2018 ISO Tariff Application — Appendix D Transmission System Cost Causation Study 2018 Update

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D-1 Executive Summary

The scope of this transmission system cost causation study update ("2018 Update") involves updating the Alberta Transmission System Cost Causation 2014 Study ("2014 Study") prepared by London Economics International ("LEI"). The 2014 Study performed analysis in four key areas: (i) functionalization of transmission facility owner ("TFO") related capital costs, for both existing and planned assets (until 2016), (ii) functionalization of related operations and maintenance ("O&M") costs, (iii) classification of all costs functionalized as bulk and regional, and (iv) implementation considerations, i.e., discussion of the potential impact of implementing functionalization and classification results on rates/recovery of the revenue requirement. This 2018 Update performs identical analysis using additional data that became available since the 2014 Study was performed.

The 2014 Study defined the three transmission functions: bulk, regional and point of delivery ("POD"). A high voltage system carrying large amounts of electricity over long distances is defined as serving the bulk function. A regional system transmits electricity from the bulk system to load centers with numerous points of delivery. Finally, a POD system serves distribution utilities or industrial customers that connect directly to the transmission system.

As was done in the 2014 Study, this 2018 Update first functionalizes capital cost, then functionalizes O&M cost, then combines capital cost and non-capital cost functionalization using ratio of capital cost to non-capital cost, and then finally incorporates regulated generating unit connection charge ("RGUCC") and Fort McMurray West 500 kilo Volt ("kV") transmission project ("FMW") charge to calculate final functionalization.

Capital cost functionalization results for the filing period of 2018-2020 are presented in Table D-1 below. These results in Table D-1 do not include impact of RGUCC and of FMW.

Table D-1 - Capital cost functionalization results

Function / Year	2018	2019	2020
Bulk	57.3%	56.4%	55.3%
Regional	23.5%	23.5%	23.6%
POD	19.1%	20.1%	21.2%

Table D-2 presents O&M functionalization results for the combined TFOs until 2020. The results include information from all four largest TFOs up until 2017.

Because the 2018 Update is updating functionalization for 2018-2020, and 2018-2020 O&M projections were not available at the time this analysis was performed, the AESO used following approach to forecast O&M functionalization for 2018-2020. Table D-2 shows a decreasing trend in bulk and regional functionalization, and increasing trend in POD functionalization from 2015 to 2017. The AESO therefore used this trend from 2015 to 2017 to forecast O&M costs functionalization for 2018-2020 presented below in Table D-22. The 2014 Study used 2014 O&M cost functionalization for 2015 and 2016.

Table D-2 - O&M functionalization results

Function / Year	2018	2019	2020
Bulk	23.4%	23.2%	23.1%
Regional	36.3%	35.7%	35.2%
POD	40.4%	41.0%	41.6%

After separately functionalizing capital and O&M costs, the results were combined using TFOs' non-capital to capital ratios in respective years (as presented in Table D-3 below).

Table D-3 - Ratio of non-capital to capital costs for TFOs

Type / Year	2018-2020
Non Capital	17.1%
Capital	82.9%

The combined functionalization results are shown in Table D-4 below.

Table D-4 - Combined O&M and capital cost functionalization

Function / Year	2018	2019	2020
Bulk	51.5%	50.7%	49.8%
Regional	25.7%	25.6%	25.6%
POD	22.8%	23.7%	24.7%

The RGUCC arises from TFO-owned facilities providing system access to previously regulated generators. This annual revenue is deducted from the bulk system annual revenue requirement since generation related costs and revenues are assigned to bulk function. FMW was competitively procured. Payment for this project would be made on a levelized monthly basis. Since this project would consist of 500kV facilities, this resulting annual payment would be added to the bulk system annual revenue requirement. The recommended combined functionalization after accounting for RGUCC and FMW is presented in Table D-5 below. This shows a somewhat higher proportion functionalized as regional and POD, compared to the Commission approved functionalization filed in the 2014 ISO Tariff Application (bulk: 59.2%, regional: 21.6%, POD: 19.2%). This is sensible since capital additions to regional and POD functions outweigh capital additions to bulk function after 2016, and some bulk system projects included in the 2014 Study were later deferred or cancelled.

Table D-5 - Final O&M and capital cost functionalization

Function / Year	2018	2019	2020
Bulk	51.4%	52.8%	51.7%
Regional	25.8%	24.5%	24.6%
POD	22.8%	22.7%	23.7%

The AESO updated classification using all available transmission line data but concluded that outcome was unreasonable. This is further discussed in section D-8 of this 2018 Update. The AESO has continued the use of the Commission approved 138/144kV line, 240kV line, 500kV line and substation classification in the update for 2018-2020. The resulting bulk and regional classification is presented in Table D-6 below.

Table D-6 - Bulk and regional classification

Class	Bulk	Regional
Demand Related Costs	93.4%	89.5%
Energy Related Costs	6.6%	10.5%

Finally, like LEI, the AESO has made three observations with regards to implementation of recommended functionalization and classification results. First, as presented in Table D-7 and Table D-8, by using the functionalization and classification results discussed above, the revenue requirement across each of the rate components (bulk-demand, bulk-energy, regional-demand, regional-energy and POD) increases on an annual basis, indicating no reversing trends that can result in erratic pricing signals.

Table D-7 - Revenue requirement breakdown by function

Revenue Requirement by Function			
Revenue Requirement Split ($ million)	**2018**	**2019**	**2020**
Bulk	1,035	1,191	1,301
Regional	519	553	619
POD	460	513	597
Total	2,013	2,258	2,516

Table D-8 - Revenue requirement breakdown by function and by class

Revenue Requirement by Function by Class			
Revenue Requirement Split ($ million)	**2018**	**2019**	**2020**
Bulk – Demand	967	1,113	1,215
Bulk – Energy	68	78	85
Regional – Demand	464	495	554
Regional – Energy	54	58	65
POD	460	513	597
Total	2,013	2,258	2,516

Second, the impact of applying final capital and O&M cost functionalization results instead of applying only capital cost functionalization results (as presented in Table D-7 and Table D-9) is not in opposing directions, i.e., revenue requirement trend remains positive and increasing across all rate components. For consistency with cost causation, like LEI, the AESO recommends applying final capital and O&M functionalization results.

Table D-9 - Revenue requirement breakdown using capital cost functionalization only

Revenue Requirement by Function			
Revenue Requirement Split ($ million)	**2018**	**2019**	**2020**
Bulk	1,152	1,314	1,434
Regional	475	508	570
POD	386	436	512
Total	2,013	2,258	2,516

Third, for consistency with cost causation, the AESO proposes to apply separate 2018, 2019 and 2020 functionalization results (as presented in Table D-5 above) for each of the three years.

