2017 YEAR IN REVIEW

MD&A

Management's Discussion and Analysis of Financial Condition and Results of Operation

MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This management’s discussion and analysis of financial condition and results of operations (MD&A) as of February 15, 2018, should be read in conjunction with the Alberta Electric System Operator’s (AESO) audited financial statements for the years ended December 31, 2017 and 2016 and accompanying notes. This MD&A is intended to provide an understanding of the AESO’s business, financial operations, expectations of the future and management of risk. The MD&A and financial statements are reviewed and approved by the AESO Board. The financial statements are expressed in Canadian dollars.

The AESO is responsible for the operation of Alberta’s fair, efficient and openly competitive energy market for electricity; determining the order of dispatch of electric energy and ancillary services; providing system access service on the transmission system; directing the safe, reliable and economic operation of the interconnected electric system; planning the capability of the transmission system to meet future needs; developing, implementing and administering the renewable electricity program; and administering load settlement.

The AESO recovers its costs through four separate revenue sources by way of collections from market participants, or owners of electric distribution systems and wires service providers for load settlement; there is no government funding for the operations of the AESO.

Summary Annual Highlights

The AESO, a not-for-profit statutory corporation, recovers its operating, intangible asset and property, plant and equipment (PP&E) costs through four separate revenue sources, each of which is designed to recover the costs directly related to the provision of a specific service, as well as a portion of the shared corporate services costs.

($ Millions) Years ended December 31,

	2017	2016	Change	% Change
Collections	**2,008.9**	1,825.7	183.2	10
Deferred revenue	**(14.4)**	(46.4)	32.0	69
Other revenue	**1.3**	0.8	0.5	63
Total revenue	**1,995.8**	1,780.1	215.7	12
Transmission operating costs	**1,850.7**	1,634.9	215.8	13
Other industry costs	**21.2**	22.6	(1.4)	(6)
General and administrative costs	**103.0**	97.5	5.5	6
Amortization and depreciation	**20.4**	24.3	(3.9)	(16)
Interest costs	**0.5**	0.8	(0.3)	(38)
Total costs	**1,995.8**	1,780.1	215.7	12

Numbers may not add due to rounding

Total Costs

Transmission Operating Costs

Transmission operating costs represent wires costs, operating reserves, transmission line losses and other ancillary services costs. In 2017, transmission operating costs are $1,850.7 million, which is $215.8 million or 13 per cent higher than the 2016 costs of $1,634.9 million. This increase is associated with higher overall operating costs in 2017.

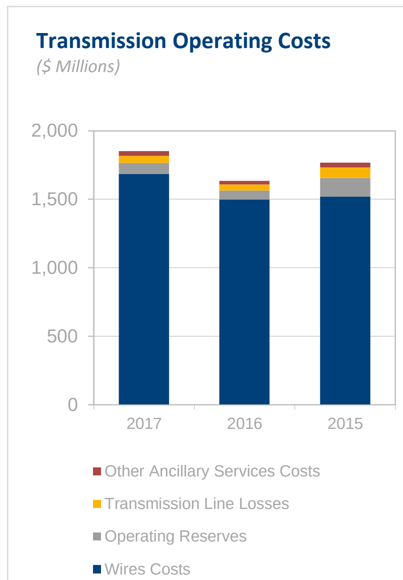
($ Millions) Years ended December 31,

	2017	2016	Change	% Change
Wires costs	**1,685.1**	1,497.6	187.5	13
Operating reserves	**80.7**	66.4	14.3	22
Transmission line losses	**50.7**	43.5	7.2	17
Other ancillary services costs	**34.2**	27.4	6.8	25
Transmission operating costs	**1,850.7**	1,634.9	215.8	13

Numbers may not add due to rounding

Wires Costs

Wires costs represent the amounts paid primarily to Transmission Facility Owners (TFOs) in accordance with their Alberta Utilities Commission (AUC)-approved tariffs and are not controllable costs of the AESO. Wires costs in 2017 are $1,685.1 million, which is $187.5 million or 13 per cent higher than the 2016 costs of $1,497.6 million due to higher regulated rates charged by the TFOs for the current year ($287 million) offset by adjustments related to prior production years ($99 million). The AESO understands that the higher TFO tariffs reflect capital and operating costs associated with projects providing additional transmission system capacity, as well as higher costs to operate and maintain existing transmission facilities.



Operating Reserves

Operating reserves are generating capacity or load that is held in reserve and made available to the System Controller to manage the transmission system supply/demand balance in real time. There are three types of operating reserves with the minimum volumes of operating reserves required based on Alberta Reliability Standards:

- **Regulating reserves** – The generation capacity, energy and maneuverability responsive to the AESO's automatic generation control (AGC) system that is required to automatically balance supply and demand on a minute-to-minute basis in real time.
- **Spinning reserves** – Unloaded generation that is synchronized to the transmission system, automatically responsive to frequency deviation and ready to provide additional energy in response to

an AESO System Controller directive. Spinning reserve suppliers must be able to ramp up their generator within 10 minutes of receiving a System Controller directive.

- **Supplemental reserves** – While similar to spinning reserves, supplemental reserves are not required to respond to frequency deviations. They include unloaded generation, off-line generation or system load that is ready to serve additional energy (generator) or reduce energy (load) within 10 minutes of receiving a System Controller directive.

Operating reserves are procured through an online, day-ahead exchange, where offer prices are indexed to the pool price. In exchange for this payment, the AESO obtains the right to utilize the provider's energy and/or capacity as reserves. The procurement of operating reserve volumes is directly correlated to load and generation. While the prices of operating reserves are indexed to the pool price, changes to the average pool price do not result in proportional changes to the operating reserve costs; the pool price for each hour has a significant impact on the operating reserve costs for that hour. Additionally, during periods of high hourly pool prices, the less expensive operating reserve suppliers may not be available, which results in higher operating reserve costs.

Operating reserve costs in 2017 are $80.7 million, which is $14.3 million or 22 per cent higher than the 2016 costs of $66.4 million. The cost of operating reserves is impacted by actual volumes, hourly pool prices and operating reserve prices. The average hourly pool price is $22 per megawatt hour (MWh) in 2017 compared to $18 per MWh in 2016, representing an increase of 22 per cent. Operating reserve volumes financially settled in 2017 are 7,712 gigawatt hours (GWh) compared to 7,359 GWh in 2016, representing a five per cent increase. The cost variance is mainly attributable to higher pool prices, higher volumes and changes to offer behavior.

Transmission Line Losses

Transmission line losses represent the volume of energy that is lost as a result of electrical resistance on the transmission lines. Volumes associated with line losses are determined through the energy market settlement process as the difference between generation and import volumes, less consumption and export volumes. The hourly volumes of line losses vary based on load and export levels, generation (baseload, peaking units and imports) available to serve load, weather conditions, and changes in the transmission topology. System maintenance schedules, unexpected failures, dispatch decisions on the Alberta Interconnected Electric System (AIES), and short-term system measures (such as demand response) may also affect the volume of losses. The value of line losses is calculated based on the hourly pool price.

The cost of transmission line losses in 2017 is $50.7 million, which is $7.2 million or 17 per cent higher than the 2016 cost of $43.5 million due to the impact of a 22 per cent higher average pool price and higher line loss volumes in 2017. Line loss volumes financially settled in 2017 are 2,222 GWh compared to 2,165 GWh in 2016, representing a three per cent increase.

Other Ancillary Services

The AESO procures other ancillary services for the secure and reliable operation of the AIES. These services are procured through a competitive procurement process where possible, or in instances where such procurement processes may not be feasible, through bilateral negotiations.

In 2017, other ancillary services costs are $34.2 million, which is $6.8 million or 25 per cent higher than the 2016 costs of $27.4 million. The increase is mainly attributable to higher costs related to load shed service for imports and transmission must-run services.

