2015 RATE DESIGN APPLICATION (RDA): COST OF SERVICE (COS)

PREFERRED APPROACH AND SENSITIVITIES

BC hydro
FOR GENERATIONS

October 7, 2014

AGENDA

Approximate Time	Item	Panel
9 :00 – 9:10	Welcome	Anne Wilson
9:10 – 9:20	Background	Gord Doyle
9:20 – 9:50	Functionalization	Dani Ryan / Justin Miedema / Richard Cuthbert
9:50 – 10:30	Classification	Dani Ryan / Justin Miedema / Richard Cuthbert
10:30-10:45	Break	
10:45 – 12:00	Allocation	Dani Ryan / Justin Miedema / Richard Cuthbert
12:00 - 12:15	Next Steps	Anne Wilson

Background

- BC Hydro received a number of helpful stakeholder comments as part of the June 19th COS workshop
- There are three documents for this workshop:
  - The 19 June 2014 Consideration Memo concerning the first COS workshop
  - The Discussion Guide entitled "Preferred Options and Sensitivity Analysis"
  - This slide deck presentation
- At this time, BC Hydro rejects a marginal COS approach; this is addressed in the Consideration Memo
- BC Hydro has identified preferred options for each embedded COS topic
- In most cases, at least one additional option has been retained for sensitivity analysis

Background

- Revenue to Cost (R/C) ratios have been prepared for the preferred embedded COS approach based on F2013 financials and customer sales
- Based on input from this workshop BC Hydro will draft the COS study and prepare R/C ratios using F2016 information
- Draft COS study expected before the end of the calendar year

Seeking Stakeholder Feedback

From today's workshop:

- BC Hydro's preferred approach to COS
- Sensitivity analysis (refer to Discussion Guide)

On draft COS study

- Stakeholders will be notified when posted for comments

COS Topics

In the following slides BC Hydro presents its preferred option for each of the following COS topics:

Functionalization

- Demand Side Management (DSM)

Classification

- Heritage Hydro, Independent Power Producer (IPP), Smart Metering Infrastructure (SMI), and Distribution

Allocation

- Generation/Transmission and Distribution

FUNCTIONALIZATION

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DSM

BC Hydro's Preferred Option

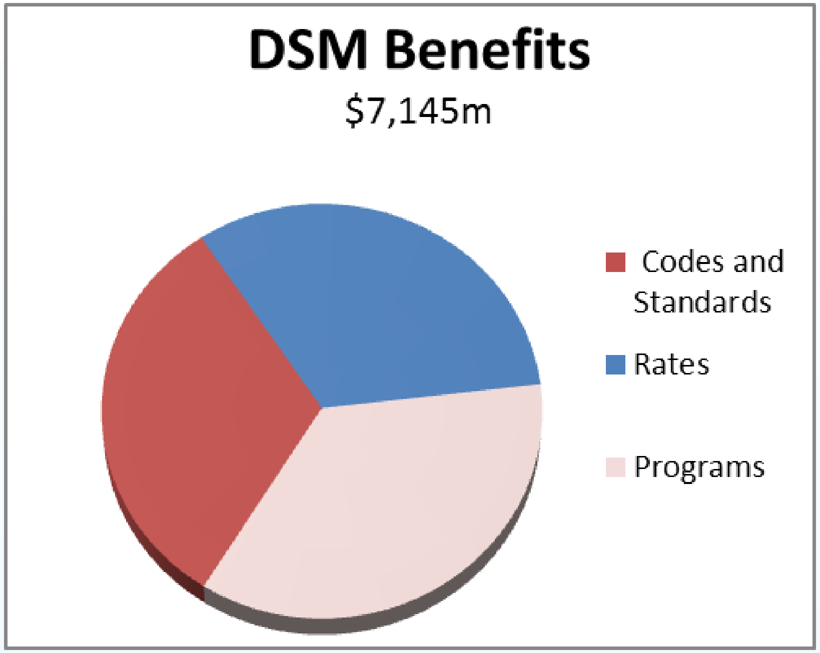
- Functionalize DSM as 90% generation, 5% transmission and 5% distribution to recognize the fact that DSM is acquired primarily to avoid generation-related costs

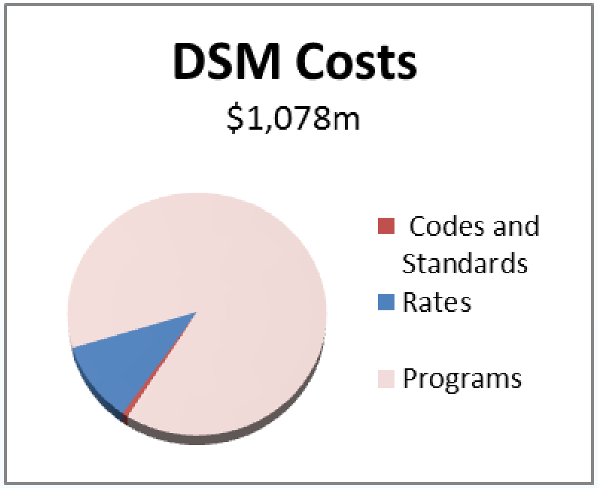
Alternative

- Directly assigning DSM costs to customer classes
- Fails to recognize the significant benefits that DSM activities provide to all rate classes

DSM – Benefits and Costs

- BC Hydro calculated the present value (PV) of DSM benefits and costs over the F2008 to F2016 period
- There would be a significant mismatch between benefits and costs if there was direct allocation
- For example, conservation rate structures, and codes and standards, account for 11% of the expenditures but produce 66% of the benefits





Note: The PV of benefits and costs has been calculated in $F2013 dollars

DSM – Benefits and Costs

Other examples of a mismatch between benefits and costs

Codes & Standards	Costs ($millions)	Benefits ($millions)
Residential	5	1,691
Commercial & Industrial Distribution	2	517
Industrial Transmission	0	61

Residential codes and standard initiatives are 0.4% of DSM costs, but account for 23% of total benefits

Programs	Costs ($millions)	Benefits ($millions)
Residential	228	565
Commercial & Industrial Distribution	436	831
Industrial Transmission	291	1157

Program expenditures for transmission voltage customers of $291 million produce over $1.1 billion in benefits for all ratepayers

CLASSIFICATION

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Heritage Hydro

- BC Hydro proposed three alternatives to classify heritage hydroelectric:
  1) Load factor approach
  2) Capacity factor approach
  3) Capacity factor approach with book value weighting
- BC Hydro carried forward two versions of Option 1, as well as Option 3
- Options 2 and 3 are very similar

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Heritage Hydro Stats

6 largest hydroelectric plants

Facility (F2016 data)	Energy Production (GWh)	Capacity (MW)	Capacity Factor	Book Value ($million)
GM Shrum	14,300	2,730	60%	655
Revelstoke	7,900	2,480	36%	1,485
Mica	6,900	2,720	29%	1,125
Kootenay Canal	3,100	590	60%	109
Peace Canyon	3,500	700	58%	323
Seven Mile	3,400	810	48%	291
Other	7,900	1,830	66%	1,450
Total	46,900	11,860	45%	5,438

- The 6 largest hydroelectric plants account for more than 80% of energy production and 75% of generation plant net book value
- Energy production volumes (GWh) are consistent with the F2016 Cost of Energy forecast in the F15/F16 Revenue Requirement Application model
- Capacity (MW) reflects the addition of Mica Units 5 and 6

Heritage Hydro

Option 1B:

- Since IPP costs are classified separately from hydroelectric, load served by IPPs can be excluded from the load factor calculation. The result is a load factor calculation based on load (almost entirely) served by hydroelectric
- This approach is used by: Newfoundland Power, Idaho Power and Avista Washington

F2016	Option 1A **Include** load served by IPP supply	Option 1B **Exclude** load served by IPP supply
Load Factor (Energy %)	61%	55%
Energy (GWh)	58,062	58,062 – 12,002 = 46,060
Capacity (MW)	10,813	10,813 – 1,272 = 9,541

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Preferred approach: Option 1B

Load factor approach is most appropriate because:

1) Hydroelectric capacity, which is used in the denominator of the capacity factor calculation, is not used exclusively to meet peak loads in the winter season. It is also used to optimize the hydroelectric system and to earn trade income for all ratepayers throughout the year.

