. The zero intercept in this chart is slightly negative, which is not intuitive. One potential explanation is that the volume of standard 1 phase 200 amp meters is quite high and economies of scale drives down the cost of these meters, whereas the volume of 3 phase meters is not as high and the same economies of scale are not achieved. When a zero intercept is negative, it is set to zero to ensure that negative costs are not applied to the account of small services. A zero intercept indicates that customer related costs are zero and all costs are demand related costs.

The conclusion that metering costs are completely demand related is not readily intuitive since metering costs are typically considered customer related. As shown in this example, the methodology used can results in a range of results for the classification of distribution property.

Figure 13 Zero Intercept Cost of Metering



The negative zero intercept shown in this chart indicates that all metering costs are demand related according to the zero intercept method.

b) Minimum System Method

The minimum system method for electric metering is based on the smallest standard size for metering. Services with small and predictable load are not metered because the cost of metering exceeds the value provided. According to this definition, the minimum system for metering is zero, and all costs associated with metering are demand related costs (0% customer related portion)

If a different standard is chosen for the smallest standard meter – a 1 phase 120/240 volt meter, then the minimum system changes. In this case, a small meter is assumed to provide service to all metered services. The result of the minimum system method is shown in the following table.

Table 26 Minimum System Costs of Metering.

Electric Metering	Amount
Minimum System Cost	$82,568,160
Estimated RCN	$162,251,411
Customer Related Portion	50.9%

c) Direct Assignment Classification Method

The simplified approach is to classify all of the metering costs as customer related costs because the meters are installed only when a new customer requests service.

The inventory and usage of electric meters is monitored, and this data can be used to address the difficulty of classifying metering costs. The meter type (and associated cost) is tracked for each customer, and therefore metering costs can be directly assigned to each rate class. This eliminates the need to classify the cost in order to allocate metering costs on the basis of customer count or demand.

The direct assignment of metering costs to each rate class will be the most precise and accurate means of ensuring that the costs of meters are to the account of the correct rate class.

5. Compilation of BC Hydro System Results

The following table summarizes the results from the previous sections. This table shows the customer and related proportion of costs for each of the functions, and for each of the methods as well as the average of the methods. The results from the zero intercept method show transformer analysis completed by segments and on an aggregate basis, and this table shows the difference in results between the two.

Table 27 Summary of Customer and Demand Related Portion by Function

Total, Customer and Demand Related Portions of Revenue Requirement (F09 Actual Revenue Requirement)						
Summary	**SDA***	**Primary**	**Transformers**	**Secondary**	**Meters**	**Total**
Total Net Book Value		2,070,098,641	732,585,599	289,507,285	113,831,279	3,206,022,804
Tot Rev Req	32,800,000	423,673,608	149,933,524	59,251,571	23,297,107	688,955,810
Customer Related						
Zero Intercept (Segments)	0.0%	51.4%	62.4%	74.1%	0.0%	
Zero Intercept (Aggregate)	0.0%	51.4%	42.6%	74.1%	0.0%	
Min System	0.0%	54.7%	74.8%	97.4%	0.0%	
Direct Assignment	0.0%	0.0%	100.0%	100.0%	100.0%	
Cap Expenditure	N.A	1.6%	N.A	N.A	N.A	
Demand Related						
Zero Intercept (Segments)	100.0%	48.6%	37.6%	25.9%	100.0%	
Zero Intercept (Aggregate)	100.0%	48.6%	57.4%	25.9%	100.0%	
Min System	100.0%	45.3%	25.2%	2.6%	100.0%	
Direct Assignment	100.0%	100.0%	0.0%	0.0%	0.0%	
Cap Expenditure	N.A	98.4%	N.A	N.A	N.A	

The next step is the application of percentages to the revenue requirement, to develop the total revenue requirement by customer and demand related costs, for each method.

Table 28 Revenue Requirement by Function and by Customer and Demand Related Classification

Total, Customer and Demand Related Portions of Revenue Requirement (F09 Actual Revenue Requirement)							
Summary	**SDA***	**Primary**	**Transformers**	**Secondary**	**Meters**	**Total**	
Customer Related							
Zero Intercept (Segments)	0	217,972,223	93,575,770	43,878,801	0	355,426,794	52%
Zero Intercept (Aggregate)	0	217,972,223	63,850,873	43,878,801	0	325,701,897	47%
Min System	0	231,763,665	112,211,056	57,731,085	0	401,705,806	58%
Direct Assignment	0	0	149,933,524	59,251,571	23,297,107	232,482,201	34%
Cap Expenditure	N.A	6,647,674	N.A	N.A	N.A	N.A	
Appropriate Method	0	0	93,575,770	57,731,085	23,297,107	174,603,961	25%
Demand Related							
Zero Intercept (Segments)	32,800,000	205,701,385	56,357,754	15,372,770	23,297,107	333,529,016	48%
Zero Intercept (Aggregate)	32,800,000	205,701,385	86,082,651	15,372,770	23,297,107	363,253,913	53%
Min System	32,800,000	191,909,944	37,722,468	1,520,486	23,297,107	287,250,004	42%
Direct Assignment	32,800,000	423,673,608	0	0	0	456,473,608	66%
Cap Expenditure	N.A	417,025,935	N.A	N.A	N.A	N.A	
Appropriate Method	32,800,000	423,673,608	56,357,754	1,520,486	0	514,351,849	75%
Note: SDA is considered demand related.							