($ Millions) Years ended December 31,

	2017	2016	Change	% Change
Load shed service for imports	**22.9**	18.2	4.7	26
Transmission must-run				
Contracted	**3.0**	-	3.0	100
Conscripted	**0.5**	1.3	(0.8)	(62)
Reliability services	**2.9**	2.9	-	-
Poplar Hill	**2.8**	2.8	(0.0)	(0)
Black start	**2.1**	2.1	(0.0)	(0)
Transmission constraint rebalancing	**0.0**	0.0	0.0	0
Total Other Ancillary Services	**34.2**	27.4	6.8	25

Numbers may not add due to rounding

Load shed service for imports (LSSi) is interruptible load that can be armed to trip, either automatically or manually, on the loss of the Alberta-British Columbia intertie to allow for increased import available transfer capability (ATC). The 2017 costs for LSSi are $22.9 million, which is $4.7 million or 26 per cent higher than the 2016 costs of $18.2 million. LSSi costs are impacted by volume availability, contract prices and AIES requirements for arming and tripping. In the spring of 2017, higher LSSi arming costs were incurred to allow for higher import volumes on the Alberta-British Columbia intertie attributable to above-average water supply in the US Pacific Northwest.

Transmission must-run (TMR) occurs when generation is required to mitigate the overloading of transmission lines associated with line outages, system conditions in real time or the loss of generation in an area. Starting in January 2017, the AESO contracted with a generator in Northwest Alberta to provide TMR services which cost $3.0 million for the year. In circumstances when this service is required for an unforeseeable event and there is no contracted TMR, non-contracted generators may be dispatched to provide this service (referred to as conscripted TMR). Conscripted TMR costs in 2017 are $0.5 million, which is $0.8 million or 62 per cent lower than the 2016 costs of $1.3 million due to fewer operational requirements.

Reliability services are provided through an agreement with Powerex Corp. for grid restoration balancing support in the event of an Alberta blackout and emergency energy in the event of supply shortfall. The agreement came into effect on April 1, 2015.

The Poplar Hill generator provides voltage support (VArs) in addition to power (MW), to support transmission system reliability in the province.

Transmission constraint rebalancing costs are incurred when the transmission system is unable to deliver electricity from a generator to a given electricity-consuming area without contravening reliability requirements. When this occurs, a market participant downstream of a constraint may be dispatched for purposes of transmission constraint rebalancing under the Independent System Operator (ISO) Rules and would receive a transmission constraint rebalancing payment for energy provided for that purpose. Transmission constraint rebalancing came into effect on November 26, 2015. There were no significant events in 2017 and 2016.

Other Industry Costs

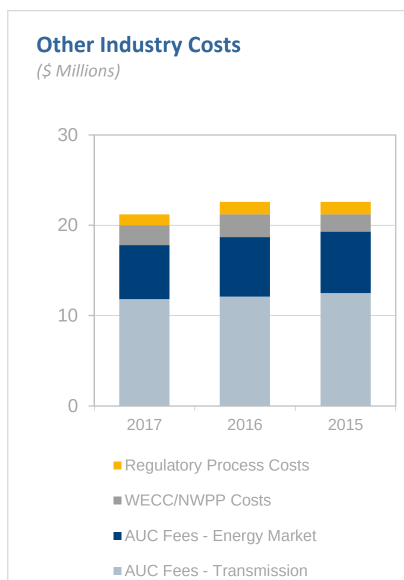
Other industry costs represent fees or costs paid based on regulatory requirements or membership fees for industry organizations, which are not under the direct control of the AESO. These costs relate to the annual administration fee for the AUC, the AESO's share of Western Electricity Coordinating Council (WECC) and Northwest Power Pool (NWPP) membership fees and regulatory process costs. Regulatory process costs are associated with the AESO's involvement in an AUC proceeding to hear objections and complaints to ISO Rules or a regulatory application and costs incurred to respond to specific agency-related directions or recommendations that are beyond the routine operations of the AESO; this does not include application preparation costs.

Other industry costs in 2017 are $21.2 million, which is $1.4 million or six per cent lower than 2016 costs of $22.6 million. The decrease is mainly attributable to lower AUC fees in 2017.

($ Millions) Years ended December 31,

	2017	2016	Change	% Change
AUC Fees – Transmission	**11.8**	12.1	(0.3)	(2)
AUC Fees – Energy Market	**6.0**	6.6	(0.6)	(9)
WECC/NWPP costs	**2.2**	2.5	(0.3)	(12)
Regulatory process costs	**1.2**	1.4	(0.2)	(14)
Other industry costs	**21.2**	22.6	(1.4)	(6)

Numbers may not add due to rounding



Under the provisions of the *Alberta Utilities Commission Act*, AUC operating and capital costs are recovered from natural gas and electricity market participants under its jurisdiction or any person to whom the AUC provides services. Accordingly, the AUC apportions its costs related to its electricity transmission and wholesale electric market activities to the AESO as an AUC administration fee. The AUC levies two separate administration fees to the AESO; a transmission fee that is recovered through the transmission tariff and an energy market fee that is recovered from market participants through the AESO's energy market trading charge on a per-MWh-traded basis.

The AESO's share of WECC membership fees in 2017 is $1.5 million, payable in US dollars, which is $0.1 million or five per cent lower than the 2016 fees of $1.6 million. The decrease in WECC membership fees is the result of a decrease in WECC costs which are allocated to the AESO on a percentage share basis and a strengthening of the Canadian dollar in 2017.

Regulatory process costs in 2017 are $1.2 million, which is $0.2 million or 13 per cent lower than 2016 costs of $1.4 million. The notable regulatory proceedings during 2017 relate to transmission loss factors ($0.3 million); ISO tariff complaints ($0.2 million); AESO participation in the Jasper Interconnection Project proceedings ($0.2 million); and the AESO's contribution to the AUC distribution-connected generation review ($0.2 million).

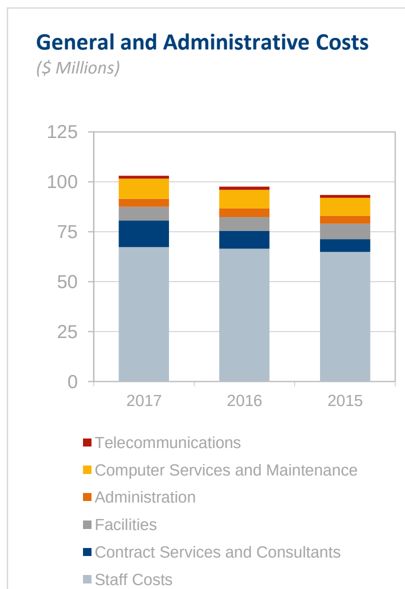
General and Administrative Costs

($ Millions) Years ended December 31,

	2017	2016	Change	% Change
Staff costs	**67.3**	66.4	0.9	1
Contract services and consultants	**13.3**	9.0	4.3	48
Facilities	**6.9**	7.0	(0.1)	(1)
Administration	**3.9**	4.3	(0.4)	(9)
Computer services and maintenance	**10.2**	9.3	0.9	10
Telecommunications	**1.4**	1.5	(0.1)	(7)
General and administrative costs	**103.0**	97.5	5.5	6

Numbers may not add due to rounding

General and administrative costs in 2017 are $103.0 million, which is $5.5 million or six per cent higher than the 2016 costs of $97.5 million. This increase is mainly associated with an increase in staff, contract services and consultants, and computer services and maintenance costs.



Staff Costs

The AESO is committed to the successful delivery of its corporate objectives, and to achieve this, it is supported by knowledgeable and dedicated staff. To retain this strong resource base, a competitive compensation package is offered and a rewarding work environment has been created.

In 2017, staff costs are $67.3 million, which is $0.9 million or one per cent higher than the 2016 costs of $66.4 million.

Contract Services and Consultants

The AESO uses contract services and consultants to supplement staff resources for two general purposes: to provide knowledgeable experts to address specific work assignments and to provide resource support to address workload peaks to maintain seamless operations.

In 2017, contract services and consultants costs are $13.3 million, which is $4.3 million or 48 per cent higher than the 2016 costs of $9.0 million. For 2017, notable changes relate to the following deliverables:

- Transition of the Alberta wholesale electricity market to add a capacity market by 2020 with a focus on the assessment of technical design elements and coordination with industry;
- Debt funding competition and general commercial management for the Fort McMurray West 500kV Transmission Project as significant milestones were reached in 2017;
- Corporate-wide initiatives to develop and sustain practices and systems for AESO compliance with Alberta Reliability Standards and Critical Infrastructure Protection; and
- Additional transmission studies.