2) Reduced variability
   - The addition of new units has a significant impact on the capacity factor calculation
   - Completion of Mica 5&6 in F2016 increases generation capacity by more than 800 MW thus decreases the system capacity factor

3) Three stakeholders supported a load factor approach at the June COS workshop

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Alternative: Option 3 – Capacity factor with book value

- Capacity factors can be calculated for the 6 largest hydroelectric plants
- Using F2016 forecast energy production normalizes the calculation and reduces variability.
    - BC Hydro's current year forecasts are developed using current basin conditions and inflows. Forecasts for future years are based on an average of streamflow conditions from 1973 – present (currently 40 year period)
    - Suggests about a 45% energy/ 55% demand classification, which is the same ratio used in the current COS study as per Direction #5 from the 2007 RDA
- Capacity factor calculations, shown in the Strawman proposal for the June workshop, were based on actual hydroelectric production in calendar 2013

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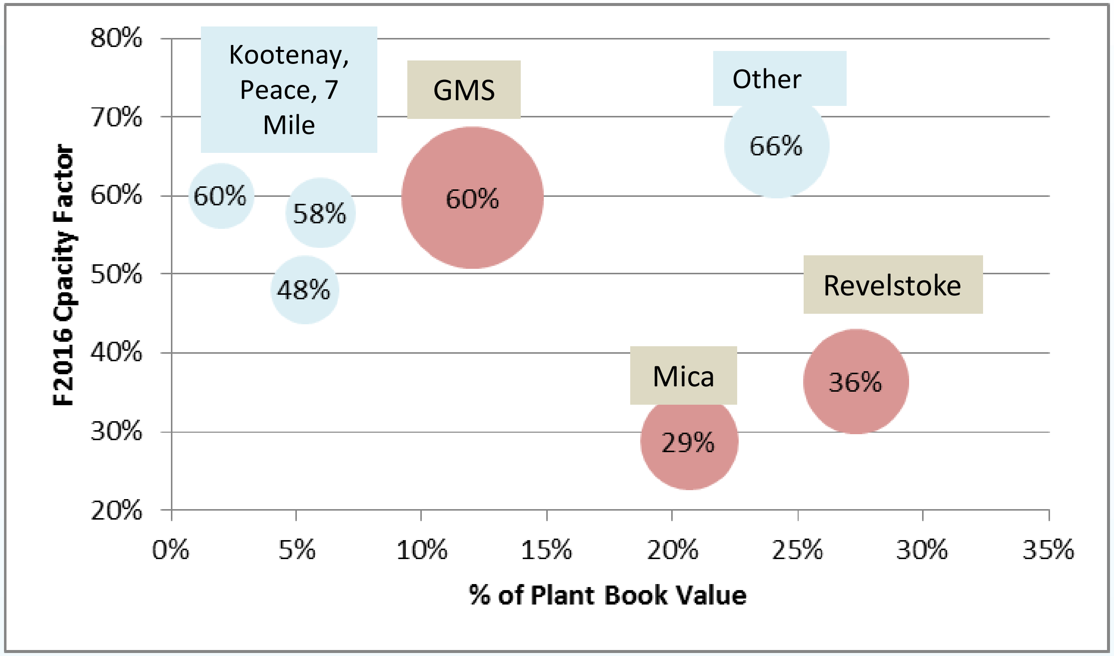
Alternative: Option 3 – Capacity factor with book value

- Relative to other hydroelectric facilities, Mica and Revelstoke have lower F2016 capacity factors (29% and 36%) and higher book values
- Weighting capacity factors by plant book values results in a lower overall capacity factor of about 46%, which suggests a 46% energy and 54% demand classification



Mica's capacity factor and book value reflect the addition of Mica 5 and 6 in F15 and F16 respectively

Larger circles indicate larger energy production from a hydroelectric facility

IPPs

At the June workshop, BC Hydro presented 5 options for classifying IPP costs:

- Option 1: Value of energy and capacity;
- Option 2: Value of capacity;
- Option 3: Contract structure;
- Option 4: Resource contribution;
- Option 5: Load factor

IPPs

- BC Hydro is no longer considering Options 3 and 4 for reasons discussed in the Consideration Memo
- Option 5 results in a 40% demand classification, which is not reasonable for intermittent resources (refer to the Discussion Guide)
- BC Hydro prefers Option 2
  - Option 2 better aligns with BC Hydro's reliance on IPP resources with high dependable capacity (Alcan, Island Generation and Biomass)
  - **Options 1 and 2 produce almost the same result**.

	Option 1	**Option 2**
% Energy Classification (with LRMC Prices)	Value of Energy / Value of Energy and Capacity	IPP Energy costs[1] / IPP costs
	94% Energy	93% Energy

[1] net of the Value of capacity

IPPs

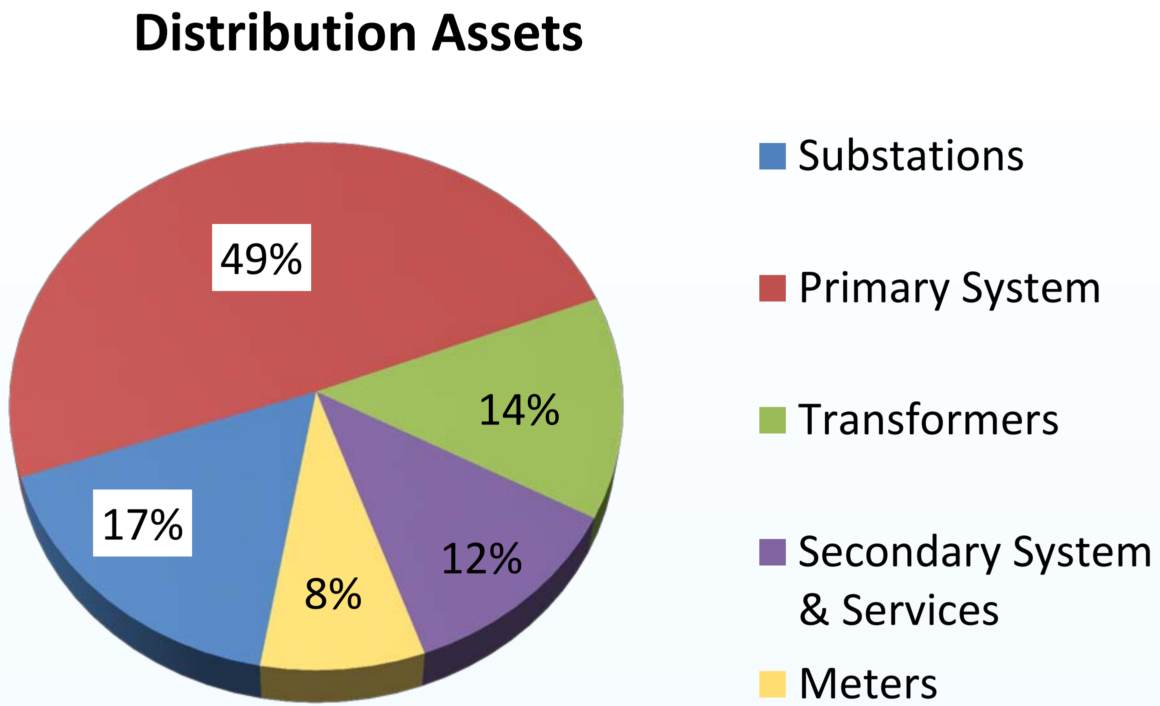
BC Hydro's Preferred Option

% Demand Classification

	Total Cost	Option 1	Option 2
Island Generation	59	7%	27%
McMahon	51	7%	12%
Biomass	257	7%	8%
Alcan	63	16%	14%
Wind	107	5%	5%
Small Hydro	332	3%	2%
Storage Hydro	106	5%	8%
TOTAL F16 COST AND WEIGHTED DEMAND ENERGY RESULTS	$975 MILLION		

Distribution Classification: Background

F2016 distribution costs are about $962 million
The graph below divides these costs by major distribution category using asset value



Substations and the primary System account for about 66% of distribution cost

Distribution Classification:
Substations and primary system

BC Hydro proposes:

- To classify **substations as 100% demand-related**
  - o All utilities in the LEIDOS study classify distribution substations as demand-related costs
- To classify the **primary system as 100% demand-related**
  - o The system is sized to meet the peak demands of customers. Primary feeders of similar size and cost are often installed to serve the same aggregate peak load but different numbers of customers

Distribution Classification: Transformers

BC Hydro proposes:

- To directly assign **transformers** to rate classes and assume a 50% demand / 50% customer classification
- Direct assignment methodology is discussed in the allocation section
- There is jurisdictional support for classifying transformer cost to both demand and customer; however the methods used are often complicated and produce variable results
    - Some utilities classify 100% demand, few as 100% customer and most others a mix of both
- **This asset category represents about 14% of distribution cost**

Distribution Classification:
Secondary and Services

BC Hydro proposes:

- To make a **high level assumption that 50% of the asset value is secondary and 50% services:**
  - o The secondary portion would be classified 100% demand-related
  - o Services would be classified 100% customer-related
- The secondary system includes assets (primarily poles, ducts and wire) between the transformer and the customer's service connection. More than one customer can be connected to the secondary system.
- BC Hydro records the combined asset value of the secondary system and services in the same financial accounts for the overhead (OH) and underground (UG) system
- BC Hydro cannot separately estimate the value of secondary and services; however, the number of km of installed cable is known for each
- **This asset category represents about 12% of distribution cost**