D-2 Consultation

The AESO consulted with stakeholders between August 2015 and June 2017 to solicit input and feedback on AESO's approach to proceed with 2018 Update, functionalization results, classification results and proposed classification. A summary of the stakeholder consultation pertaining to the 2018 Update is presented in table below and included fully in Appendix C of this application.

Stakeholder Session	Topic	Summary
August 18, 2015	2017 (subsequently revised to 2018) ISO tariff application scope	Proposed to update the 2014 Study Presented process and probable timeline
January 30, 2017	Share information on 2018 ISO tariff application work	Presented preliminary capital, O&M, combined, and final functionalization results
April 10, 2017	Share information on 2018 ISO tariff application work	Provided information on future regional system asset additions Presented preliminary bulk system and regional system classification
June 26, 2017	2018 ISO tariff application preview	Presented up to date preliminary capital, O&M, combined, and final functionalization results Proposed to continue the 2014 Study bulk system and regional system classification for 2018 to 2020

D-3 Scope and information utilized

The LEI was engaged to prepare the 2014 Study for the AESO. The 2014 Study was filed on July 17, 2013 as part of the 2014 ISO Tariff Application. An update was filed on November 11, 2013 as part of a negotiated settlement agreement. And finally an update was filed on January 21, 2014 pursuant to negotiated settlement agreement. This 2018 Update, which is a straight forward update of the abovementioned 2014 Study, is being filed with this 2018 ISO Tariff Application ("Application") as Appendix D and underlying workbook as Appendix E to this Application. Accordingly unless explicitly stated this 2018 Update utilizes exactly the same data sources, methodologies and calculations as the 2014 Study. Any discussion of data sources, methodologies and calculations is for ease of understanding and reference only.

D-3.1 Scope

Like the 2014 Study, scope of this 2018 Update includes the following key areas:

1. **Functionalization of capital costs**: The 2018 Update provides results for functionalization of TFO capital-related costs into bulk, regional and POD functions. The results take into account both existing (end of 2014) and future (2015 to 2020) transmission facilities that will give rise to capital-related costs up until 2020.

2. **Functionalization of O&M costs:** The 2018 Update provides results for the functionalization of TFO O&M costs into bulk system, regional system and POD functions.

3. **Classification of bulk system and regional system costs**: Following functionalization of capital and O&M costs, the 2018 Update provides results for the classification of bulk system and regional system costs into demand-related and energy-related costs. Classification of POD costs is not in the scope of the 2018 Update. POD costs are being classified as part of POD cost function analysis being filed with the Application as Appendix F.

4. **Implementation considerations:** Finally, the 2018 Update discusses the potential impact of implementing recommended functionalization and classification results on rates and breakdown of revenue requirement to be recovered.

As was done in the 2014 Study, this 2018 Update first functionalizes capital cost, then functionalizes O&M cost, then combines capital cost and O&M cost functionalization using ratio of capital cost to non-capital cost, and then finally incorporates RGUCC and FMW charge to calculate final functionalization.

This 2018 Update calculates bulk and regional classification using all available transmission line data but the AESO concluded that outcome was unreasonable. This is further discussed in section 8 of this 2018 Update. The AESO has continued the use of the Commission-approved 138/144kV line, 240kV line, 500kV line and substation classification in the 2014 Study, for 2018-2020.

The 2018 Update, like the 2014 Study, does not consider rate design issues. Rate design is being addressed in section 5 of the Application.

D-3.2 Data utilized and limitations

The AESO used internal databases, tools and resources such as Transmission Administration System Model ("TASMo"), Transmission Settlement System ("TSS"), Long-term Transmission Plan ("LTP"), Cost Benchmark database and Google Earth plugin. The AESO requested, received and utilized external data such as TFO switching maps, existing asset details, and operating and maintenance cost details.

Existing asset information was requested and received towards end of 2015. This existing asset information was as of end of 2014 ("existing asset"). All line and substation level details were not available for ATCO, ENMAX and EPCOR. A full discussion of existing asset information is found in section 6.1.2 of this appendix.

For future i.e. planned projects, data from Cost Benchmark database was supplemented with internal planning, Need Identification Document ("NID") and Facilities Application ("FA") type data. For the purpose of this 2018 Update future asset include all assets with in-service date from 2015 to 2020 ("future asset").

Finally respecting materiality, cost data for all lines and substations with original cost of over $100 million was updated towards end of May 2017.

D-3.3 Summary of data used

The following is a high level summary of where data was sourced and how it was used in the analysis:

D-3.3.1 Capital data

1. Existing assets: line and substation asset net book values provided by TFOs.
2. Future assets: sourced from Long-term Transmission Plan, TFO regulatory filings such as general tariff applications (GTAs), Cost Benchmark database, NIDs and FAs.
3. Projected ongoing connection and capital maintenance costs.

D-3.3.2 O&M data

Revenue requirement and operating cost data included in the TFOs GTAs, up until 2017 for all four TFOs, supplemented with additional information provided by the TFOs upon AESO's request.

Capital and O&M functionalization results for each of the years, 2018-2020, are weighted based on capital to non-capital cost ratio. This ratio have been extrapolated from capital to non-capital cost trend.

D-3.3.3 Classification data

1. 138 kV and 240 kV line costs from 2005 to 2017 from Cost Benchmark database and substation costs from the 2014 Study, and
2. 500 kV conductor costs from the 2014 Study which were sourced from California Independent System Operator ("ISO").

D-4 2014 Study, Negotiated Settlement and Commission Decision

This section briefly summarizes the key area of discussion in 2014 Study and potential implications for this 2018 Update.

In 2010 Interveners noted that there is likely to be a significant increase in the proportion of bulk transmission facilities built for reasons other than providing reliable delivery at times of peak load and, as a result, there is a strong possibility that the classification of bulk transmission facilities will change to a more energy-intensive classification. In the 2014 Study, LEI divided planned system additions between conventional and special planned projects, whereby special projects are those that are primarily designed for purposes other than meeting peak load needs. Negotiated Settlement Agreement stated:

> *"The Parties agree that the following are excluded from this Settlement Agreement:*
>
> *(a) matters related to the point of delivery cost function;*
>
> *(b) matters related to rate design; and*
>
> *(c) cost recovery for special projects, whether as contemplated in the 2014-2016 Cost Causation 2014 Study or as proposed on some other basis by a participant in Proceeding ID No. 2718."*

In Decision 2014-242 on August 21, 2014, the Commission stated:

> *"The Commission considers the types of projects the UCA would propose to classify as special have the same cost causation drivers as historical projects. The Commission also accepts the arguments of the ADC that the determination of projects as special and how that status may change over time could be contentious. For the above reasons, the proposal of the UCA to classify projects as special is rejected."*

The AESO has therefore not classified any projects as special and has not proposed any special cost recovery for special projects.