Facilities

In 2017, facilities costs are $6.9 million, which is $0.1 million or one per cent lower than the 2016 costs of $7.0 million. The decrease in costs is associated with lower operating costs for the downtown office leases in 2017.

Administration

Administration costs include training, travel, insurance, corporate subscriptions, AESO Board fees and office costs. In 2017, administration costs are $3.9 million, which is $0.4 million or nine per cent lower than the 2016 costs of $4.3 million. The decrease in costs is mainly due to reductions in training and meals offset by additional recruitment costs.

Computer Services and Maintenance

The AESO's investment in information technology infrastructure to support the organization's business operations requires ongoing costs to purchase annual software operating licences and maintenance agreements.

In 2017, computer services and maintenance costs are $10.2 million, which is $0.9 million or 10 per cent higher than the 2016 costs of $9.3 million. The increase in costs is associated with additional licence and maintenance agreements (some of which are associated with capital investments in the prior year).

Telecommunications

The AESO incurs costs for network systems and telecommunications to support general business operations and, to a much larger extent, to support real-time operations. The strategy for developing and maintaining the telecommunication infrastructure is based on the requirement for high service availability, which necessitates redundancies of services and equipment.

In 2017, telecommunication costs are $1.4 million, which is $0.1 million or seven per cent lower than 2016 costs of $1.5 million.

Amortization and Depreciation and Interest

($ Millions) Years ended December 31,

	2017	2016	Change	% Change
Amortization of intangible assets and depreciation of PP&E	**20.4**	24.3	(3.9)	(16)
Interest costs	**0.5**	0.8	(0.3)	(38)

Amortization of Intangible Assets and Depreciation of Property, Plant and Equipment

Intangible assets are amortized and PP&E is depreciated over their estimated useful lives. Intangible assets include the AESO's computer software purchases and development costs.

In 2017, amortization of intangible assets and depreciation of PP&E collectively total $20.4 million, which is $3.9 million or 16 per cent lower than the 2016 amortization of $24.3 million. The decrease in 2017 is due to several factors: the new Energy Management System (EMS) was commissioned mid-2017 with the previous system fully depreciated in the third quarter of 2016; the decision in December 2016 to extend the estimated useful life of the AESO's system coordination facility assets from 19 years to 54 years; and a non-recurring expense in 2016 related to obsolete software.

Interest

Interest costs are associated with borrowing costs for debt financing, portions of which are capitalized when directly incurred during the development or construction of an asset, and financing costs associated with adjustments to the recognized decommissioning liability.

Debt financing occurs to fund intangible asset and PP&E purchases, prepayments of future expenses and working capital deficiencies due to timing differences in the collection of revenues and payment of costs. Intangible assets and PP&E are financed through the AESO's credit facilities and recovered as amortization and depreciation over the useful lives of the assets. Capitalized borrowing costs in 2017 are $0.3 million compared to $0.4 million in 2016.

Interest costs in 2017 are $0.5 million, which is $0.3 million lower than the 2016 costs of $0.8 million. In 2017, the average borrowing requirements decreased due to cash surpluses throughout the year associated with the transmission deferral account.

Intangible Assets and Property, Plant and Equipment

Intangible asset and PP&E purchases total $23.7 million in 2017 compared to $31.9 million in 2016. The AESO's development and acquisition of intangible assets and PP&E, most significantly the investment in information technology infrastructure and business systems, is a key component of business operations. As with all information technology-intensive organizations, the AESO's challenge is to find the appropriate balance between implementing technology advancements, determining the level of information technology development that can be supported by business operations, and validating the overall financial requirement. To address these challenges, a vetting and prioritization process occurs to ensure intangible asset and PP&E purchases achieve the most beneficial and cost-effective results, while continuing to meet operating requirements.

In 2017, over 25 per cent of the intangible asset and PP&E purchases relate to the EMS Implementation Project (version 3.0). The EMS is a critical control system used by the AESO to manage and operate the AIES. This system will deliver necessary cyber security, technology and functionality, in addition to addressing certain Critical Infrastructure Protection standard requirements. The EMS project was initiated in 2014 and commissioned in June 2017.

In 2018, the AESO will begin the construction of an office building adjacent to the existing system coordination facility with occupancy planned for mid-2019. PP&E purchases as of December 31, 2017 are $1.8 million of the estimated $22 million construction cost.

The remainder of the intangible asset and PP&E purchases in both 2017 and 2016 are associated with base system hardware and software application replacements, additions, and continued development and upgrades to operational systems.

The AESO's net book value for intangible assets and PP&E total $91.8 million in 2017 compared to $88.4 million in 2016. As of December 31, 2017, approximately 81 per cent (2016 – 83 per cent) of the net book value relates to computer infrastructure and business systems with the remaining value associated with the AESO's system coordination facility, furniture and office equipment.

Service Area Cost Detail

Allocation of Costs for Revenue Requirements

The AESO recovers its operating, intangible assets and PP&E costs through four separate revenue sources. Each revenue source is designed to recover the costs directly related to a specific service as well as a portion of the shared corporate services costs. The majority of the revenues the AESO collects relate to the recovery of transmission operating costs (wires, ancillary services and transmission line losses costs). The remaining costs (general and administrative, other industry, amortization and depreciation and interest costs) are recovered through a methodology intended to relate the costs to the specific services that they support (transmission, energy market, renewable electricity program or load settlement).

The allocation of costs to one of the AESO's four services is based on the direct or indirect relationship the costs have to one of the services. If an operating cost is directly associated with a service, the cost will be assigned directly to that service (e.g., a consultant cost in the transmission group would be assigned 100 per cent to transmission and recovered through the transmission tariff). Alternatively, if an operating cost is not directly associated with any one service (typical for corporate service areas), the cost will be allocated to the services based on the value of the directly assigned costs. This methodology assumes that the service with the higher direct costs would contribute to a higher demand for general costs (such as corporate services) and therefore be assigned a higher percentage allocation.

Exceptions to this general methodology arise for information technology, office rent, other industry costs and intangible asset and PP&E costs. Information technology costs are allocated based on an activity-based analysis to reflect the nature of the underlying costs. Office rent costs are allocated based on the staff associated with the four services. Other industry costs are allocated based on the nature of the specific cost. Intangible asset and PP&E purchases made to support one service are recovered from that service or alternatively from multiple services based on management judgment, taking into consideration the business or operating activities that will be supported by the systems (hardware and software).

Allocation and Cost Classifications

General Classification	Cost Categories	AESO Services (%) Trans-mission	Energy Market	REP	Load Settlement
Operating	• Wires	100	-	-	-
	• Ancillary services	100	-	-	-
	• Transmission line losses	100	-	-	-
Non-operating	• Other industry • General and administrative • Amortization of intangible assets and depreciation of PP&E • Interest	Costs allocated based on established methodology			

Allocation of Non-Operating Costs

Based on the allocation methodology, the AESO recovers the non-operating costs from the four revenue sources.

($ Millions) Years ended December 31,

		Trans-mission	Energy Market	Renewables Electricity Program	Load Settlement	Total
Other industry	**2017**	**14.9**	**6.3**	**-**	**-**	**21.2**
	2016	15.0	7.6	-	-	22.6
General and administrative	**2017**	**70.4**	**26.4**	**5.1**	**1.1**	**103.0**
	2016	70.2	21.7	4.4	1.2	97.5
Amortization and depreciation	**2017**	**14.1**	**6.2**	**-**	**0.1**	**20.4**
	2016	15.5	8.6	-	0.2	24.3
Interest	**2017**	**(0.1)**	**0.5**	**0.1**	**0.0**	**0.5**
	2016	0.1	0.7	0.0	0.0	0.8
Total	**2017**	**99.3**	**39.4**	**5.2**	**1.2**	**145.1**
	2016	100.8	38.6	4.4	1.4	145.2

Numbers may not add due to rounding

Other Industry

The percentage allocation of other industry costs to the four services is consistent in 2017 and 2016.