SMI CLASSIFICATION:
OPTIONS CONSIDERED

Option 1

100% customer-related

Consistent with historical treatment of metering costs, recognizing that number of customers drives meter spending and has jurisdictional support

Preferred alternative

Option 3

70-30 Customer / Energy split

Recognizes drivers of expenditures as well as offsetting system benefits

Rejected alternative

Option 2

100% energy related

There is not much difference in R/C ratio impact between Option 1 and Option 3: refer to Discussion Guide

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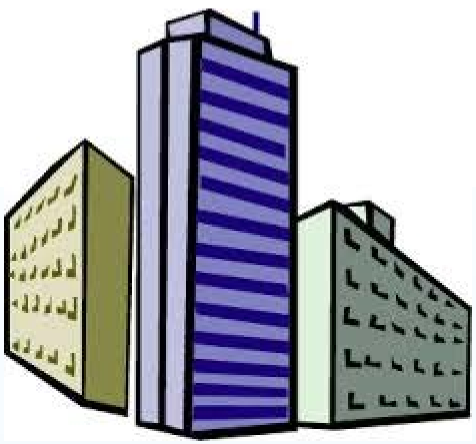
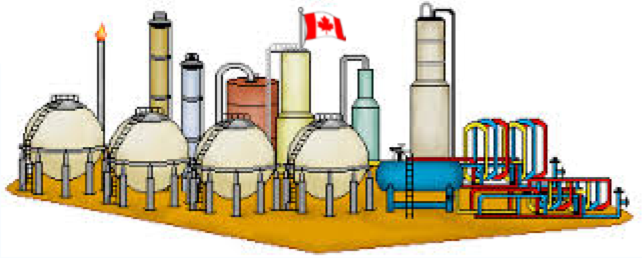
ALLOCATION





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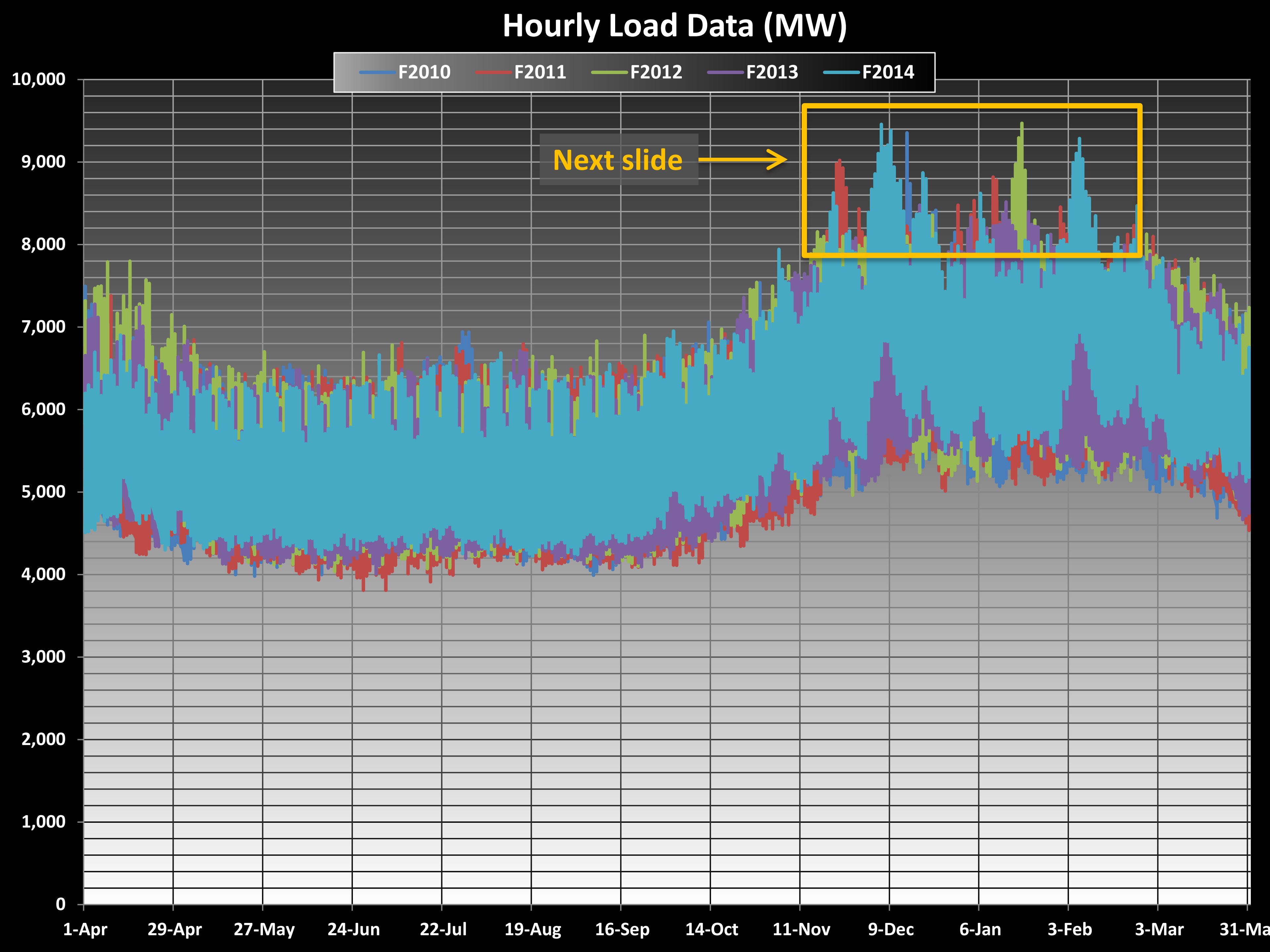
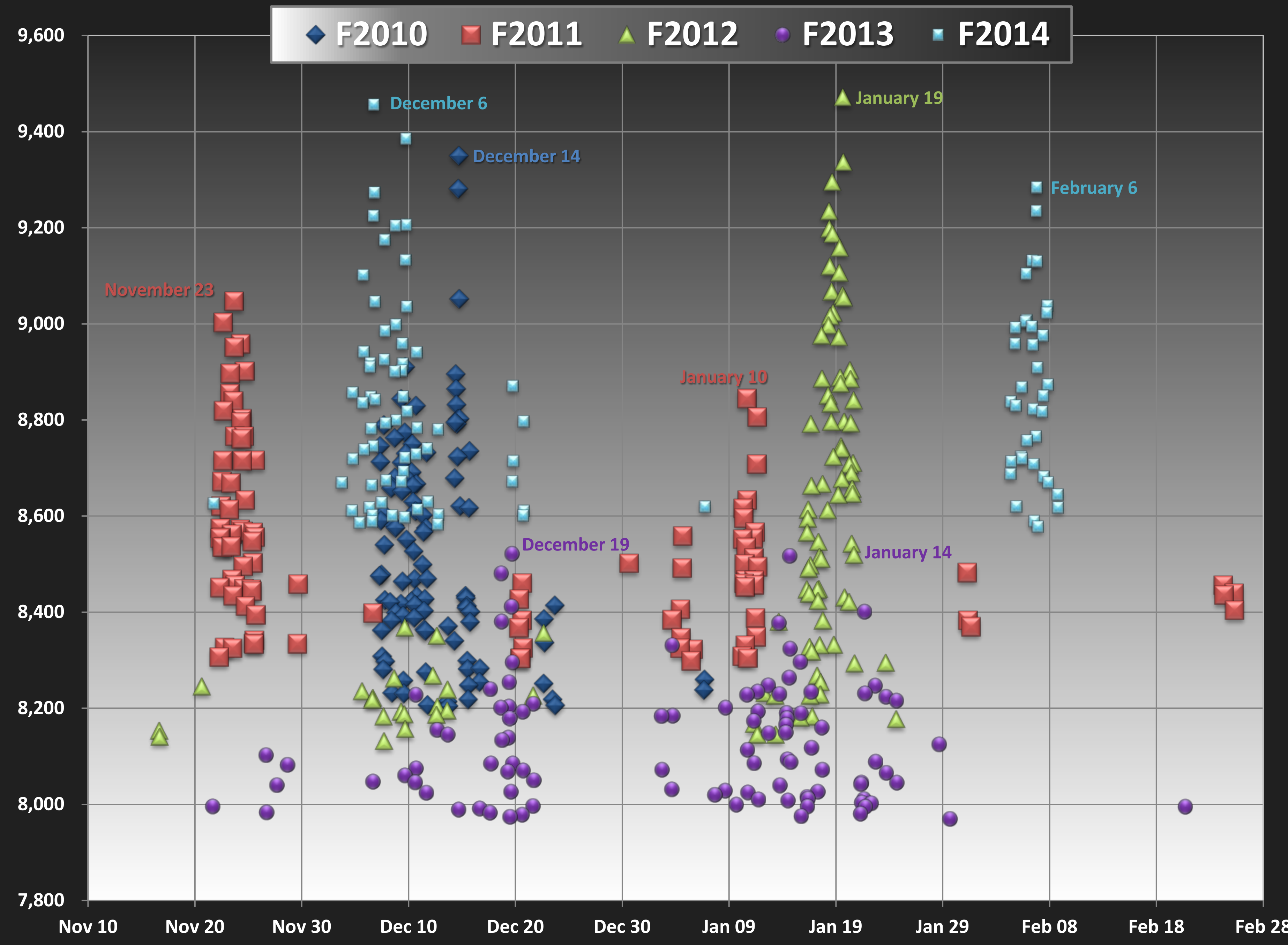
Generation & Transmission Allocation