D-5 Definition of transmission functions

The process of functionalization allocates costs into three functional groups: *bulk*, *regional* and *POD*. These three functions do not have universally accepted definitions. The AESO has defined these as per 2014 Study.

Traditionally, large-scale generators produce electricity, which is transferred by the bulk, high voltage system over long distances to reach regional systems, and eventually to reach loads at POD. The bulk system is defined as high voltage, which typically carries large amounts of electricity over long distances. Bulk transmission lines provide high capacity pathways between geographically separated concentrated load centers such as Edmonton and Calgary. Bulk transmission lines provide high capacity interconnections between adjacent utilities such as those in British Columbia or Saskatchewan. These bulk transmission lines typically operate at 500 kV and 240 kV of alternating current ("AC") or as high voltage direct current ("HVDC"). Point-of-supply ("POS") substations that connect generation to the transmission system are also considered bulk. Supply related costs at POS are fully offset by upfront cash contribution from generation market participant.

The system which transmits electricity from the bulk system to load centers with numerous PODs is known as regional. Regional transmission lines are typically lower in capacity and shorter in length than bulk transmission lines. Regional transmission lines typically operate at 138/144 kV and 69/72 kV.

The point of delivery system serves distribution utilities or industrial customers that connect directly to the transmission system. The POD function is easiest to identify as substations serving end use load(s), radial transmission lines which serve these substations, or radial transmission lines directly serving end use load are considered POD. Demand related costs at POD in excess of maximum investment are offset by upfront cash contribution from load market participant.

The RGUCC arises from TFO-owned facilities providing system access to previously regulated generators. Since generation related costs and revenues are assigned to bulk function, the RGUCC annual revenue is deducted from the bulk system annual revenue requirement.

FMW was competitively procured. Payment for this project would be made on a levelized monthly basis. Since this project would consist of 500kV facilities, this resulting annual payment is added to the bulk system annual revenue requirement.

D-6 Functionalization of capital costs

Like the 2014 Study, this 2018 Update uses functionalization by voltage method.

D-6.1 TFO cost data

The following section specifies data sources used in the capital cost functionalization analysis, and describes the data utilization approach. This section also specifies data limitations and any assumptions. Data sources, utilization approach, limitation and assumptions remain same as in 2014 Study.

D-6.1.1 Depreciation

All net book values were depreciated to respective test year prior to functionalization. TFO GTA schedules were utilized to determine depreciation rates for AltaLink and ATCO. EPCOR depreciation rates were determined using GTA schedule supplemented by a confidential data request. ENMAX depreciation rates were determined using a confidential data request.

Table D-10 - Transmission Line Depreciation Rate by TFO

TFO / Year	2017-2020
Altalink	3.07%
EPCOR	2.31%
ENMAX	2.70%
ATCO	2.40%

Table D-11 - Transmission Substation Depreciation Rate by TFO

TFO / Year	2017-2020
Altalink	3.34%
EPCOR	4.11%
ENMAX	2.79%
ATCO	2.44%

For AltaLink lines, an asset-weighted average of land rights, towers and fixtures, overhead conductors and poles and fixtures was used. For AltaLink substations, an asset-weighted average of land rights, station equipment and system communication and control was used.

For ATCO lines, an asset-weighted average of total land rights, towers and fixtures, overhead conductor towers, poles and fixtures, and overhead conductor poles was used. For ATCO substations, an asset-weighted average of land rights, and substation equipment was used.

The ENMAX depreciation data was not found in its tariff application. The AESO requested depreciation information from ENMAX and then used an asset-weighted average of wood poles, steel towers, steel poles, insulators, overhead conductor, underground conductor, manholes, underground cable LPOF, underground cable HPOF and underground cable solid dielectric costs to calculate line depreciation rate. The AESO used an asset-weighted average of substation equipment, tele-control, supervisory and land rights costs to calculate substation depreciation rate.

For EPCOR depreciation data from its tariff application along with account balances provided upon the AESO's request were used to calculate asset-weighted average of land rights, towers and fixtures, poles and fixtures, overhead conductor and devices, and underground conductor and devices costs to calculate line depreciate rate. The AESO used an asset-weighted average of station equipment and system communication and control costs to calculate substation depreciation rate.

Given 2018 to 2020 depreciation forecasts were not available through the tariff applications in middle of 2016 when this 2018 Update was prepared, and depreciation rates were seen not to vary significantly from year to year, each TFO's latest known depreciation rate was used for 2018 to 2020.

D-6.1.2 Existing asset data

The AESO requested and received asset data from all four TFOs with various levels of detail. The AESO required line and substation-level details on net book values and voltages to perform functionalization.

AltaLink provided existing asset data with the necessary detail to perform functionalization by voltage.

ATCO provided voltages for most lines and substations, however net book values for individual assets is not available. ATCO provided total accumulated depreciation for all assets and same as in the 2014 Study the AESO proportioned it to each asset using asset cost and years of service.

ENMAX provided data aggregated to the level of total substation and total transmission, which were assumed to be completely functionalized as POD and regional, respectively as in the 2014 Study. 95% of ENMAX substations are POD and over 97% of ENMAX lines are of 138 kV or 69 kV voltage which are functionalized as regional under functionalization by voltage approach.

EPCOR provided total installed assets under three categories: Genesee Switchyard, total transmission, and total substations, which were functionalized as bulk, regional, and POD respectively as in the 2014 Study.

Ongoing capital maintenance for existing projects is assumed to be about $276 million per year (sourced from TFO GTAs). The POD connection projects are assumed to be 60% of about $162 million per year (sourced from the AESO POD costs database) starting from 2017. The value of 60% represents overall average investment level while remaining 40% of POD costs are offset by cash contributions from load market participants. The value of about $162 million per year represents simple average of POD costs from 2007 to 2016 in POD costs database.

The sources, assumptions and calculations are same as in the 2014 Study.

Table D-12 - Existing asset (at end of 2014) net book values depreciated to 2020

	2020 dollars	% share
AltaLink Lines	$1,772,609,378	26%
AltaLink Substations	$1,587,322,844	23%
ATCO Lines	$1,644,709,158	24%
ATCO Substations	$1,198,448,601	18%
ENMAX	$223,368,930	3%
EPCOR	$334,882,598	5%

D-6.1.3 Future Assets

In Decision 2010-606, the Commission instructed the AESO to consider a forecast of capital build for the entire expected effective term of the AESO's next tariff, using the LTP as a starting point. The 2015 LTP includes a forecast of capital build which was updated as part of Transmission Rate Projection (TRP) publication in December 2016 and as part of this application in May 2017.