General and Administrative

The percentage allocation of general and administrative costs associated with the energy market increased in 2017 due to new capacity market initiatives.

Amortization and Depreciation

The percentage allocation of amortization and depreciation to the four services is consistent in 2017 and 2016.

Interest

The allocation of interest costs is impacted by cash shortfalls and surpluses from various sources including: net book value of intangible assets and PP&E; deferral account balances; deposits such as generating unit owner’s contributions, application fees, security; and prepayments for future expenses. The cash flow sources are associated with each of the service areas to determine the allocation of interest costs and will vary each year.

Total Revenues

The *Electric Utilities Act* (EUA) requires that the AESO operates so that no profit or loss results on an annual basis from its operations. To achieve this, revenue is recognized to the extent of annual operating costs, including the amortization of intangible assets and depreciation of PP&E. When revenue collections differ from the annual operating costs, the difference is recorded as an adjustment to revenue, recognized as other accounts receivable or payable and subsequently collected or refunded. The AESO's four revenue sources are from market participants for transmission, energy market and renewable electricity program participants and from owners of electric distribution systems and wires service providers for load settlement; there is no government funding for the operations of the AESO.

Total Revenue

($ Millions) Years ended December 31,

	2017	2016	Change	% Change
Revenue collections				
Transmission	**1,966.8**	1,784.9	181.9	10
Energy market	**41.3**	40.6	0.7	2
Renewable electricity program	**0.9**	0.0	0.9	100
Load settlement	**1.2**	1.0	0.2	20
Total revenue collections	**2,010.2**	1,826.5	183.7	10
(Deferred revenue) revenue				
Transmission	**(16.8)**	(49.2)	32.4	66
Energy market	**(1.9)**	(2.0)	0.1	5
Renewable electricity program	**4.3**	4.5	(0.2)	(4)
Load settlement	**0.0**	0.3	(0.3)	(100)
Total deferred revenue	**(14.4)**	(46.4)	32.0	69
Total revenue	**1,995.8**	1,780.1	215.7	12

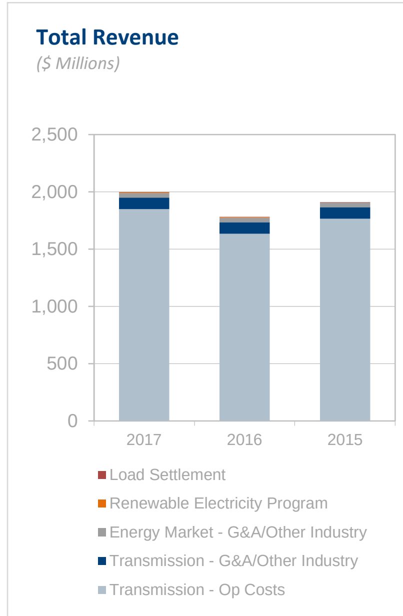
Numbers may not add due to rounding

Transmission

The AESO is responsible for paying all of the costs incurred in managing the provincial transmission system and recovering the costs through a tariff approved by the AUC. The transmission tariff is designed to allocate the costs to all users of the transmission system based on the metered demand and energy for system access service.

On a monthly basis, the AESO invoices market participants for transmission system access services based on approved tariff rates. The AESO also pays for costs associated with providing system access services. The monthly difference in the revenues collected and the costs incurred is accumulated in the AESO's transmission deferral account and can be attributed to several factors:

- forecast variances (pool price volatility, meter volumes and regulatory decisions);
- timing of revenues and costs (monthly fluctuations); and
- any misalignment of approved rates and the current year revenue requirement (delays in having the current year rates approved).



When transmission revenue collections are greater than transmission costs, the surplus is recorded as a reduction in revenue, recognized as other accounts payable and subsequently refunded. When transmission revenue collections are less than transmission costs, the shortfall is recorded as revenue, recognized as other accounts receivable and subsequently collected.

TRANSMISSION DEFERRAL SUMMARY

($ Millions) Years ended December 31,

	2017	2016
Revenue collections	**1,966.8**	1,784.9
Costs	**1,950.0**	1,735.7
Transmission deferred revenue	**(16.8)**	(49.2)
Other accounts (payable) receivable, beginning of year	**(18.6)**	24.7
Disbursement (collection) of the deferral account reconciliation applications:		
2015	**-**	6.7
2013-2014	**-**	(0.8)
Other accounts payable, end of year	**(35.4)**	(18.6)

Numbers may not add due to rounding

As part of the transmission tariff, Deferral Account Adjustment Rider C is intended to bring the transmission deferral account balance for rate categories other than transmission line losses to zero during the following calendar quarter. It is a dollar-per-MWh collection or payment by rate class and rate component. Losses Calibration Factor Rider E is intended to bring the transmission line losses deferral account balance to zero during the remainder of the calendar year. Rate Rider E is a percentage adjustment to all location-specific loss factors.

For rate categories other than transmission line losses, the AESO files a retrospective deferral account reconciliation application with the AUC for approval of the final settlement amounts. The final reconciliation process associates all revenue and cost adjustments by rate category to the appropriate production month and allocates the corresponding charges and refunds to market participants. For transmission line losses, Rate Rider E is a prospective adjustment for the reconciliation of deferral account balances.

The transmission settlement deferral account at December 31, 2017 is a $35.4 million payable compared to an $18.6 million payable at the end of 2016. The change of $16.8 million during 2017 is mainly attributable to an AUC Decision on a TFO transmission tariff true-up application, which occurred in December 2017.

Energy Market

The AESO recovers the costs of operating the real-time energy market through an energy market trading charge on all MWh traded. The AESO's component of the energy market trading charge recovers regulatory process costs, general and administrative costs, interest, amortization of intangible assets and depreciation of PP&E. The energy market trading charge also recovers the AUC administration fee and the operating costs for the Market Surveillance Administrator (MSA), which are organizations that are independent of the AESO's operations.

For 2017, the AESO's component of the energy market trading charge is 33.2 cents per MWh compared to 31.5 cents per MWh in 2016.

Energy market collections are dependent on the energy market trading charge and the volume of energy traded through the power pool.

When energy market revenue collections are greater than energy market costs, the surplus is recorded as a reduction in revenue, recognized as other accounts payable and subsequently refunded. When energy market revenue collections are less than energy market costs, the shortfall is recorded as revenue, recognized as other accounts receivable and subsequently collected.

The energy market deferral account is the accumulated difference between revenues collected and costs paid that is receivable from, or payable to, energy market participants.

ENERGY MARKET DEFERRAL SUMMARY

($ Millions) Years ended December 31,

	2017	2016
Revenue collections	**41.3**	40.6
Costs	**39.4**	38.6
Energy market deferred revenue	**(1.9)**	(2.0)
Other accounts payable, beginning of year	**(2.4)**	(0.4)
Other accounts payable, end of year	**(4.4)**	(2.4)

Numbers may not add due to rounding

The energy market deferral account at December 31, 2017 is a $4.4 million payable compared to a $2.4 million payable at the end of 2016. The energy market trading charge for 2017 was set in advance of the 2016 actual financial results and a forecast update for 2017 expenditures. As a result, the collection surplus continued into 2017 and was addressed in the 2018 energy market trading charge.

Renewable Electricity Program

The AESO is responsible for developing, implementing and administering the Renewable Electricity Program (REP) and recovering the costs through fees charged during each competition and in accordance with Renewable Electricity Support Agreements with generators. The REP service area at the AESO started in 2016 with the Government of Alberta's announcement of the Climate Leadership Plan. Revenue collections started in 2017 with the first competition for renewable attributes under the REP. The AESO costs associated with REP include general and administrative and interest costs.

When REP revenue collections are greater than REP costs, the surplus is recorded as a reduction in revenue, recognized as other accounts payable and subsequently refunded. When REP revenue collections are less than REP costs, the shortfall is recorded as revenue, recognized as other accounts receivable and subsequently collected.