BC Hydro's preferred option:

- Continue with 2007 BCUC RDA decision to use a 4 Coincident Peak (CP) methodology to allocate generation and transmission demand costs


Hourly Load Data (MW)
F2010
F2011
F2012
F2013
F2014
Next slide
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1-Apr
29-Apr
27-May
24-Jun
22-Jul
19-Aug
16-Sep
14-Oct
11-Nov
9-Dec
6-Jan
3-Feb
3-Mar
31-Ma

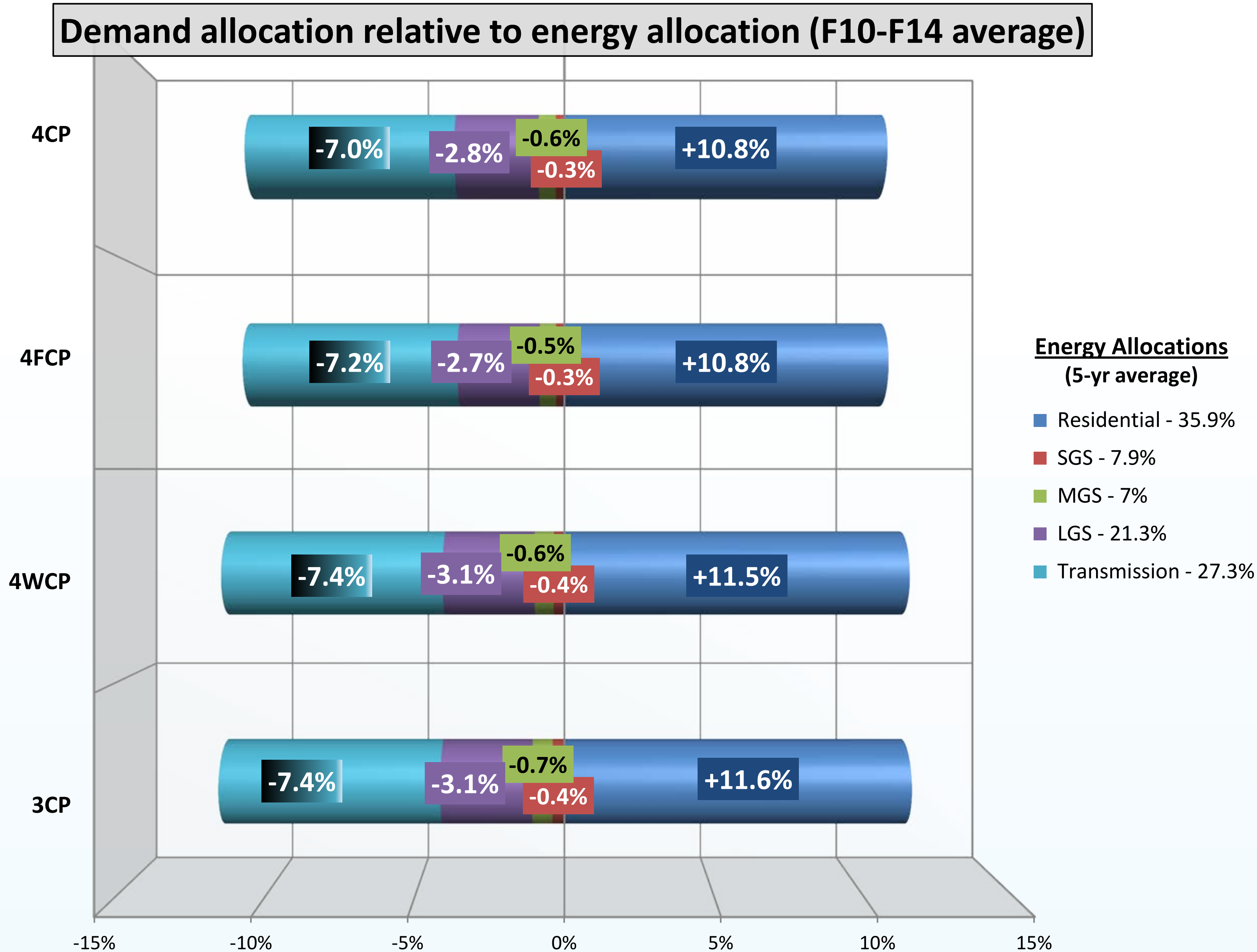
Top 100 annual peaks (MW)



Generation & Transmission Allocation

Allocator options

Name	Description
4CP	**BC Hydro's Preferred Option** 5-year average of 4 monthly peaks for November through February
4FCP	5-year average of 4 semi-monthly peaks for December and January ("fortnight CP")
4WCP	weighted 5-year average of 4 monthly peaks for November through February, using probability of peak during last 30 years
3CP	5-year average of 3 monthly peaks for November through January



Demand allocation relative to energy allocation (F10-F14 average)
4CP
-7.0%
-2.8%
-0.6%
-0.3%
+10.8%
4FCP
-7.2%
-2.7%
-0.5%
-0.3%
+10.8%
4WCP
-7.4%
-3.1%
-0.6%
-0.4%
+11.5%
3CP
-7.4%
-3.1%
-0.7%
-0.4%
+11.6%
-15%
-10%
-5%
0%
5%
10%
15%
Energy Allocations
(5-yr average)
Residential - 35.9%
SGS - 7.9%
MGS - 7%
LGS - 21.3%
Transmission - 27.3%

Transmission Allocation – radial lines

- The LEIDOS report recommended:

  “For transmission/subtransmission assets that essentially serve as a radial high voltage distribution system, we recommend that the Demand Only method for classification should continue to be used and consideration should be given to using 1 non-coincident peak (NCP) as the demand allocator “

- At the June workshop BC Hydro stated it would investigate the treatment of radial transmission lines and report back to stakeholders.

  - BC Hydro identified more than 100 radial transmission lines, which represent between 5 - 10% of transmission system book value

  - Since these are a relatively small proportion of the transmission system, BC Hydro does not believe customized treatment is warranted and instead proposes to allocate these assets using the same allocator as the overall transmission system