The AESO Cost Benchmark database was the primary source of future asset data. The AESO Cost Benchmark database contains manually extracted information from Proposal to Provide Services documents, which are usually included with NIDs and/or FAs. The cost information is subject to wide confidence intervals. NID type cost estimate are of a +30%/-30% quality, while FA type cost estimates are of a +20%/-10% or better quality. The asset in-service year generally does not change as capital project progresses from inception to completion. However change in in-service date can have a material impact similar to change in cost. This database is estimated to include almost all projects put into service post 2014.

To supplement and validate information from the database, the AESO reviewed final cost reports, individual project progress reports that are submitted to the Transmission Facility Cost Monitoring Committee ("TFCMC"), and NID applications. The AESO Cost Benchmark database may not contain the latest cost information in all cases. The AESO manually updated cost information to the latest value for all lines and substations costing over $100 million in May 2017.

D-6.2 Functionalization

Functionalization by voltage uses voltage levels of lines and substations to categorize costs. Same as in the 2014 Study, for lines, firstly radial lines serving a single point of delivery are considered POD, and radial lines serving a generator are POS, and considered bulk. Then, all remaining lines with voltages 240 kV and higher are functionalized as bulk. Finally, all remaining 138/144 kV and 69/72 kV lines are considered regional. This method of functionalization by voltage was applied to both existing assets and future assets.

Although substations operate at both a high and low voltage level, for the purposes of functionalization by voltage, same as in the 2014 Study, the AESO functionalized whole substations based on secondary voltages, where data was available. Substations with a secondary voltage of:

1. 240 kV or higher are considered bulk
2. 138/144 kV or 69 kV are considered regional, and
3. 25 kV or lower are considered POD.

All future substations were also functionalized in this manner.

As in the 2014 Study, existing substations are also functionalized using the AESO TSS database, which identifies the contracted capacity for Rate DTS, *Demand Transmission Service*, and Rate STS, *Supply Transmission Service*. Substations with only Rate DTS contracts are functionalized as POD, while substations with only Rate STS contracts are considered point-of-supply ("POS") and thus functionalized as bulk. Finally, substations with both Rate DTS and Rate STS contracts are allocated to POD and bulk, respectively, allocated by their contract capacity. As discussed in section 5, load construction contributions offset costs functionalized as POD and supply construction contributions fully offset costs functionalized as POS.

D-6.2.1 Functionalization results

The results below show functionalization by voltage for existing assets, future assets, and the net book value weighted overall functionalization results. These results do not include the impact of RGUCC or FMW.

Table D-13 - Existing asset functionalization results, as of December 2020

TFO	Bulk System	Regional System	POD
AltaLink	49.7%	23.9%	26.4%
Atco Electric	37.2%	41.7%	21.2%
ENMAX	0.0%	37.2%	62.8%
EPCOR	76.9%	5.5%	17.5%
All TFOs %	**40.3%**	**28.6%**	**31.2%**
All TFOs $	$3,485,409,040	$2,470,560,565	$2,697,038,561

Table D-14 - Future Asset functionalization results, as of December 2020

TFO	Bulk System	Regional System	POD
All TFOs %	71.9%	18.0%	10.1%
All TFOs $	$5,631,660,460	$1,413,460,754	$790,729,583

Table D-15 - Existing and future asset functionalization results, depreciated to 2020

TFO	Bulk System	Regional System	POD
All TFOs %	55.3%	23.6%	21.%
All TFOs $	$9,117,069,499	$3,884,021,319	$3,487,768,143

D-6.2.2 Comparison to functionalization results from the 2014 Study

The functionalization results from the 2014 Study are presented in Table D-16 below. This 2018 Update shows a modest increase in bulk function amount and significant increase in both regional and POD function amounts compared to the results from the 2014 Study. This reflects relatively small asset additions to bulk function and sustained moderate asset additions to regional and POD functions, and that some future bulk system projects included in the 2014 Study were later deferred or cancelled. Note that RGUCC revenues and FMW costs are not included in tables in this section. These FMW costs and RGUCC revenues are discussed in section 10.

Table D-16 - Existing and future asset functionlization results from the 2014 Study, depreciated to 2020

TFO	Bulk System	Regional System	POD
All TFOs	66.9%	18.1%	15.0%
All TFOs	$8,744,120,987	$2,361,392,794	$1,964,692,868

D-7 Functionalization of O&M costs

D-7.1 TFO cost information

The information utilized for functionalization of O&M costs was primarily obtained from the TFO GTAs and other TFO filings with the Commission. This information was collected from the four largest TFOs: ATCO, AltaLink, ENMAX and EPCOR. Addition specific data was requested and received from the TFOs to fill the gaps as required.

The 2014 Study added O&M data from 2010 to 2014. The AESO has now added 2015 to 2017 data in this 2018 Update.

D-7.2 Breakdown of revenue requirement

The first step was to identify costs that are capital-related and non-capital related. This 2018 Update follows the 2014 Study which determined that:

1. Capital costs include depreciation, return and income tax associated with TFO assets, annual structure payments, linear and property taxes, and capital-related revenue offsets, and
2. Non-capital costs include O&M costs directly associated with the electric transmission system such as labor costs, G&A costs associated with the operation the overall business of the TFOs, fuel and variable O&M costs associated with isolated generation serving remote communities and affiliate revenue offsets, i.e., revenues that offset labor costs.

As in the 2014 Study, all operating and G&A costs included in non-capital costs are net of capitalized labor and other capitalized costs. This treatment is consistent with the capitalization policies of the TFOs.

Table D-17 and Table D-18 present the breakdown of non-capital costs by TFOs, and as a percentage of total revenue requirements for the four largest TFOs. Since 2010, although the amount of non-capital costs has been increasing, the percentage of non-capital costs has been gradually declining steadily until 2015, reducing projected overall share of non-capital costs from 26.4% in 2010 to 17.4% in 2015. From 2015 to 2017 share of non-capital cost has levelled off.