The REP deferral account is the accumulated difference between revenues collected and costs paid that is receivable from, or payable to, market participants in future competitions for renewable attributes with the deferral balance at the conclusion of the REP settled with the Government of Alberta.

RENEWABLE ELECTRICITY PROGRAM DEFERRAL SUMMARY

($ Millions) Years ended December 31,

	2017	2016
Revenue collections	**0.9**	-
Costs	**5.2**	4.5
Renewable Electricity Program revenue	**4.3**	4.5
Other accounts receivable, beginning of year	**4.5**	-
Other accounts receivable, end of year	**8.8**	4.5

Numbers may not add due to rounding

The REP deferral account at December 31, 2017 is an $8.8 million receivable compared to a $4.5 million receivable at the end of 2016. The fee structure for REP includes separate fees associated with the recovery of development, implementation and administration costs. In 2016 and 2017, development and implementation costs were incurred which will be recovered over several years from competition participants and successful bidders following their facility energization dates.

Load Settlement

Under the ISO Rules, costs that are incurred to provide services related to administering provincial load settlement are charged to the owners of electric distribution systems and wires service providers conducting load settlement. The costs associated with load settlement include general and administrative costs, interest, amortization of intangible assets and depreciation of PP&E.

When load settlement revenue collections are greater than load settlement costs, the surplus is recorded as a reduction in revenue, recognized as other accounts payable and subsequently refunded. When load settlement revenue collections are less than load settlement costs, the shortfall is recorded as revenue, recognized as other accounts receivable and subsequently collected.

The load settlement deferral account is the accumulated difference between revenues collected and costs paid that is receivable from, or payable to, owners of electric distribution systems and wires service providers.

LOAD SETTLEMENT DEFERRAL SUMMARY

($ Millions) Years ended December 31,

	2017	2016
Revenue collections	**1.2**	1.0
Costs	**1.2**	1.3
Load settlement revenue	**0.0**	0.3
Other accounts payable, beginning of year	**(0.2)**	(0.5)
Other accounts payable, end of year	**(0.1)**	(0.2)

Numbers may not add due to rounding

The load settlement deferral account at December 31, 2017 is a $0.1 million payable compared to a $0.2 million payable at the end of 2016. The change of $0.1 million is the result of load settlement collections exceeding costs; the collections are based on a forecast of 2017 costs.

Market Surveillance Administrator Charge

A portion of the energy market trading charge collected by the AESO is remitted to the MSA for its revenue requirement in accordance with the *Alberta Utilities Commission Act*. The AESO facilitates the cash collection process for the funding of the MSA through a per-MWh addition to the AESO's energy market trading charge. In 2017, the MSA's portion of the total energy market trading charge is 1.7 cents per MWh compared to nil in 2016.

The MSA's revenue and costs are separate and independent of the AESO's financial records. The AESO records the difference between the payments made to the MSA and the collection on behalf of the MSA in a separate deferral account. At the end of 2017, the MSA collections exceeded the MSA payments, resulting in a deferral accounts payable balance less than $0.1 million. There was no MSA deferral balance at the end of 2016.

Financial Position and Liquidity

At December 31, 2017, the cash position is $113.4 million, an increase of $81.8 million compared to 2016. Notable changes are:

($ Millions) Years ended December 31,

	2017	2016
Funds provided by operations	**20.4**	24.3
Prepayments for future services	**(10.6)**	(11.9)
Payments for long-term payables	**(8.1)**	(6.2)
Cash provided by settlements	**67.4**	77.6
Cash used for capital expenditures	**(27.0)**	(31.5)
Proceeds/(repayment) from debt financing	**43.1**	(31.7)
Other	**(3.4)**	10.3
Increase in cash	**81.8**	30.9

Cash Provided By Settlements

At December 31, 2016, the net balance of the accounts receivable, accounts payable and accrued liabilities, other accounts receivable and other accounts payable, which are settlement-related was a payable of $61.3 million. The balances in these accounts are associated with cash collections for the transmission, energy market, renewable electricity program, load settlement and MSA settlements offset by the cash payments made by the AESO.

During 2017, cash flows for these accounts and the 2017 transactions resulted in a December 31, 2017 net payable balance of $128.7 million. The change in the cash balance of $67.4 million at year end is primarily associated with the November 2017 production month settlement. Based on the number of business days in December 2017, the cash settlement for the production month of November occurred on January 2, 2018 with some market participants making early payments at the end of December that increased the year end cash balance.

Debt Financing and Credit Facilities

As at December 31, 2017, the AESO had the following credit facilities available to fund general operating, intangible asset and PP&E purchasing activities:

($ Millions) Year ended December 31, 2017

	Total	Available	**Used**
Demand revolving facility	160.0	150.0	**53.1**
Demand treasury risk management facility	9.0	9.0	**-**

The demand facility includes a $10.0 million letter of credit at December 31, 2017 and 2016, which is issued as financial security for the AESO's procurement of operating reserves.

Throughout 2016 and 2017, the AESO's credit rating has been AA-/Stable from Standard and Poor's (S&P) Ratings Services. S&P is a leading global provider of independent credit risk research and benchmarks.

Future Outlook

In 2015, the Government of Alberta announced its Climate Leadership Plan (CLP) which is the foundation for a comprehensive set of policy measures to reduce Alberta's greenhouse gas emissions. Of the many initiatives that support the CLP, the AESO, in conjunction with the electricity industry, has been focused on two evolutionary work streams.

In March 2017, the Government of Alberta announced the opening of the first Renewable Electricity Program (REP) competition (REP Round 1) that attracted strong national and international interest in developing renewable generation in Alberta. The REP is intended to encourage the development of 5,000 MW of renewable electricity generation projects that will be connected to the Alberta grid by 2030, while maintaining the reliability of Alberta's transmission system. In each stage of the REP Round 1, expectations were surpassed. The design of the overall REP program and the success of REP Round 1 positions the province well to meet the 30 per cent renewables target by 2030 (30-by-30 target). The four successful projects for REP Round 1 were announced in December 2017, representing nearly 600 MW of renewable wind generation which can be connected to the existing transmission system, with no new transmission costs for Albertans. On February 5, 2018, the Government of Alberta announced REP Rounds 2 and 3 will begin in 2018 for a further 700 MW of renewable generation. During 2018, the AESO will also begin the assessment for dispatchable renewables as well as the role of electricity storage and potential requirements to facilitate a competitive process. The AESO is responsible for the development, implementation and administration of REP. The Government of Alberta, in consort with the AESO, will continue to work towards the 30-by-30 target in 2018.

As the AESO continues to develop and implement REP competitions, coordination with another new work stream at the AESO, the transition from an energy-only market to a new framework that includes both an energy market and a capacity market, has been and will continue to be critical.

In November 2016, the Government of Alberta announced their decision to transition the Alberta wholesale electricity market by adding a capacity market, with the first capacity market auction in 2020 for first delivery of capacity product to occur in 2021. With the new market framework, generators can compete to receive revenue from a market-determined capacity payment for the ability to provide energy when required by the system (capacity) as well as revenue from selling into the energy and ancillary services markets (energy and ancillary services). To assist with the delivery of this mandate, the AESO is leveraging third party expert advice, internal AESO analysis and the collective expertise of Alberta's electricity sector participants and stakeholders to determine certain technical elements of the capacity market design. The design elements will be further advanced in 2018, with the Comprehensive Market Design and consideration for certain legislative changes necessary to enable the development and implementation of the capacity market.

In accordance with the EUA, the AESO Board approves an annual budget to support ongoing operations and to procure transmission services. To recover the costs that are incurred while adhering to the requirement of the EUA for the AESO to operate with no profit or loss on an annual basis, cost recovery mechanisms are established and approved by the AESO Board, and for transmission-related wires costs through TFO tariffs approved by the AUC under Section 37 of the EUA.

For transmission operating and other industry costs in 2018, the AESO established a cost estimate of $2,104.6 million which is $154.6 million or eight per cent higher than the 2017 actual costs of $1,950.0 million. The higher 2018 forecast is associated with higher wires costs based on TFO tariffs approved or applied for by the second quarter of 2017 when the forecast was prepared, in addition to higher ancillary service and transmission line losses costs associated with higher forecasted pool prices. The recovery of the AESO's transmission-related costs occurs through approved transmission tariff rates.