Table 28 shows the results of each of the methods of classifying the distribution revenue requirement. The advantages and disadvantages of each method are outlined in the analysis above. There is no one method that is always superior to other methods, and judgment, and understanding of the planning, design and operation of the electric distribution system is required to assess the best method for classifying costs. The shaded blocks show the method that is assessed as the best method for each function. On the basis of how the electric distribution system is planned, designed and operated, a variety of methods were used for the various functions and this is shown as the "Appropriate Method" in Tables 27 and 28.

Table 29 Summary of Classification Results

Classification Method	Demand	Customer
Zero Intercept (Segments)	48%	52%
Zero Intercept (Aggregate)	53%	47%
Min System	42%	58%
Direct Assignment	66%	34%
Appropriate Method	75%	25%

The best methods for classifying each function are as follows:

SDA – The SDA is an extension of the transmission system that is classified as all demand related. These assets are constructed to meet the total forecast load served from the substation and the cost of owning and operating these assets is not related to the number of customers served.

Primary Distribution System – Based on discussions with distribution planning engineers, the primary distribution system is planned and sized to meet the total forecast load served from the feeder. Feeders are designed in standard sizes, and with increased load, additional feeders are used. The review of capital expenditures provides results that are consistent with the planners view of primary distribution system costs. The zero intercept and minimum system results do not reflect the views of distribution system planners.

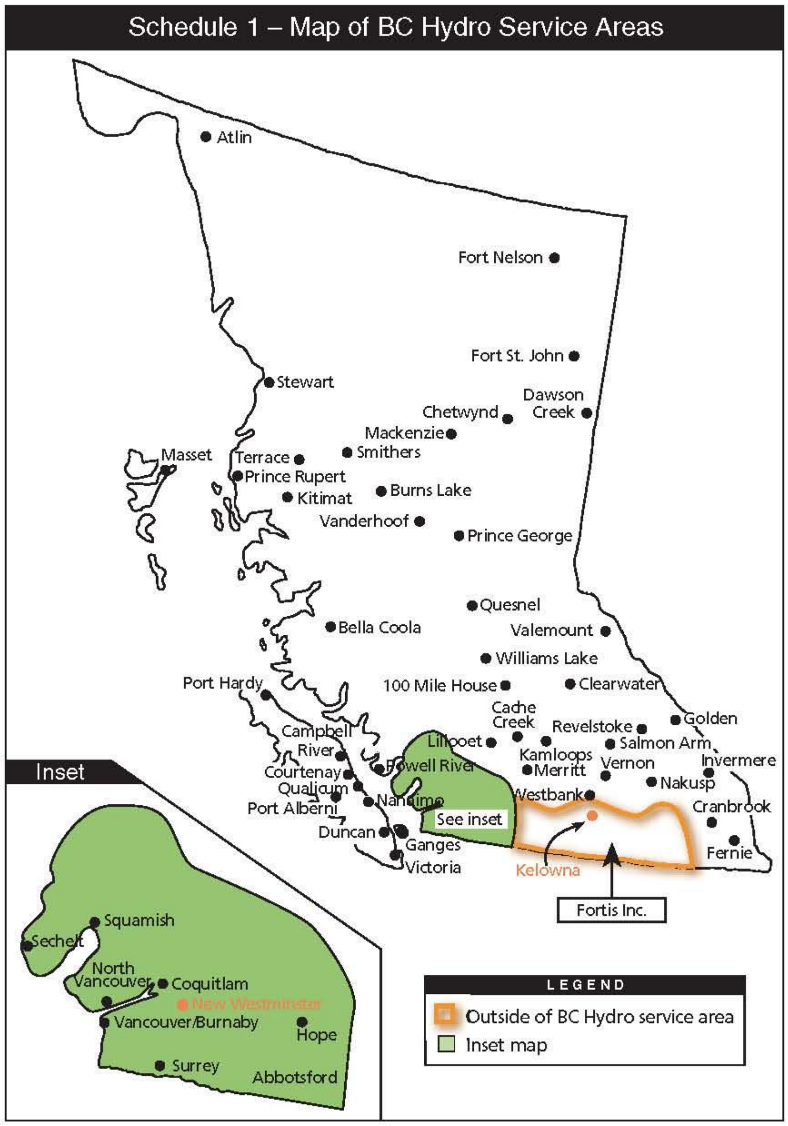
Transformers – The zero intercept method is suited to classify transformers because unit costs and sizes are well defined. The zero intercept method appears the best method, and even this method may be biased towards customer related costs. If a system were constructed to serve 1 kWh/yr per customer, you would not need the thousands of zero rated transformers, one would do. The minimum system approach appears to have a stronger bias to customer related costs, and therefore is seen as less appropriate than the zero intercept method.