Table D-17 - TFO non-capital costs

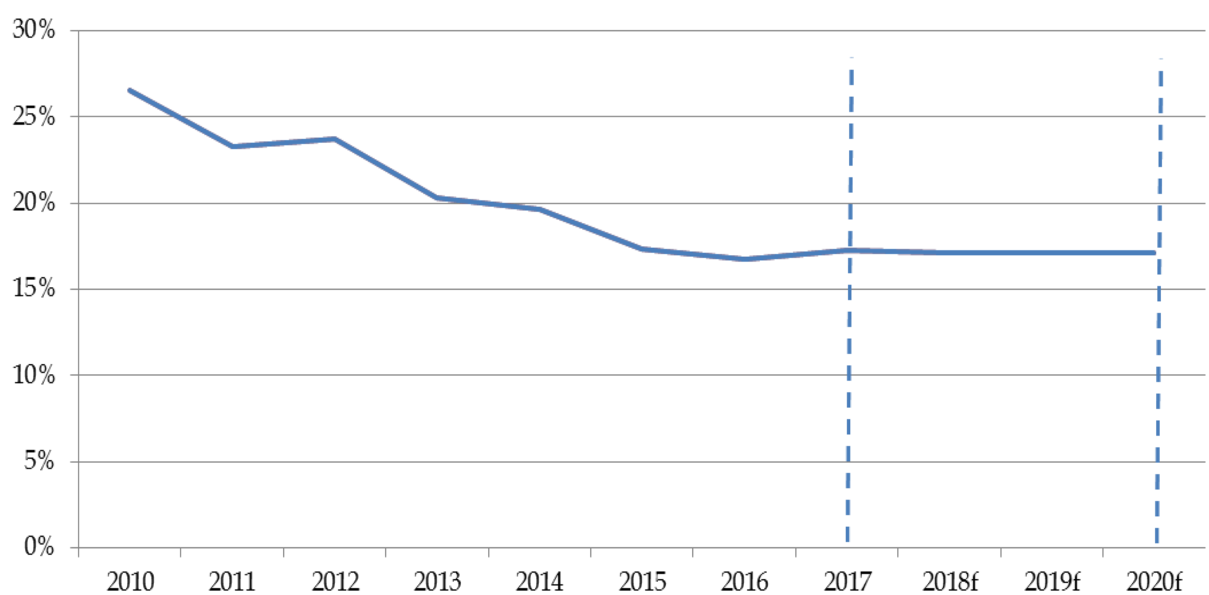
TFO/ Year	2010	2011	2012	2013	2014	2015	2016	2017
AltaLink	63,296,013	61,651,319	80,562,573	88,488,133	106,294,967	99,376,336	110,225,805	119,961,187
ATCO	61,962,863	72,583,190	82,057,090	80,655,881	82,242,393	120,992,720	142,415,701	153,608,894
ENMAX	20,881,000	23,344,656	27,752,369	32,868,000	36,417,000	38,908,000	34,963,000	38,041,000
EPCOR	18,073,084	19,055,546	20,716,560	22,545,570	23,710,048	24,706,244	24,725,519	25,785,847
TOTAL	**164,212,960**	**176,634,711**	**211,088,592**	**224,557,584**	**248,664,408**	**283,983,300**	**312,330,025**	**337,396,928**

Table D-18 - TFO non-capital costs as a % of revenue requirement

TFO/ Year	2010	2011	2012	2013	2014	2015	2016	2017
AltaLink	22.3%	17.5%	21.3%	17.9%	19.6%	13.3%	13.0%	13.5%
ATCO	25.4%	23.2%	20.4%	16.6%	14.6%	16.8%	16.8%	17.4%
ENMAX	55.1%	57.5%	65.7%	60.0%	55.8%	52.6%	46.5%	46.5%
EPCOR	32.8%	32.5%	31.7%	31.8%	25.1%	26.3%	24.8%	26.2%
Average	**26.4%**	**23.1%**	**23.8%**	**20.31%**	**19.6%**	**17.4%**	**16.7%**	**17.3%**

Given the relatively limited transmission capital investment plan in the 2017-2020 timeframe, it can be reasonably argued that share of non-capital cost has stabilized and should remain around this level in the near term. The AESO has accordingly used 2015-2017 non-capital cost share's simple average of 17.1% for 2018, 2019 and 2020. The 2014 Study used the trend from 2010 to 2014 to forecast non-capital cost share for 2015 and 2016. This 2018 Update follows similar logic in using the trend from 2015 to 2017.

Figure D-19 - TFO non-capital cost share - trend and projection



D-7.3 O&M functionalization

Similar to capital cost functionalization, O&M costs have been functionalized into three functional categories: bulk system, regional system and POD.

As in the 2014 Study, not all non-capital costs have been functionalized. G&A costs, which are not directly associated with the operations of electric transmission system, but assist in overall operation of the business, such as expenses associated with maintenance of corporate head office, have not been functionalized. Instead O&M functionalization results have been applied to these costs. A portion of G&A costs is allocated to capital projects as part of the distributed costs. The remaining G&A costs are related to non-capital activities and are wholly considered O&M. G&A costs sourced from GTAs belong to non-capital category.

As in the 2014 Study, functionalization of other non-capital costs (other than non-capital G&A costs) is as follows. Fuel costs and variable O&M costs associated with isolated generation have been functionalized as regional or POD because any transmission system otherwise built to serve these small remote areas would likely be regional or POD. This allocation between regional and POD is based on results of overall capital cost functionalization ratio of regional to POD.

As in the 2014 Study, other O&M costs were allocated to functions on their individual basis of cost causation, where appropriate. For example net salaries and wages have been allocated to various groups (such as control center operations, station equipment maintenance, overhead line expenses etc.) using proportion of full time equivalents ("FTE") in each group, where provided, and further allocated between bulk, regional and POD using allocators discussed below.

- costs associated with control center operations have been allocated based on combined number of lines and number of transformers split between bulk system, regional system, and point of delivery,
- vegetation management expenses have been allocated based on a line brushing allocator, estimated using square kilometers of relevant vegetation management area split between bulk, regional and POD. The split is estimated by multiplying line length by voltage within bulk, regional and POD function by width of the right of way for brushing,
- substation expenses have been allocated based on number of transformers split between bulk, regional and POD functions.
- overhead line expenses and miscellaneous transmission expenses have been allocated based on kilometres of line split between bulk, regional, and POD functions.

Information for all four TFOs up until 2017 was used to functionalize their O&M costs for the respective years. The O&M functionalization results for the TFOs are presented in Table D-20 below.