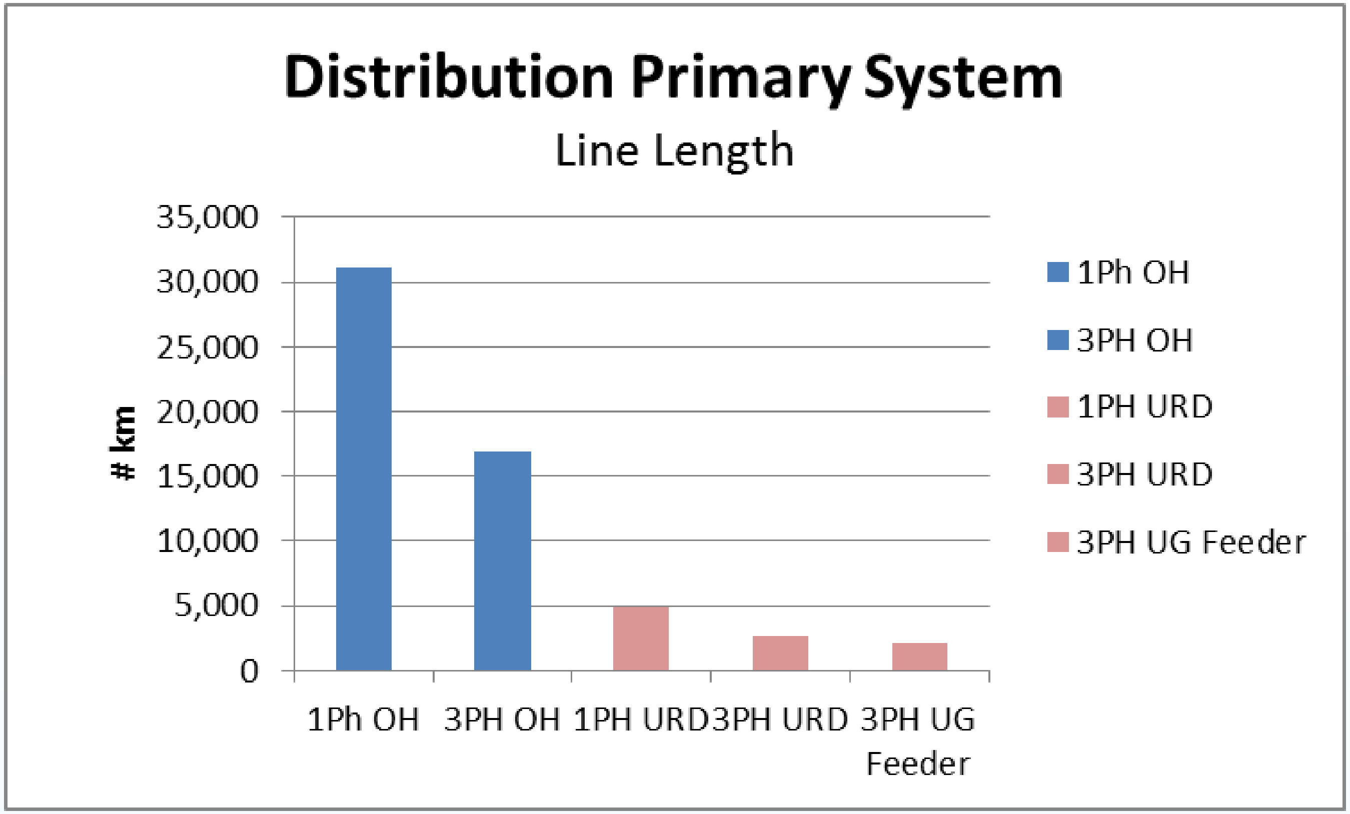
Distribution Allocation:

- Option #1: At the June COS workshop BC Hydro indicated it would investigate direct assignment methods for the distribution system
- Option #2: If direct assignment approach is not feasible, BC Hydro would classify distribution assets (e.g., substations, primary, secondary, transformers, meters) as either entirely demand-related or customer-related
- For those assets classified as demand-related, BC Hydro would continue the current Non Coincident Peak (NCP) allocation
- For those assets classified as customer-related, BC Hydro proposed allocation methods based on the number of customers or weighted customers (i.e. metering) where appropriate

Primary System: Background

- The primary system accounts for about 49% of distribution cost
- BC Hydro has more than 1,500 primary distribution feeders
- At a high level, direct assignment is accomplished by valuing each primary distribution feeder and then determining each rate class' share of each feeder's peak load
- With smart metering, BC Hydro now has the ability to estimate loads by rate class on a feeder by feeder basis

Primary System: Background



Observation: most of the line length comes from the overhead system.

OH = Overhead, UG = Underground, URD = Underground distribution

Primary System: Option 1 (Direct Assignment)

Step 1: Determine the value of each feeder

- BC Hydro does not track the depreciated value of individual feeders on the distribution system

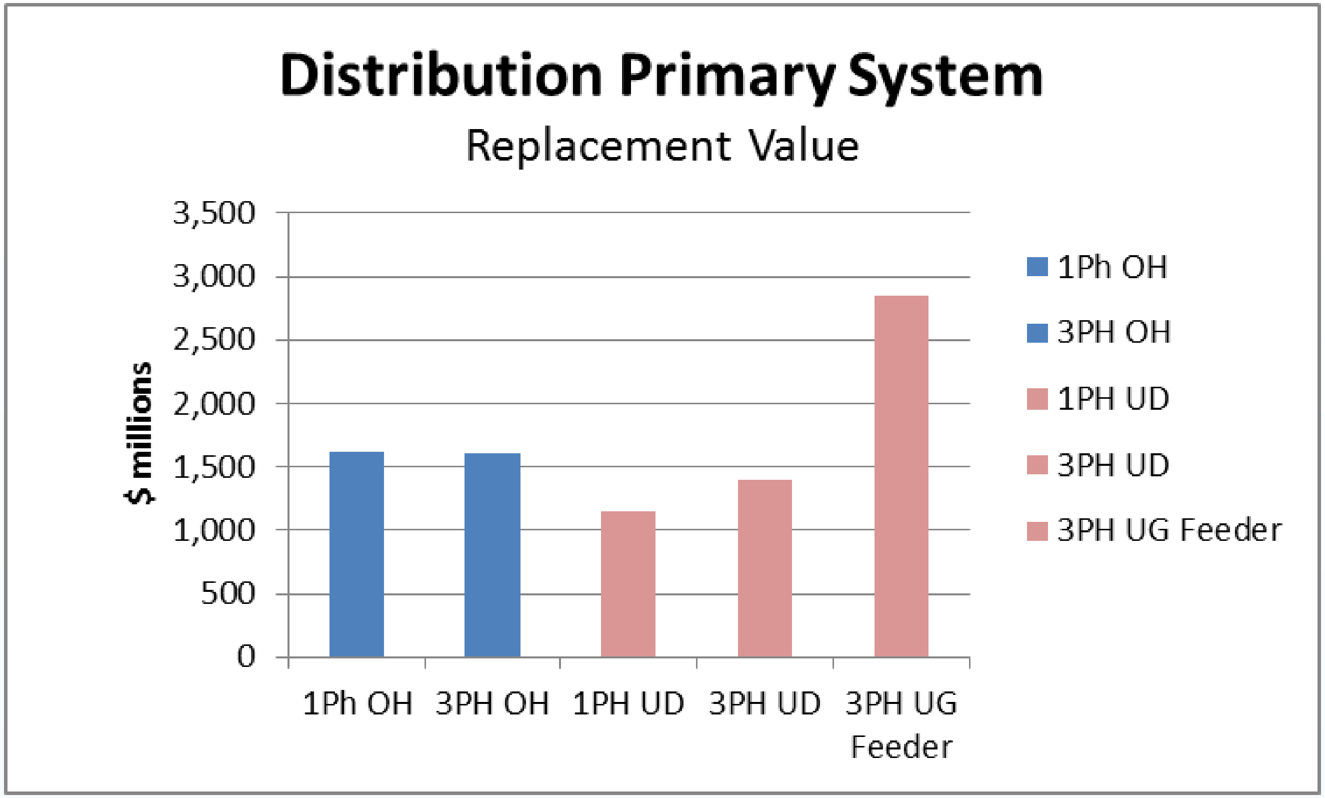
Two ways to estimate value:

a) Using replacement cost (no deflation).

Example for a 1 phase OH feeder that's 7km long**:**

7 km * 1PH OH $70,000/km = $490,000

Primary System: Option 1



$/km construction costs are estimated to be 10-15 times higher on the underground system than the overhead system. This raises the underground system's total replacement value relative to the OH system

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Primary System: Option 1

b) Using replacement cost (with deflation to estimate a true book value)

- There are issues with using replacement costs (see BC Hydro's June 3, 2014 covering letter regarding COS Methodology Assessment)
  - One solution is to deflate the replacement costs to estimate the net book value of the asset

Issues with this approach:

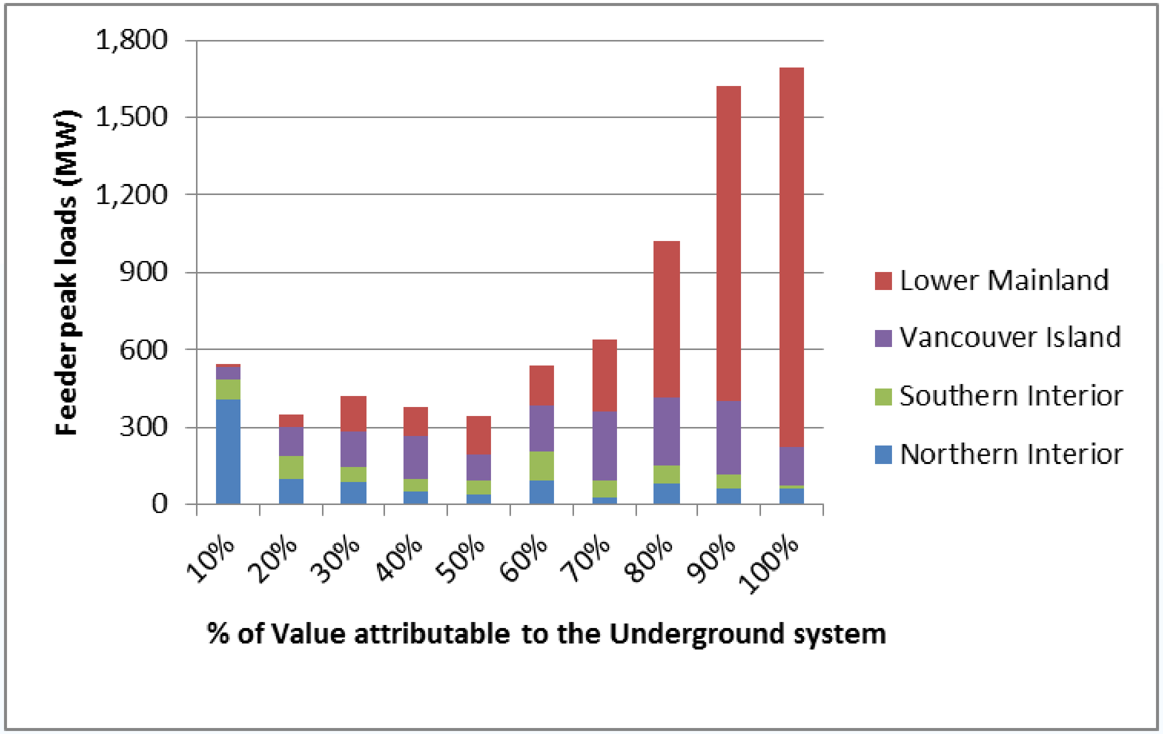
- If deflation is used, what cost index should be used?
- How many years should the asset be deflated for?
- BC Hydro does not know the average age of each feeder. This analysis is complicated because different feeder assets have different ages. There are hundreds of thousands of different assets on the primary distribution system. In addition, BC Hydro does not know the actual age of older assets. Better data exists for those assets less than 30 years old
- The OH system is believed to be about ~10-15 years older on average than the UG

Primary System: Option 1

DATA GATHERING

Data Category	Data collected	Source
Assets	• km of 1PH OH, 1PH UG for each feeder • km of 3PH OH, 3PH UG for each feeder • age of major assets including poles & transformers	BCH asset records
Load	• peak load (kW) by rate class for each feeder	SMI and load research data
Book Value of feeders	Not available	N/A
Replacement Costs of feeders	• $/km 1PH OH, 1PH UG • $/km 3PH OH • $/km 3PH UG primary, subdivision (includes material, labour, vehicle and civil costs)	High level province wide estimates developed using "typical" construction costs
Asset Age	Age distribution for poles and transformers Accuracy of older data is questionable	BCH asset records

Primary System: Option 1



Observations:
Feeders that are primarily underground are found in the Lower Mainland.

Feeders that are almost entirely overhead are primarily found in the Northern Interior region.

Note:
- Feeders have been grouped into 10 different categories.
- Example: the first bar of the graph illustrates the sum of peak loads on feeders with <10% of their value from the UG system and >90% of their value from the OH system
- Replacement costs have not been deflated

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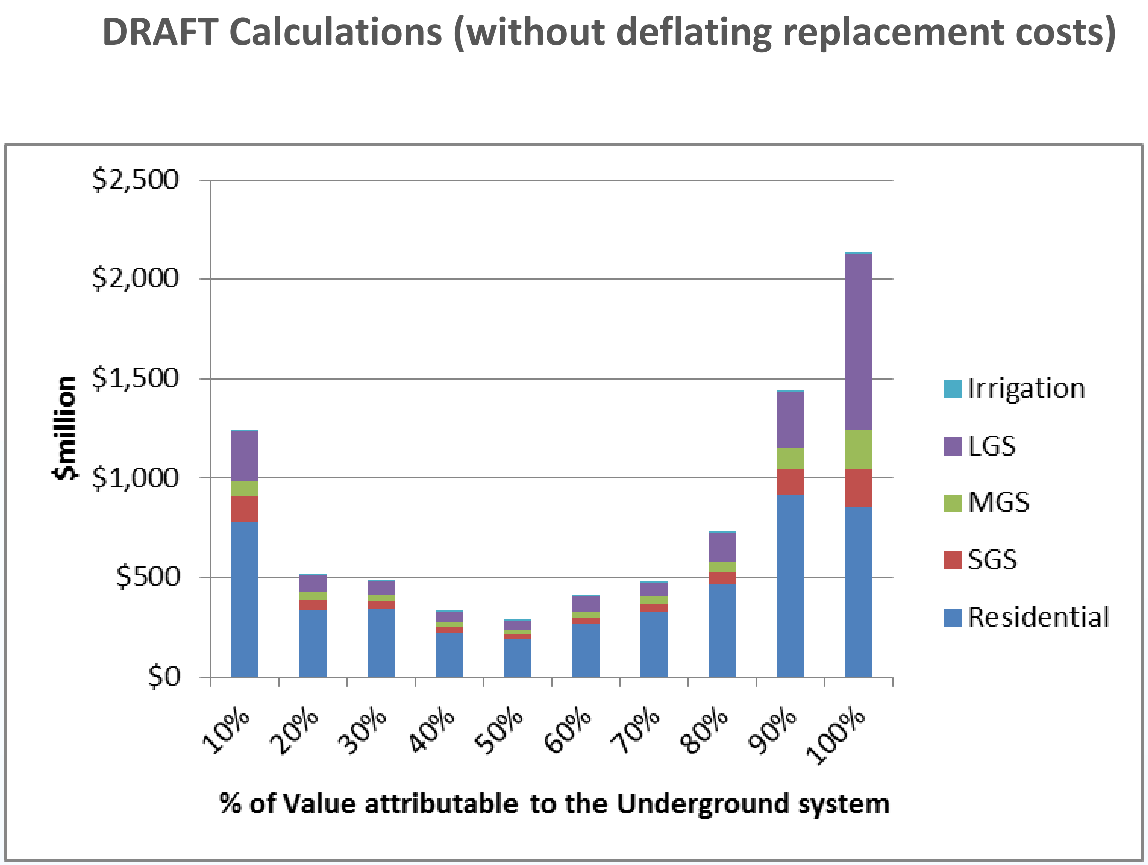
Primary System: Option 1

Step 2: Determine each rate class' contribution to each feeder's peak demand

- Example: if the feeder is valued at $7 million and the residential class accounts for 20% of the feeder's peak load, residential customers are assigned a pro-rata share of the cost ($1.4 million)
- Process repeated for each of the ~1500 distribution feeders
- Class contributions to the feeder peak are developed using a mix of hourly and daily data from the billing system and SMI
- Replacement costs have not been deflated

Primary System: Option 1



Observations:
In aggregate, residential customers would be assigned 65% of OH system costs and 54% of UG system costs.

LGS customers would be assigned 18% of OH system costs and 29% of UG system costs.

Feeders have been grouped into 10 different categories.
Example: the first bar of the graph illustrates cost allocation to rate classes for those feeders with <10% of their value from the underground system and >90% of their value from the overhead system.

Primary System: Option 1

ISSUES WITH THIS APPROACH

- **Labour cost** assumptions vary greatly by region and cannot be averaged across BC Hydro's service area with any certainty to develop $/km costs. These estimates are a key component of replacement costs, especially on the UG system
- **Replacement cost** has been used as a proxy for book value of individual feeders because costs of distribution assets are aggregated (and not individually extractable) in the accounting system. Using replacement costs can may skew the analysis (see slide 37)
- **Customer contributions** to construction are not tracked on a feeder basis and so this amount is assumed to be zero for the purpose of this analysis. This would have the impact of not properly reflecting BC Hydro's reduced cost of any particular feeder construction. In addition, changes in contribution policy over time may skew the analysis
- **BC Hydro does not know street lighting or other unmetered loads** on a feeder by feeder basis. A manual adjustment would need to be made to the analysis to account for this

Primary System:

BC Hydro’s preferred approach: Option 2

- Although BC Hydro now has more detailed load information on a feeder-by-feeder basis, there are significant issues with using replacement costs to value individual feeders and allocate those costs to rate classes

- For this reason, BC Hydro does not believe a direct assignment approach is reasonable for the primary system

- Instead of direct assignment, BC Hydro proposes to classify the primary system as 100% demand and use a NCP allocator

- Most utilities surveyed use NCP as a demand allocation factor as opposed to CP

Primary System:

Rate Class	Option 1 Direct Assignment Method	Option 2 F2013 NCP allocator
Residential	59%	54%
SGS	9%	10%
MGS	7%	9%
LGS	24%	25%
Irrigation	0%	0.4%

- There is not much difference between the direct assignment method (Option 1) and BC Hydro's preferred approach (Option 2)

Distribution Transformers

- At the June workshop BC Hydro committed to examine transformers in more detail
- There are about 300,000 BC Hydro owned transformers in service
- 90% OH, 10% UG
- The number and size of transformers on the system is driven by both customer loads and the # of customers

100% Demand

55% residential

25% LGS

How to classify

Distribution Transformers?