Secondary – The minimum system method is practical for the secondary system, in that these facilities are designed and built to provide service to a customer (or a small group of customers) and therefore, these costs should be heavily weighted to customer related. While the zero intercept method provides results showing that approximately ¼ of these costs are demand related, from a practical perspective, smaller cables are not installed, and standard cables are used to avoid changing cables as load fluctuates.

Meters – Direct assignment of meters to customer related is the most practical approach. While the minimum system indicates that for very small customers, no meters are required, but this approach would classify all metering costs as demand related. While there is some merit to this interpretation, meters, for all practical purposes are customer related since every new residential customer gets a meter, regardless of their forecast load.

Summary – No one method was found ideal for all functions of the electric distribution system. Therefore, a method was chosen for each function to best reflect cost causation. As a result, a variety of methods was used to develop the recommendation for the classification of the costs of the electric distribution system.

6. Appendix A – Service Area Map



7. Appendix B – Bulk Transmission System Map

8. Functionalization of Distribution Property

			Functionalization Percent				**Functionalized Value (Net Book Value)**			
Profile_ID	SumOfNBV	Description	Primary	Transforme	Secondary	Meter	Primary	Transformer	Secondary	Meter
C11501	444,298	Land, Owned In Fee Simple	100.00%	0.00%	0.00%	0.00%	444,298	0	0	0
C11601	1,595,849	Land Rights, Conversion Only	100.00%	0.00%	0.00%	0.00%	1,595,849	0	0	0
C11602	10,597,771	Easement / Right-Of-Way	100.00%	0.00%	0.00%	0.00%	10,597,771	0	0	0
C11604	783,412	Land Rights, Other	100.00%	0.00%	0.00%	0.00%	783,412	0	0	0
C11626	1,280,943	Land Rights,Finite Life, 20Yrs	100.00%	0.00%	0.00%	0.00%	1,280,943	0	0	0
C11701	0	Clearing - Transmission	100.00%	0.00%	0.00%	0.00%	0	0	0	0
C11801	58,084	Recreation Facilities	100.00%	0.00%	0.00%	0.00%	58,084	0	0	0
C11901	625,692	Surfacing, Yard	100.00%	0.00%	0.00%	0.00%	625,692	0	0	0
C12002	279,848	Road, Paved / Gravel	100.00%	0.00%	0.00%	0.00%	279,848	0	0	0
C12005	16,894	Roads & Trails, Composite Pool	100.00%	0.00%	0.00%	0.00%	16,894	0	0	0
C12301	45,731	Pad, Helicopter	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C12401	9	Drainage System, Yard	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C12402	35,366	Landscaping	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C21001	57,390	Dam, Embankment / Concrete	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C21901	133,388	Roofs	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C22001	2,101,973	Plant, Concrete Or Steel	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C22002	123,027	Commercial, Concrete Or Steel	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C22004	36,289	Building, Wood	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C22005	5,613,285	Building, Composite Pool	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C22006	114,060	Equipment Shelter	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C22101	755,120	Office Trailer/Mobile Home	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C22201	0	Leasehold Improvements	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C22202	411,399	Leasehold Improvements	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C23601	956	Stoplogs, Steel	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C23604	0	Gate	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C23701	947	Trash Racks	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C23801	168,606	Cranes	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C24401	456,667	Dock / Wharf	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C25101	12,997,365	Structure, Support, Steel	100.00%	0.00%	0.00%	0.00%	12,997,365	0	0	0
C25102	2,035,477	Structure, Support, Wood	100.00%	0.00%	0.00%	0.00%	2,035,477	0	0	0
C25201	585,916,905	Pole Structures < 60Kv	79.84%	0.00%	20.16%	0.00%	467,783,497	0	118,133,408	0
C25202	576,733	Pole Structures > 60Kv	100.00%	0.00%	0.00%	0.00%	576,733	0	0	0

And the bottom section as follows:

C85001	143,138	Office Furniture	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C85002	17,345	Office Furniture	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C89501	6,949,446	Animal Preventative Equipment	0.00%	100.00%	0.00%	0.00%	0	6,949,446	0	0
C90000	0	Animal Preventative Equipment	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C90001	318,562,767	Reg-Demand Side Mgmt Prograi	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C90002	81,486	Reg-First Nations	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C90004	106,838	Water User Plans	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C99403	-129,966,637	Distribution - Cia	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C99404	-461,535	Transmission - Cia	0.00%	0.00%	0.00%	0.00%	0	0	0	0
C99405	-302,419	Substation - Cia	0.00%	0.00%	0.00%	0.00%	0	0	0	0
Total	3,436,742,048						2,070,098,641	732,585,599	289,507,285	113,831,279
							64.57%	22.85%	9.03%	3.55%