Table D-20 - TFOs O&M Functionalization results

Function	2014	2015	2016	2017
Bulk	37,017,688	42,732,802	48,182,282	50,641,966
Regional	63,785,774	71,141,759	78,608,951	82,393,047
POD	73,905,750	70,786,807	82,805,976	87,819,174
Total	**174,709,212**	**184,661,368**	**209,597,209**	**220,854,187**

This 2018 Update is to provide O&M costs functionalization for 2018-2020. In middle of 2016 when this 2018 Update was prepared, TFO O&M costs details for 2018-2020 were not available. Figure D-21 below shows a decreasing trend in bulk and regional functionalization, and increasing trend in POD functionalization from 2015 to 2017. The AESO therefore used this trend from 2015 to 2017 to forecast O&M costs functionalization for 2018-2020 presented below in Table D-22. The 2014 Study used 2014 O&M cost functionalization for 2015 and 2016.

Figure D-21 - TFO O&M functionalization 2010-2017

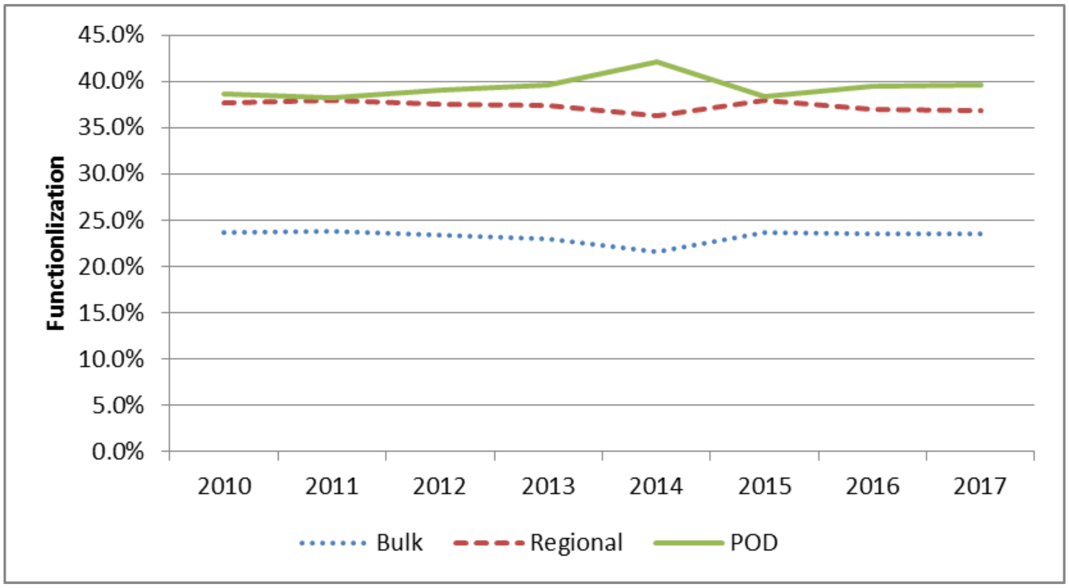


Table D-22 - TFO O&M functionalization 2015-2020

Function / Year	2015	2016	2017	2018f	2019f	2020f
Bulk	23.7%	23.6%	23.5%	23.4%	23.2%	23.1%
Regional	37.9%	37.0%	36.9%	36.3%	35.7%	35.2%
POD	38.4%	39.4%	39.6%	40.4%	41.0%	41.6%

D-8 Combined O&M and capital cost functionalization

D-8.1 Combined functionalization results

As in the 2014 Study, capital costs and O&M costs functionalization results were combined using TFOs capital costs to non-capital costs ratio presented in Table D-22 below.

Table D-22 - Combined O&M and capital cost functionalization

Function / Year	2018	2019	2020
Bulk	51.5%	50.7%	49.8%
Regional	25.7%	25.6%	25.6%
POD	22.8%	23.7%	24.7%

D-8.2 Final functionalization results

For the 2018-2020 period, the AESO's wires related revenue requirement would include two components which are not accounted for in TFO capital costs or TFO non-capital costs. These two components are RGUCC which is a revenue and payments for FMW charge which is a cost.

D-8.2.1 Regulated Generating Unit Connection Charge (RGUCC)

RGUCC recovers an annual revenue amount. RGUCC arises from TFO-owned facilities providing system access to previously regulated generators. It is not related to specific transmission assets. This annual revenue amount is deducted from the bulk system annual revenue requirement since generation related costs and revenues are assigned to bulk function. RGUCC gradually declines over time and expires in 2020. RGUCC annual amount is $4.4 million, $2.6 million, and $0.9 million for 2018, 2019, and 2020 respectively.

D-8.2.2 FMW Costs

FMW was competitively procured. Payment for this project would be made on a levelized monthly basis. Since this project would consist of 500 kV facilities, this resulting annual payment is added to the bulk system annual revenue requirement. Please see tab Rates of Appendix J for annual payment amount calculation.

Table D-23 - Accounting for RGUCC and FMW in combined O&M and capital cost functionalization - 2020 example

	Bulk	Regional	POD	Total
Before RGUCC revenue and FMW cost (%)	49.8%	25.6%	24.7%	100%
Before RGUCC revenue and FMW cost ($ millions)	1,205	619	597	$2,420
Deduct RGUCC revenue ($ millions)	(1)	-	-	(1)
Add FMW cost ($ millions)	96	-	-	96
After RGUCC revenue and FMW Cost ($ millions)	1,301	619	597	2,516
After RGUCC revenue and FMW Cost (%)	51.7%	24.6%	23.7%	100%

Table D-23 represents the final recommended functionalization, including capital, O&M, RGUCC and FMW costs for 2018, 2019 and 2020.

D-8.2 Analysis of functionalization results

The final functionalization results show a lower proportion functionalized as bulk, as compared to the Commission approved functionalization in AESO 2014 ISO Tariff Application from the 2014 Study, presented in Table D-24. This is sensible given the capital additions since 2016 have mostly been regional and POD, and some future bulk system projects included in the 2014 Study were later deferred or cancelled.

Table D-24 - AESO 2014 GTA functionalization

Function / Year	2014	2015	2016
Bulk	52.8%	58.2%	59.2%
Regional	24.4%	22.3%	21.6%
POD	22.8%	19.5%	19.2%

Table D-25 shows that since 2016 vast majority of capital investment has been in regional and POD functions. Between 2016 and 2020, bulk system capital costs do not change materially while regional system capital costs are forecasted to increase by about $0.8 billion and POD capital costs are forecast to increase by about $0.9 billion. Table D-25 does not include impact of RGUCC and of FMW charge. FMW project in expected to be in service in 2019 and thus FMW charge will increase bulk system revenue requirement starting in 2019.