For energy market-related activities, the annual costs are forecast to increase to $42.1 million in 2018 from the 2017 actual costs of $39.4 million, a $2.7 million or seven per cent increase. This forecast increase is associated with higher general and administrative costs. The AESO's portion of the 2018 energy market trading charge will decrease to 18.2 cents per MWh in 2018 compared to 26.2 cents per MWh in 2017, a decrease of 8.0 cents per MWh. The total energy market trading charge, which includes components for funding the AUC and the MSA, will be 26.5 cents per MWh in 2018 compared to 33.2 cents per MWh in 2017.

For the REP-related initiatives, the annual costs are forecast to increase to $6.6 million in 2018 from the 2017 actual costs of $5.2 million, a $1.4 million or 26 per cent increase. This forecast incorporates work activities that will be required to address recent government announcements for additional competitions and assessments for dispatchable renewables and electricity storage.

In 2017, the competitive process for transmission infrastructure reached significant project milestones culminating in the execution of the second and final long-term contract with the AESO. This process began in 2014 when a party was selected through a competitive process to develop, design, construct, finance, own, operate and maintain the Fort McMurray West 500kV Transmission Project. The term of the two contracts will collectively span a period of approximately 38 years. During 2017, the AUC issued a Decision on the Permit and Licence (P&L) to the winning bidder of the 2014 competition which established the routing and granted the approval to construct and operate the facilities with construction beginning in the summer of 2017 and with a targeted in-service date in 2019. Also occurring in 2017 was the Debt Funding Competition for financing of the project which raised $1.4 billion in project financing. Following the conclusion of these two key project deliverables, the final long-term contract was executed.

In March 2018, the AESO will begin the construction of an expansion of the AESO's system coordination facility to construct an adjacent office building which will accommodate additional operational staff in close proximity to the real-time operations with plans for occupancy in mid-2019. The construction costs are estimated at $23 million for an additional 42,000 square feet of space.

Risk Management

The AESO is exposed to various risks in the normal course of business. Many of these are similar to risks faced by other companies including independent electric system operators and wholesale market operators.

The AESO Board is responsible for understanding and assessing the principal risks associated with the AESO's duties and responsibilities and confirming that there is a structure for the protection and enhancement of its assets. AESO Management is responsible for the ongoing operations of the organization including integrating risk management into operations.

The risk management processes that the AESO has developed are designed to proactively identify the risks confronting the AESO, to assess the impact and likelihood of those risks occurring and to determine mitigation strategies to acceptable levels of residual risk.

Risk management is a key element of organizational governance and is characterized by a philosophy of continuous improvement. The key features of the AESO's governance and internal control environment, which facilitate the AESO's risk management processes, are as follows:

- The AESO is established by the EUA. The AESO's business and affairs are governed by Members of the AESO (Members). Members are individuals who are independent from any person having a material interest in the Alberta electricity industry and are appointed by the Alberta Minister of Energy. The Members function as a board of directors (AESO Board) and act in the public interest. The *Alberta Public Agencies Governance Act* is legislation applicable to the AESO that addresses certain duties of the AESO as a "public agency" under that Act.
- AESO policies are developed and approved by the AESO Board or the President and Chief Executive Officer as delegated by the AESO Board. AESO policies are communicated to employees and, as appropriate, to contractors. AESO policies are reviewed on a regular basis and are accessible by employees at all times.
- The AESO is committed to maintaining a high level of ethics and integrity. The AESO Board and AESO Management foster these values throughout the organization and maintain an effective *AESO Complaint Policy*. The AESO maintains a code of conduct applicable to its Members, officers, employees and contractors, which serves as a framework for these individuals when they are faced with difficult situations where laws and regulations may not provide sufficient direction and assistance. The *AESO Code of Conduct* is a policy that all employees must agree to when hired, review at least annually to confirm compliance/non-compliance, and affirm their agreement to abide by the policy. Contractors of the AESO have similar requirements, as appropriate, given the nature of their work for the AESO. Each Member of the AESO Board is bound by the *AESO Code of Conduct* and similarly provides an annual confirmation of their compliance/non-compliance.
- AESO Management is responsible for establishing and maintaining adequate internal controls over financial reporting. These controls are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with International Financial Reporting Standards. Internal controls over financial reporting, no matter how well designed, have inherent limitations and provide only reasonable assurance with respect to financial statement preparation. Accordingly, they may not prevent or detect all misstatements or fraud and error.

  The AESO conducts an annual assessment of the design and effectiveness of its internal controls over financial reporting based on an accepted industry framework. The framework adopted by the AESO for this assessment is the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, AESO Management has concluded that, as of December 31, 2017, the AESO maintained effective internal controls over financial reporting.
- The Audit Committee provides oversight, in accordance with the Audit Committee Charter, on the system of internal controls, the systems for managing risk, the external audit process and the AESO's

process for monitoring compliance with laws and regulations, with a view to adopt best practices, as appropriate.

- The AESO's Controls and Audit Services function provides the AESO with an objective and independent assessment of internal controls, coordinates and reports on risk management activities and identifies opportunities for improvement. The Controls and Audit Services function reports directly to the Audit Committee and, if required, discusses matters with the Audit Committee independent of AESO Management.
- AESO Management identifies and reports any significant risks to the AESO Board and the appropriate AESO Board Committee on a regular basis and provides updates on the implementation of mitigation strategies that are undertaken to address these.
- The AESO, its Members, officers, employees and contractors are extended a degree of statutory liability protection consistent with the AESO's public interest mandate.
- The AESO carries insurance coverage that is reviewed and approved as appropriate by the AESO Board, through the Audit Committee. The insurance coverage may not be adequate to cover all possible risks and the proceeds of any insurance claim may not be adequate to cover all potential losses.

Forward-looking Statements

This MD&A contains forward-looking statements that are subject to certain assumptions and risks that create uncertainties. These assumptions and risks could cause actual results to differ materially from results anticipated by the forward-looking statements.

Additional Information

Additional information relating to the AESO can be found on the corporate website at www.aeso.ca

2017 YEAR IN REVIEW

Financial Statements and Notes

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The financial statements of the Alberta Electric System Operator (AESO) are the responsibility of management and have been approved by the AESO Board. These financial statements have been prepared by management in accordance with International Financial Reporting Standards, appropriate in the circumstances, and include the use of estimates and assumptions that have been made using management's best judgment. Financial information contained in the management's discussion and analysis of financial condition and results of operations (MD&A) is consistent with that in the financial statements.

To discharge its responsibility for financial reporting, management maintains a system of internal controls designed to provide reasonable assurance that the AESO's assets are safeguarded, that transactions are properly authorized and that financial information is relevant, accurate and available on a timely basis. Internal controls are reinforced through the *AESO Code of Conduct*, which set forth the AESO's commitment to conduct business with integrity and to comply with the law.

The AESO Board, through the Audit Committee, is responsible for ensuring management fulfils its responsibility for financial reporting and internal controls. The Audit Committee meets regularly with management, internal auditors and external auditors to discuss any significant accounting, internal control and auditing matters to determine that management is carrying out its responsibilities and to review and recommend the approval of the financial statements by the AESO Board.

The financial statements have been examined by Ernst & Young LLP, the AESO's external independent auditors who are engaged by the AESO Board. The responsibility of these external auditors is to examine the financial statements and express their opinion on the fairness of the financial statements in accordance with International Financial Reporting Standards. The external auditors' report outlines the scope of their examination and states their opinion. Internal and external auditors have access to the Audit Committee, with and without the presence of management.

David Erickson, CPA, CA, ICD.D
President and Chief Executive Officer

Todd D. Fior, CPA, CA
Vice-President, Finance

INDEPENDENT AUDITORS' REPORT

To the Members of the Independent System Operator, operating as Alberta Electric System Operator Board

We have audited the accompanying financial statements of the Alberta Electric System Operator, which comprise the statements of financial position as at December 31, 2017 and 2016, and the statements of income and comprehensive income and cash flows for the years ended December 31, 2017 and 2016, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of the Alberta Electric System Operator as at December 31, 2017 and 2016, and its financial performance and its cash flows for the years ended December 31, 2017 and 2016 in accordance with International Financial Reporting Standards.