100% Customer

89% residential

1% LGS

- The following slides include **preliminary analysis** that directly assigns transformers to rate classes

Distribution Transformers

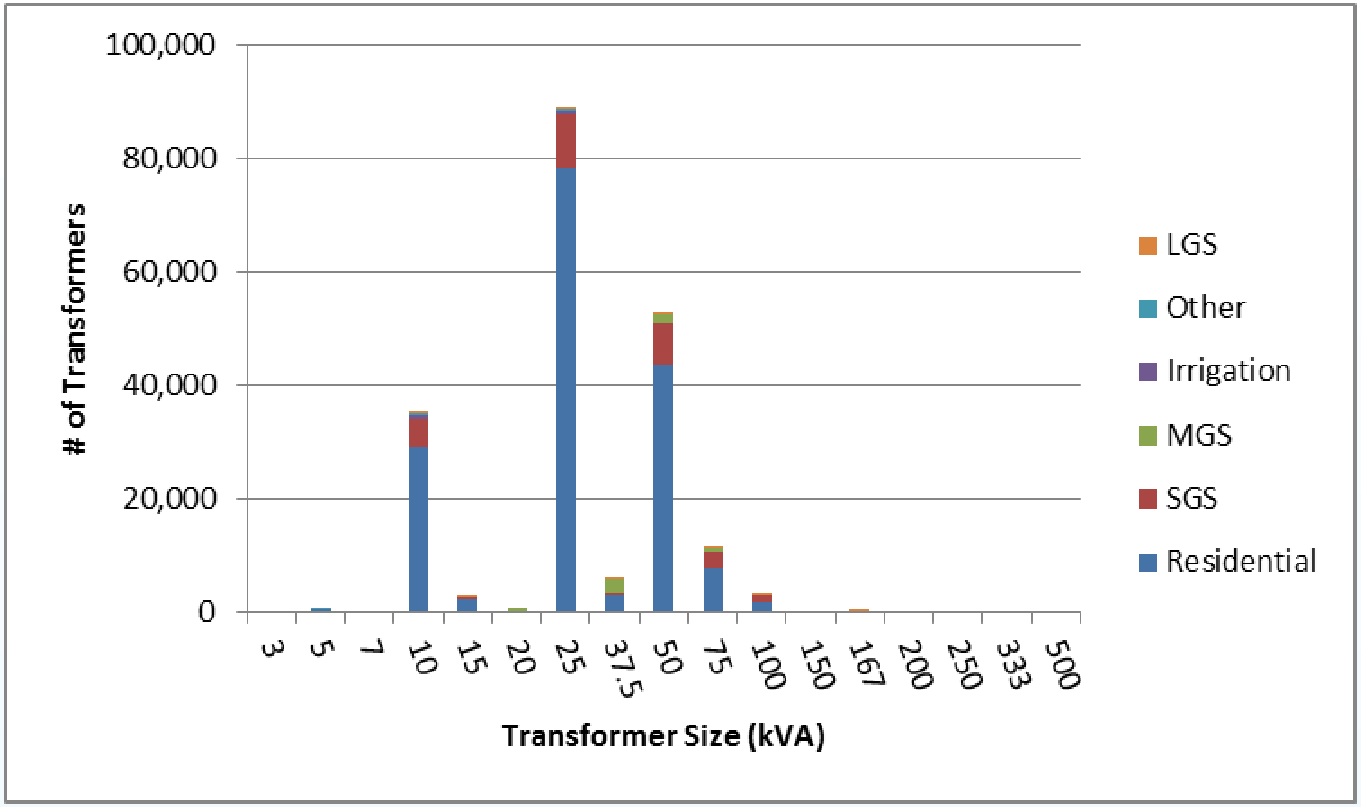
Option 1: Direct assignment of Transformers to Rate Classes

- Approximately 270,000 BC Hydro owned distribution transformers were analyzed using GIS customer connectivity and transformer device information
- This was done across the ≈1,500 distribution feeders/circuits within the distribution system
- BC Hydro assigned transformers to rate classes using information from BC Hydro's billing system including the customer's rate, heating code and premises code
- Where multiple classes share a transformer, a pro rata allocation based on one year of energy sales was used. Energy sales for 2014 were used because hourly SMI data was not available for all customers for summarization

Distribution Transformers

Option 1:

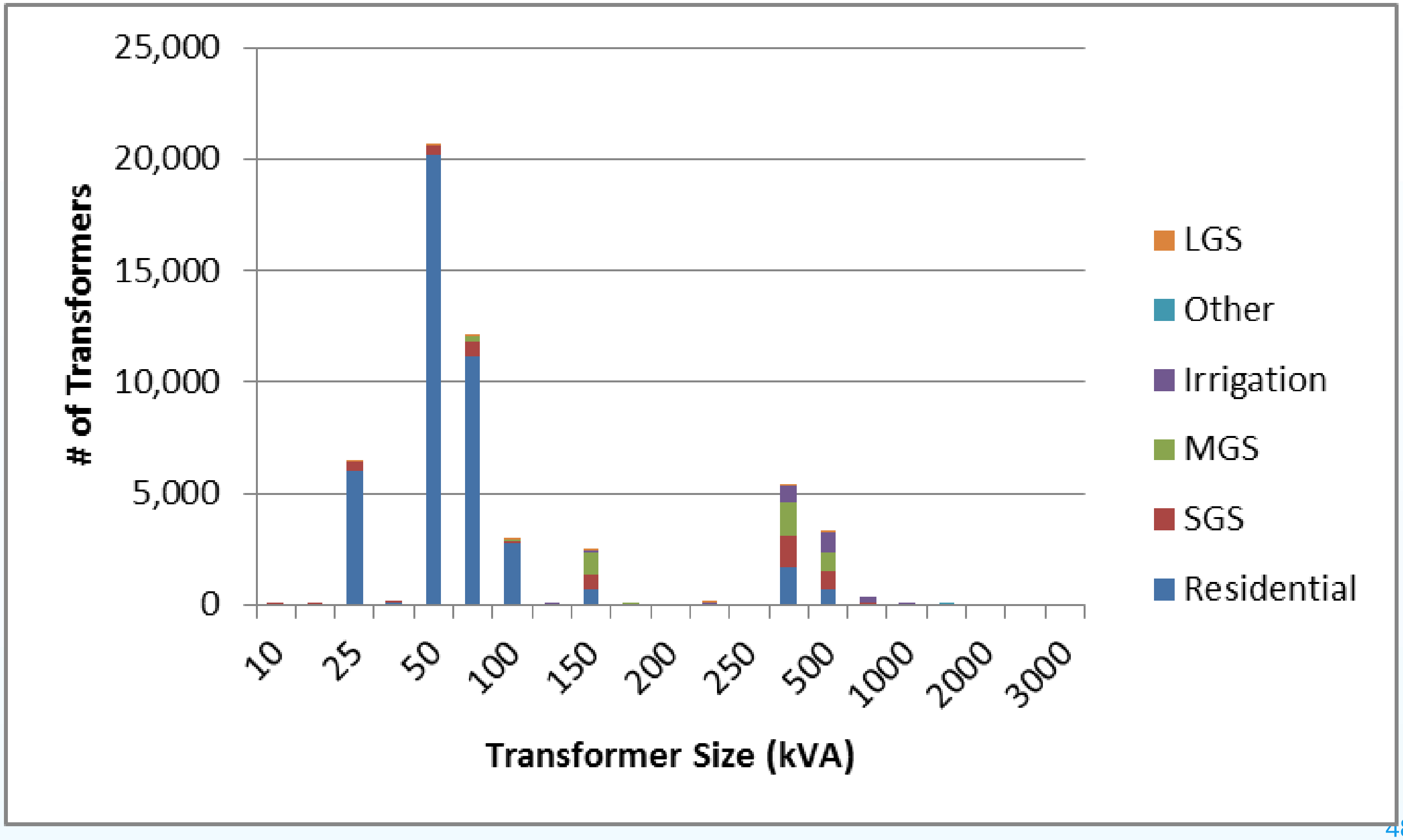
- The graph below shows a distribution of OH transformers and the number of transformers assigned to each rate class.