Table D-25 - Capital costs functionalized ($ millions)

	2016	2017	2018	2019	2020	Increase from 2016 to 2020
Bulk	9,146	9,240	9,245	9,251	9,117	(29)
Regional	3,065	3,795	3,794	3,849	3,884	819
POD	2,598	2,938	3,088	3,303	3,488	890
Total	**14,808**	**15,973**	**16,128**	**16,404**	**16,489**	**1,680**

D-9 Classification of bulk and regional costs

Classification separates costs for each function into demand related or energy related or customer related. The 2014 Study minimum system approach adapted for transmission system uses the ratio between a minimum system and an optimized system to determine the demand related component. Remaining costs are allocated to energy.

As in the 2014 Study, for 2018 Update the classification was first determined for minimum and optimum system for 500 kV lines, 240 kV lines, 138/144 kV lines and a sample substation. The bulk classification was determined by weighting 500 kV, 240 kV and sample substation classifications together, using their respective 2020 asset costs. The regional classification was determined by weighting 138/144 kV and sample substation classifications together, using their respective 2020 asset costs.

D-9.1 Conductor classification

Minimum system approach requires identifying a minimum line and an optimized line. In the 2014 Study the LEI defined "minimum" and "optimal" conductor sizes as comparable lines that TFOs would consider, where the optimized line minimizes losses over the minimum line.

As in the 2014 Study, for this 2018 Update cost information for various conductor sizes was sourced from the AESO Cost Benchmark database. The Cost Benchmark data was filtered for new projects with no missing conductor size or voltage data. From this filtered data set, line costs per kilometer were calculated for the minimum and commonly used conductor sizes using a length-weighted average since longer conductors are assumed to provide more indicative results. As well, the filtered data set contained double circuit, single circuit, and double circuit with one circuit installed line types. Costs for different line types were normalized using adjustment factors in the 2014 Study to make them comparable.

D-9.1.1 Bulk system conductor classification

For bulk classification in the 2014 Study, the LEI determined minimum and optimized system for 240 kV and 500 kV lines separately, and then calculated a combined classification using their relative costs as weights to arrive at a bulk classification. In the 2014 Study, the LEI determined that the two most commonly constructed 240 kV conductor sizes in Alberta are 2x795 and 2x1033 thousand circular mils ("MCM") aluminum conductor steel reinforced ("ACSR"). These two conductor sizes could be compared by a TFO designing a 240 kV line, where the 2x795 MCM ACSR conductor is the less expensive "minimum" option, and the 2x1033 MCM ACSR conductor is the more expensive but minimizes losses, as the "optimized" option. Costs were normalized using adjustment factors in the 2014 Study to a double circuit line strung both sides, which is a common configuration in Alberta. The AESO has mechanically updated the same calculation using data available to date and the results are presented below in Table D-26. This update results in 240 kV line classification of 65.2% demand to 34.8% energy.

Table D-26 - 240 kV - minimum and optimal conductor size line costs

System	Conductor Size	Cost of Conductor ($/km)
Minimum System	240 kV Line - 2 X 795	1,341,544
Optimal System	240 kV Line - 2 x 1033	2,057,307

For 500kV the 2014 Study defined minimum as 2x2156 MCM ACSR conductor with a cost of $1.9 million per km, and optimal as 3x1590 MCM ACSR conductor with a cost of $2.1 million per km. This results in

500 kV line classification results of 90.5% demand to 9.5% energy. The AESO has continued to use of these results for 500kV lines from the 2014 Study.

The bulk classification was determined by weighting 500 kV and 240 kV classifications together, using their respective 2020 line asset costs. The bulk conductor classification results in a ratio of 76.1% demand to 23.9% energy.

D-9.1.2 Regional system conductor classification

The 2014 Study calculated regional classification by determining minimum and optimized system for a 138 kV or 144 kV line. The 2014 Study concluded that for the regional system two most commonly constructed conductor sizes are 266 and 477 MCM ACSR. These two conductor sizes could be compared by a TFO designing a 138 kV or 144 kV line, where the 266 MCM conductor is the less expensive “minimum” option, and the 477 MCM conductor id the more expensive “optimized” option that minimizes losses. Costs were normalized using adjustment factors in the 2014 Study to single circuit lines in order for them to be comparable. The AESO has mechanically updated the same calculation using data available to date. The regional conductor classification results in a ratio of 93.9% demand to 6.1% energy.

Table D-27 - Regional - minimum and optimal conductor size line costs

System	Conductor Size	Cost of Conductor ($/km)
Minimum System	138 kV Line - 266	529,856
Optimal Lines	138 kV Line - 477	564,417

D-9.2 Substation classification

The 2014 Study defined the optimized substation as one which minimizes losses over a minimum substation. The 2014 Study used a quote for a POD transformer which included both a “Standard Losses and Sound Level” transformer, which was considered a minimum system, and a “Lower NLL & Sound Level” transformer, which given its lower loss characteristic, was considered the optimal system.

These quotes indicated that the "minimum system" POD transformer is approximately 2.8% cheaper than an "optimal system" POD transformer. It was assumed that regional and bulk power transformers would also have a similar percentage cost increase in material and manufacturing costs for an "optimal system" transformer. Consequently, this percentage cost increase was also applied to regional and bulk power transformers. The 2018 Update has continued to use of these substation results from the 2014 Study.

Table D-28 - Substation classification results

Substation classification	
Demand Related Costs	97.2%
Energy Related Costs	2.8%

D-9.3 Classification results

To obtain the combined (line and substation) bulk and regional classification results, the line classification results were weighted with substation classification results using line and substation asset values. Table D-29 shows classification results for both bulk and regional systems.

Table D-29. Classification results by functional group

	Bulk	Regional
Demand Related Costs	81.1%	95.5%
Energy Related Costs	18.9%	4.5%

D-9.4 Proposed Classification

The AESO notes that classification results of this 2018 Update, which is a mechanical update of the 2014 Study, are significantly different than the Commission approved classification results of the 2014 Study for the 2014 ISO tariff presented in Table D-30 below.

Table D-30 - 2014 ISO tariff classification results by functional group

	Bulk	Regional
Demand Related Costs	93.1%	87.4%
Energy Related Costs	6.9%	12.6%

D-9.4.1 Drivers of change in classification results

The AESO compared line data included in the 2014 Study and this 2018 Update to determine the cause of this significant difference. The AESO notes that cost increased for the lines with optimal conductor much more than for lines with minimum conductor, both in terms of count and amount, as the transmission capital projects progressed towards completion. Other line data such as line type (single circuit, double circuit, double circuit one side strung) and line length rarely changed with project progression. Please see tab “StudytoUpdateComparison” of workbook Appendix E. This means ratio of cost of lines with optimal conductor to cost of lines with minimum conductor is higher in this 2018 Update. Such higher ratio means a higher energy classification.