Ernst & Young LLP

Calgary, Canada

February 15, 2018
Chartered Professional Accountants

STATEMENT OF FINANCIAL POSITION

(in millions of Canadian dollars)

	December 31, 2017	December 31, 2016
Assets		
Current assets		
Cash and cash equivalents	**$ 113.4**	$ 31.6
Accounts receivable *(note 3)*	**215.1**	89.1
Prepaids and deposits	**7.6**	6.6
	336.1	127.3
Non-current assets		
Long-term other accounts receivable *(note 4)*	**8.8**	4.5
Long-term prepaids *(note 5)*	**36.8**	26.2
Intangible assets, net *(note 6)*	**60.3**	58.0
Property, plant and equipment, net *(note 7)*	**31.5**	30.5
	$ 473.5	$ 246.5
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities (*note 8)*	**$ 335.7**	$ 157.0
Deferred revenue	**0.2**	5.6
Other accounts payable *(note 9)*	**39.9**	21.2
Security deposits *(note 15)*	**1.4**	1.4
Bank debt *(note 10)*	**43.1**	-
	420.3	185.2
Non-current liabilities		
Long-term payables *(note 11)*	**52.5**	60.6
Asset retirement obligation *(note 12)*	**0.7**	0.7
Equity *(note 1)*		-
	$ 473.5	$ 246.5

Commitments and contingencies *(notes 13 and 14)*

See accompanying notes to the financial statements.

STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

For the year ended December 31 (in millions of Canadian dollars)

		2017		2016
Revenue				
Transmission tariff	**$**	**1,949.0**	$	1,735.3
Energy market charge		**39.1**		38.2
Renewable electricity program charges		**5.2**		4.5
Load settlement charge		**1.2**		1.3
Interest and other		**1.3**		0.8
		1,995.8		1,780.1
Operating costs and expenses				
Wires costs		**1,685.1**		1,497.6
Ancillary services costs		**114.9**		93.8
Transmission line losses		**50.7**		43.5
General and administrative *(note 19)*		**103.0**		97.5
Other industry costs		**21.2**		22.6
Amortization and depreciation *(notes 6 and 7)*		**20.4**		24.3
Interest expense *(note 20)*		**0.5**		0.8
		1,995.8		1,780.1
Net income and comprehensive income	**$**	**-**	$	-

See accompanying notes to the financial statements.

STATEMENTS OF CASH FLOWS

For the year ended December 31 (in millions of Canadian dollars)

		2017		2016
Operating activities				
Net income	$	**-**	$	-
Items not affecting cash				
Amortization and depreciation *(notes 6 and 7)*		**20.4**		24.3
Accretion of asset retirement provision *(note 12)*		**0.0**		0.0
Change in long-term other accounts receivable *(note 4)*		**(4.3)**		(4.5)
Change in long-term prepaids *(notes 5 and 13)*		**(10.6)**		(11.9)
Change in long-term payables *(note 11)*		**(8.1)**		(6.2)
Change in non-cash operating working capital balances				
Accounts receivable *(note 3)*		**(126.0)**		22.2
Other accounts receivable		**-**		24.7
Prepaids and deposits		**(1.0)**		(0.1)
Accounts payable and accrued liabilities *(note 8)*		**182.0**		19.6
Deferred revenues		**(5.4)**		5.6
Other accounts payable *(note 9)*		**18.7**		20.3
Security deposits *(note 15)*		**(0.0)**		0.1
Net cash provided by operating activities		**65.7**		94.1
Investing activities				
Additions to intangible assets *(note 6)*		**(17.4)**		(24.3)
Additions to property, plant and equipment *(note 7)*		**(6.3)**		(7.7)
Change in non-cash investing working capital balances				
Accounts payable and accrued liabilities *(note 8)*		**(3.3)**		0.5
Net cash (used in) investing activities		**(27.0)**		(31.5)
Financing activities				
Change in debt financing *(note 10)*		**43.1**		(31.7)
Net cash provided by (used in) financing activities		**43.1**		(31.7)
Increase in cash position		**81.8**		30.9
Beginning of year		**31.6**		0.7
End of year	**$**	**113.4**	$	31.6
Cash interest paid *(note 10)*	**$**	**0.8**	$	1.2

See accompanying notes to the financial statements.

NOTES TO THE FINANCIAL STATEMENTS

(All amounts are in millions of Canadian dollars unless otherwise indicated)

1. Nature of Operations

The Independent System Operator (ISO), operating as the Alberta Electric System Operator (AESO), is a statutory corporation established on June 1, 2003 under the *Electric Utilities Act* (EUA) of the Province of Alberta.

The AESO is responsible for operating Alberta's fair, efficient and openly competitive energy market for electricity; determining the order of dispatch of electric energy and ancillary services; providing system access service on the transmission system; directing the safe, reliable and economic operation of the interconnected electric system; planning the capability of the transmission system to meet future needs; developing, implementing and administering the renewable electricity program; and administering load settlement.

The AESO's business is governed by Members of the AESO (Members). Members are individuals who are independent from any person or entity having a material interest in the Alberta electricity industry and are appointed by the Alberta Minister of Energy. The Members function as a board of directors (AESO Board) and act in the public interest. As of December 31, 2017, the AESO Board has four committees: Audit Committee; Human Resources Committee; Governance and Nominations Committee; and Power System Committee.

The EUA requires that charges to industry, including the transmission tariff, energy market charge, renewable electricity program charges and load settlement charge, be set to recover the costs required to operate the AESO, and that the AESO be operated so no profit or loss results on an annual basis from its operations. The AESO has no equity and accordingly these statements contain no Statement of Changes in Equity.

2. Summary of Significant Accounting Policies

STATEMENT OF COMPLIANCE ►These financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

The AESO Board authorized these financial statements for issue on February 15, 2018.

BASIS OF MEASUREMENT ► The financial statements have been prepared on the historical cost basis except for financial instruments that are measured at fair value.

FUNCTIONAL AND PRESENTATION CURRENCY ► The financial statements are presented in millions of Canadian dollars, which is the AESO's functional currency.

SIGNIFICANT ACCOUNTING JUDGMENTS AND ESTIMATES ► The preparation of these financial statements requires management to select appropriate accounting policies and to make judgments, estimates, and assumptions that could affect the reported amounts of assets, liabilities, revenues, expenses and disclosures of contingent assets and liabilities during the period. Most often these estimates and judgments concern matters that are inherently complex and uncertain. Judgments and estimates are reviewed on an on-going basis; changes to accounting estimates are recognized prospectively.

The key judgments and sources of estimation uncertainty are described below:

- **Useful lives of intangible assets and property, plant, and equipment** - Useful lives are determined based on past experience and current facts, taking into account future expected usage and potential for technological obsolescence.
- **Asset retirement obligation** - Measurement of the AESO's asset retirement obligation requires the use of estimates with respect to the amount and timing of the asset retirement; the extent of site remediation required; and related future cash flows, inflation rates and discount rates. The estimated obligation is present valued using a risk-adjusted, market-based discount rate. A change in estimated cash flows, market interest rates, or timing could have a material impact on the carrying amount of the obligation.
- **Impairment of long-lived assets** - The AESO conducts impairment tests on long-lived assets annually and where impairment indicators exist.

CHANGES IN ACCOUNTING ESTIMATES ► As a result of operational considerations, the AESO has reassessed the following estimates, which are not considered to have a material impact:

- Effective December 1, 2016, system coordination facility assets are considered to have a 54-year estimated useful life (previously 19 years). This change of estimate impacts the depreciation of the asset and the corresponding asset retirement obligation (asset and liability).
- Effective January 1, 2016, furniture and office equipment assets are considered to have a 10-year useful life (previously three years).