Distribution Transformers

Option 1:

- The graph below shows a distribution of UG transformers and the number of transformers assigned to each rate class



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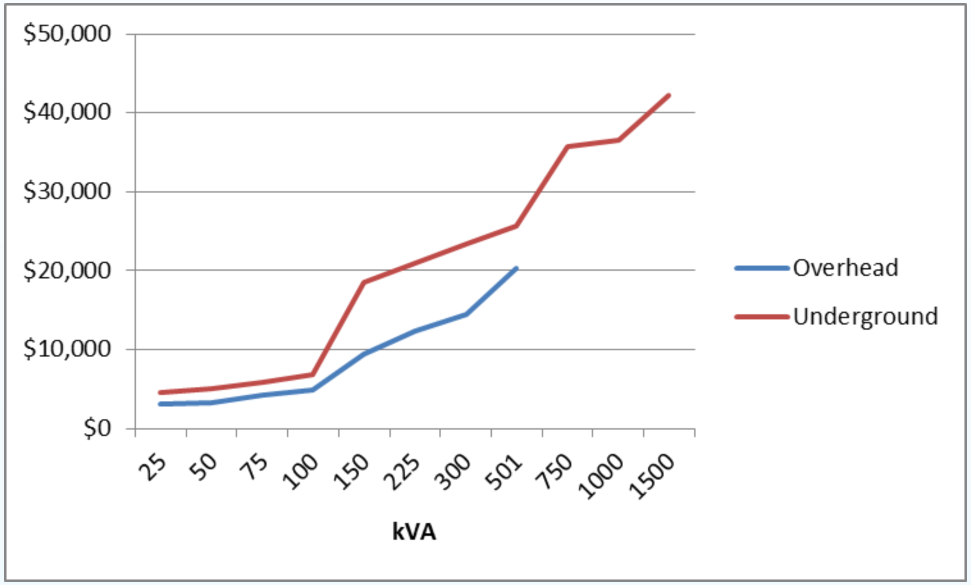
Distribution Transformers

Option 1:

- The next step was to weight these transformer assignments by the value of individual transformers
- Replacement costs including material, vehicles, and labor were estimated for different sized overhead and underground transformers
- Unlike the primary system, material costs account for about 90% of transformer related costs

Replacement costs for different sized transformers



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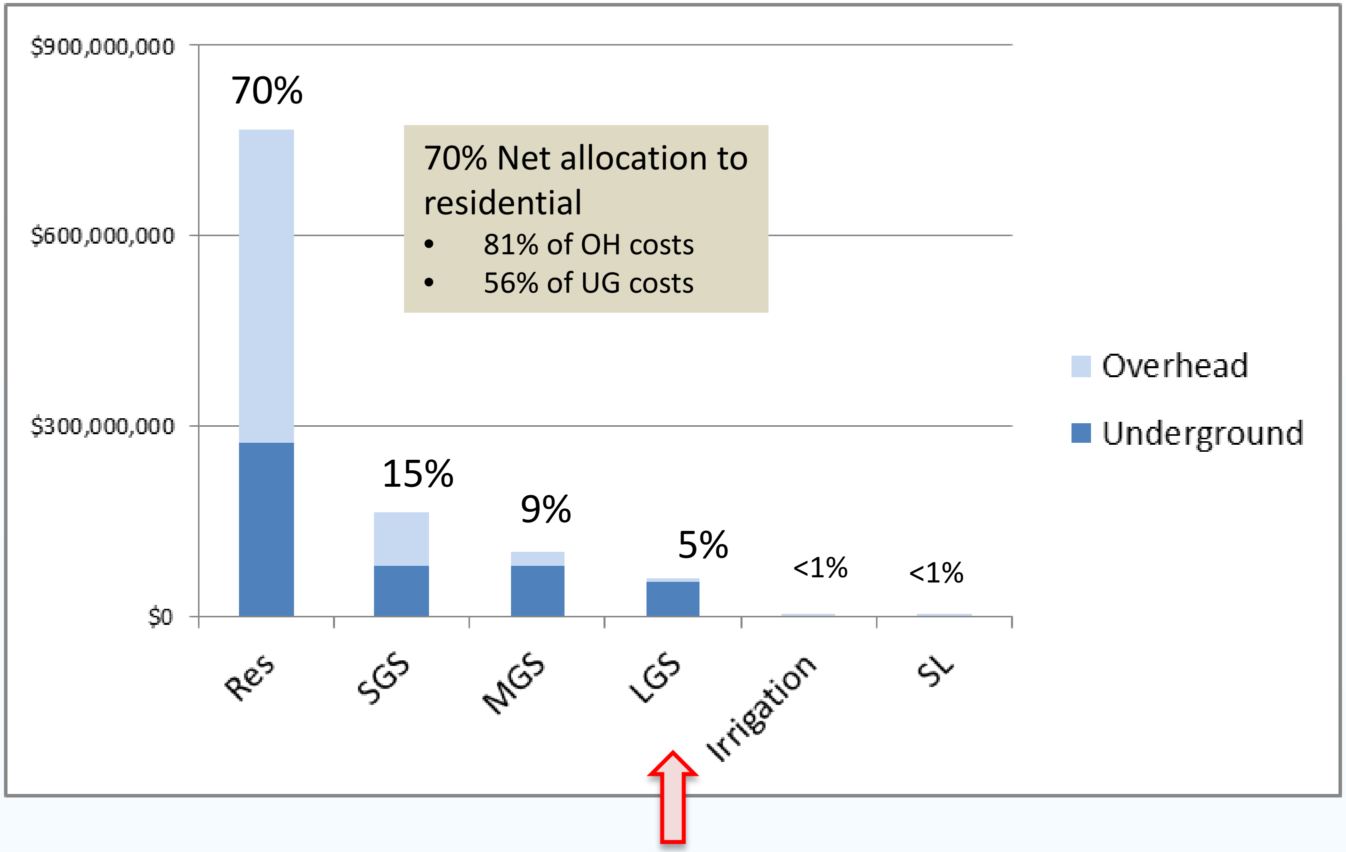
Distribution Transformers

Option 1



Relatively small allocation to LGS customers because most own their transformers

Distribution

Issues with Option 1

- Not all transformers are tracked individually in BC Hydro's asset system
- Data quality including accurate recordings of transformer sizes and phase levels can be an issue
- Using replacement costs may skew the results. However, BC Hydro believes it is reasonable to assume that the cost of different sized transformers has increased proportionately over the past 20 years

Possible Refinements

- Hourly SMI data can assist in identifying, improving, and verifying GIS connectivity and transformer size errors going forward
- CP and NCP transformer loads could be calculated with hourly SMI data going forward
- Cost differences between 1 and 3 phase transformation could be reflected – analysis to date assumes all OH transformers < 100 kW are single phase

Distribution Transformers

Option 1: Direct Assignment

- In summary, the proposed direct assignment approach recognizes that there is both a demand and customer component to transformation
- For rate design purposes, such as determining a cost basis for basic charges and demand charges, the directly assigned costs would still be classified. BC Hydro proposes to classify transformers as 50% demand / 50% customer

- **Option 2: Allocate based on a 50% demand and 50% customer classification**

  - Allocate the demand portion using NCP allocator
  - Allocate the customer portion using a customer allocator

Distribution - Secondary and Services

- BC Hydro proposes to make a high level assumption that 50% of the asset value is secondary and 50% services
  - The secondary portion will be classified as 100% demand and allocated with an NCP allocator
  - Since services benefit individual customers they will be classified as 100 customer and allocated accordingly
- This category represents less than 15% of overall distribution rate base

DISTRIBUTION CLASSIFICATION AND ALLOCATION SUMMARY:

BC Hydro proposes:

- To classify substations as 100% demand-related, allocation using NCP
- To classify the primary system as 100% demand-related, allocation using NCP
- To use a direct assignment method for transformers

80% of Distribution Rate Base

- To classify secondary / services as 50% demand and 50% customer using appropriate demand/customer allocators
- To classify meters as 100% customer, allocation on a weighted customer basis

20% of Distribution Rate Base

F2013 R/C RATIOS

The table below shows the draft R/C ratio impact of BC Hydro's preferred options on the F2013 COS study

Customer Class	Base F2013 R/C Ratio (%)	Using Preferred Options (%)
Residential	89.8	91.0
SGS Under 35 kW	126.7	123.8
MGS	120.80	116.4
LGS	102.1	101.9
Irrigation	86.6	83.5
Street Lighting	115.7	116.5
Transmission	104.4	103.6

NEXT STEPS

- Additional work will be required to develop the draft COS study
  - This includes incorporating:
    - changes that may result from stakeholder feedback
    - street lighting costs along with evaluating whether a separate rate class should be created for BC Hydro owned street lights
    - refined distribution classification and allocation analysis

NEXT STEPS – STAKEHOLDER FEEDBACK

Gathering input from this workshop	Timing
Seeking feedback on BC Hydro preferred options and sensitivity analysis	Mid November - 30 day comment period following BC Hydro's posting of workshop notes on or about 17 October 2014
Gathering feedback on draft COS study	**Timing**
BC Hydro incorporating feedback and then posting draft COS study with excel version	By end of calendar year
Stakeholder feedback on draft COS study	Final comment period in December/January

THANK YOU

SEND COMMENTS TO:
bchydroregulatorygroup@bchydro.com

For further information,
please contact:

BC Hydro Regulatory Group
bchydroregulatorygroup@bchydro.com
(604) 623-4046

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