D-9.4.2 Observations on classification calculations

The 2014 Study concluded that minimum system costs are driven by serving total load and therefore are classified as demand related. Additional costs of optimal system are driven by energy usage considerations and therefore are classified as energy related.

In AESO’s experience additional costs of optimal system are driven mostly by additional capacity requirement and standardization for more efficient and economic planning, engineering, building, operating, maintaining and replacing, rather than by energy usage or energy losses considerations. It is uncommon for a TFO to find optimal line more economic than minimum line in a line optimization study on the basis of energy losses savings alone.

The 2014 Study calculated classification as ratio of cost of two most common conductors used in Alberta for a given voltage. The 2014 Study calculated cost as length weighted average (sum of cost divided by sum of length) using NID and FA type line data provided from the AESO Cost Benchmarking database. NID and PPS type data has different confidence intervals of +30% to -30% and +20% to -10% respectively and perhaps should not be grouped together. More importantly NID and FA type data is quite varied and volatile on a per kilometer basis for a number of reasons. Some of these factors can have differentiated impact on different types of lines or on lines with different conductors. Any ratio based on this data is expected to be volatile and this is indeed the outcome as the AESO noted above. Classification is a price signal which should be stable and predictable, not volatile. The AESO notes that even if the ratio was calculated using a single quote for each line type, each conductor and each voltage at a point in time, such a ratio would likely still vary from year to year depending on labour and material prices.

D-9.4.3 Limitations and use of the Cost Benchmark database

Cost Benchmark database does not note sufficient level of detail for an apple to apple comparison. For example temporary lines or new lines using existing right of way or new lines interfacing with existing lines are different from new lines on a greenfield location. It would require further work to identify and group largely similar lines. Any such further division would reduce the sample size for each group and potentially change the outcome significantly as well as increase volatility.

Cost Benchmark database does not record information from trend/change authorizations (TCAs), forecast final cost estimates and final cost reports. It therefore frequently contains outdated cost information and occasionally contains outdated length, circuit type and in-service-date. As the project progresses from NID to FA to forecast final to final type cost reports, the cost in particular can change significantly. Any such change in cost may make prior ratio calculation outdated and possibly invalid.

D-9.4.4 Reasonability of classification results

In the 2014 Study, LEI considered that optimized line minimizes losses over minimum lines and thus additional cost of optimized line determines the energy classification. LEI postulated that TFOs would seek approval for and build optimized line when losses savings exceed its additional costs over minimum line. The 2018 Update classification results indicate a larger gap between the cost of optimized line and minimum line. The optimized line capacity factor would have to be quite high for losses savings to exceed its additional costs. The test case in tab “UpdateExample” indicates that optimized line capacity factor would have to exceed 89% over all hours of its lifetime for it to be more economic than minimum line. This is quite unlikely and suggests this high energy classification is unreasonable.

D-9.4.5 Proposed classification values

The AESO has noted its concerns with updated bulk and regional system classification values and provided commentary on reasonability in subsections above. The AESO considers classification results of this 2018 Update to be unreasonable. The AESO considers that continuing the use of bulk and regional system classification from the Commission-approved 2014 Study to be appropriate for 2018-2020 time period. The AESO has accordingly used classification presented in Table D-31 below.

Table D-31 - Bulk and Regional Classification (same as Table D-6)

Class	Bulk	Regional
Demand Related Costs	93.4%	89.5%
Energy Related Costs	6.6%	10.5%

D-10 Implementation considerations

In order to assess the impact of implementing the functionalization and classification results, the AESO looked at the following three considerations:

1. whether results from the study would result in reversing trends in rates that could give confusing price signals;
2. if one part of the study would result in a change that was opposite to a change from another part of the study; and
3. whether functionalization and classification recommendations justify averaging or trending results in order to improve stability of rates.

Functionalization and classification results of the study have been discussed in detail in earlier sections and are presented below in Table D-32.

Table D-32 - Final O&M and capital functionalization and classification results (same as Table D-5 and Table D-6)

Function / Year	2018	2019	2020
Bulk	51.4%	52.8%	51.7%
Regional	25.8%	24.5%	24.6%
POD	22.8%	22.7%	23.7%

Class	Bulk	Regional
Demand Related Costs	93.4%	89.5%
Energy Related Costs	6.6%	10.5%

Table D-33 shows the revenue requirement breakdown after implementing functionalization and classification results. Revenue requirement across bulk and regional rate components (bulk-demand, bulk-energy, regional- demand and regional-energy) is increasing on an annual basis, indicating no reversing trends or inconsistent price signal.

Table D-33 - Revenue requirement breakdown by function by class (same as Table D-8)

Revenue Requirement by Function			
Revenue Requirement Split ($ million)	**2018**	**2019**	**2020**
Bulk - Demand	967	1,113	1,215
Bulk - Energy	68	78	85
Regional - Demand	464	495	554
Regional - Energy	54	58	65
POD	460	513	597
Total	2,013	2,258	2,516

The AESO reviewed the revenue requirement impact of applying only the capital cost functionalization instead of combined capital and O&M cost functionalization results. Table D-34 presents the revenue requirement breakdown if only capital cost functionalization results are applied (ignoring O&M cost functionalization results). Although revenue requirement increases on an annual basis for each rate component, as expected more costs would be functionalized as bulk and less costs would be functionalized as regional and POD if applying capital cost functionalization only.

Table D-34 - Revenue requirement breakdown using capital cost functionalization only (same as Table D 9)

Revenue Requirement by Function			
Revenue Requirement Split ($ million)	**2018**	**2019**	**2020**
Bulk	1,152	1,314	1,434
Regional	475	508	570
POD	386	436	512
Total	2,013	2,258	2,516

Comparing Table D-35 below with Table D-32 above, proportion of costs functionalized as bulk is about 4%-6% higher using capital cost only functionalization. This is sensible given that the bulk system function has less than average associated O&M costs in proportion to capital costs, as compared to the regional and POD functions. Though aggregate capital cost of regional and POD assets is less than bulk assets, these assets outnumber bulk assets and therefore require significantly more O&M costs. The AESO proposes to apply combined capital and O&M functionalization results as these are consistent with cost causation.

Table D-35 - Capital cost only functionalization results (same as Table D-1)

Function / Year	2018	2019	2020
Bulk	57.3%	56.4%	55.3%
Regional	23.5%	23.5%	23.6%
POD	19.1%	20.1%	21.2%

Finally, the AESO examined whether functionalization results change significantly year to year, warranting using different values for each year. Since revenue requirement for each rate component increases year over year, the AESO would apply 2018, 2019 and 2020 functionalization results as is (as presented in Table D-31).