REVENUE RECOGNITION ► The AESO's revenue is derived through four separate charges: (i) transmission tariff; (ii) energy market charge; (iii) renewable electricity program charges; and (iv) load settlement charge. Each of these charges is set to recover the costs directly attributable to a specific service as well as a portion of the shared corporate services costs. Consistent with the requirements of the EUA, which requires the AESO to operate with no annual profit or loss, revenue is recognized equivalent to the aggregate of annual operating costs on a service area basis.

Transmission tariff revenue is recognized on a monthly basis consistent with the billing cycle in which the AESO invoices market participants for transmission system access services. Revenues are based on the metered demand and energy for system access service, as specified in the Alberta Utilities Commission-approved tariff rates.

When a market participant reduces or terminates contract capacity for system access service, a lump sum payment may be required in lieu of notice under the terms of the transmission tariff. A payment received by the AESO in advance of the effective date of a change to a system access service agreement is recognized as deferred revenue and subsequently recognized as transmission tariff revenue on the effective date of the change.

Energy market charge revenue is recognized on a monthly basis consistent with the billing cycle in which the AESO invoices market participants to recover the costs of operating the real-time energy market. Revenues are based on the per-megawatt-hour energy market charge and the volume of energy traded through the power pool.

Renewable electricity program revenue is recognized as the AESO invoices market participants during each competition and in accordance with renewable electricity support agreements. Revenues are based on the costs directly attributable to the renewable electricity program services.

Load settlement revenue is recognized as the AESO invoices load settlement agents. Revenues are based on the costs directly attributable to the load settlement services.

The AESO utilizes deferral accounts to record the differences between revenues collected and costs paid with the amounts recognized as other accounts receivable or other accounts payable. On an individual basis for the transmission, energy market, renewable electricity program and load settlement services, in circumstances where collections are greater than costs, the surplus is recorded as a reduction in revenue, recognized as other accounts payable and subsequently refunded. In circumstances where collections are less than costs, the shortfall is recorded as revenue, recognized as other accounts receivable and subsequently collected. The refunds or collections are settled with market participants for the transmission, energy market, and renewable electricity program services and with the owners of electric distribution systems and wires service providers for load settlement services.

Interest and other revenue represents revenue received from third parties and includes, but is not limited to, bank interest and interest on past due accounts; cancellation and performance forfeitures by market participants; a government grant; sublease rent and services; market participant fees; and cost recoveries for training courses. Interest and other revenue is recognized on the accrual basis as the revenue is earned.

As directed in the *Alberta Utilities Commission (AUC) Act*, the AESO is required to provide funding for the Market Surveillance Administrator (MSA), a separate statutory corporation. The amounts paid by the AESO are recovered through the energy market charge as directed in the EUA. The energy market charge included in the AESO's statement of income and comprehensive income does not include amounts recovered related to the MSA's funding requirements and the AESO's costs do not include amounts related to the operations of the MSA.

Revenues are measured at the fair value of the consideration received or receivable.

OTHER ACCOUNTS RECEIVABLE/PAYABLE ► As the EUA requires the AESO to be managed with no profit or loss on an annual basis from its operations, differences in revenues collected and costs paid are: recorded as adjustments to revenue; recognized as other accounts receivable or other accounts payable; and subsequently collected or refunded. The collection of deferral account shortfalls and payment of deferral account surpluses is embodied in the legislative rights granted in the EUA and *Renewable Electricity Act (REA)* to the AESO Board or AUC.

The AESO recognizes amounts as long-term other assets or other liabilities when the collection or refund is expected to occur beyond one year from the date of the statement of financial position.

OFFSETTING FINANCIAL INSTRUMENTS ► Financial assets and financial liabilities are offset and the net amount is reported in the statement of financial position if there is a legally enforceable right to offset the recognized amounts, and if the AESO intends either to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

CASH AND CASH EQUIVALENTS ► Cash and cash equivalents consist of cash and term deposits issued by credit-worthy financial institutions with maturities within three months from the date of acquisition.

INTANGIBLE ASSETS ► Intangible assets are recorded at cost less accumulated amortization. Cost includes the purchase price, plus any additional costs directly attributable to the development of the asset and preparing the asset for its intended use. Such costs include staff, consulting resources and borrowing costs incurred during the development of qualifying assets.

Maintenance and repair costs which do not enhance or extend the useful life of the asset are expensed as incurred.

Amortization is calculated on a straight-line basis over the estimated useful lives of the assets. No amortization is provided on intangible assets under development. The expected useful lives, amortization method and residual values of the assets are reviewed annually, with any changes accounted for on a prospective basis. Amortization periods for intangible assets are shown in the following table.

Computer software	5 to 7 years; or Over the term of the licence agreement for customization of Software as a Service

Intangible assets are retired when they are fully amortized and derecognized when no future benefits are expected to arise from their use.

PROPERTY, PLANT AND EQUIPMENT ► Property, plant and equipment are recorded at cost less accumulated depreciation. Cost includes the purchase price, plus any additional costs directly attributable to the construction of the asset and preparing the asset for its intended use. Such costs include materials, staff, consulting resources, borrowing costs incurred during construction for qualifying assets and asset retirement costs.

Maintenance and repair costs which do not enhance or extend the useful life of the asset are expensed as incurred.

Depreciation is calculated on a straight-line basis over the estimated useful lives of the assets. No depreciation is provided on assets under construction. The expected useful lives, depreciation method and residual values of the assets are reviewed annually, with any changes accounted for on a prospective basis. Depreciation periods for property, plant and equipment are shown in the following table.

System coordination facility	Over the land lease term ending in 2060
Computer hardware	4 to 7 years
Backup coordination centre	Over the lease term ending in 2033
Leasehold improvements	Over the applicable lease terms ending in 2024
Furniture and office equipment	10 years

Property, plant and equipment are retired when they are fully depreciated and derecognized when no future benefits are expected to arise from their use.

CAPITALIZED BORROWING COSTS ► Borrowing costs directly incurred during a development or construction period of substantial duration are added to the cost of the asset. Qualifying assets are those that take a substantial period of time to develop or construct and are developed over periods of time exceeding 12 months. Borrowing costs are considered to be directly attributable if they could have been avoided if the expenditure on the qualifying asset had not been made. Borrowing cost capitalization commences when expenditures and borrowing costs are incurred and ceases when the qualifying asset is substantially complete and ready for its intended use.

IMPAIRMENT OF INTANGIBLE ASSETS AND PROPERTY, PLANT AND EQUIPMENT ► Impairment indicators for intangible assets with finite useful lives and property, plant and equipment are reviewed annually or whenever events or changes in circumstance may indicate possible impairment. Impairment is assessed at the cash-generating unit level to which the asset belongs. Based on the legislative requirements associated with the AESO's financial operations, an asset impairment cannot occur as the recoverable amount is equal to its carrying amount.

ASSET RETIREMENT OBLIGATIONS ► Decommissioning liabilities are legal and constructive obligations for decommissioning assets. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire the asset and is recognized at the present value of expected future cash flows. Decommissioning liabilities are added to the carrying amount of the associated asset and depreciated over its estimated useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning. Decommissioning liabilities may change as a result of a new decommissioning cost estimate or the timing of the obligation.

PROVISIONS AND CONTINGENCIES ► Provisions are recognized when a present obligation (legal or constructive) is a result of a past event, it is probable that an outflow of resources will be required to settle the obligation, and the amount can be reliably estimated. The amount recognized as a provision is the best estimate of the expenditure required to settle the obligation at the end of the reporting period.

If the effect is material, provisions are determined by discounting the expected future cash flows at a risk-adjusted, market-based discount rate. If discounting is used, the increase in the provision due to the passage of time is recognized in interest expense.

A contingent liability is a possible obligation, and a contingent asset is a possible asset, that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the AESO. A contingent liability may also be a present obligation that arises from past events that is not recognized because it is not probable that an outflow of economic resources will be required to settle the obligation or the amount of the obligation cannot be measured reliably.

Neither contingent liabilities nor assets are recognized in the financial statements. However, a contingent liability is disclosed, unless the possibility of an outflow of resources is remote. A contingent asset is only disclosed where an inflow of economic benefits is probable.

EMPLOYEE BENEFITS OBLIGATIONS ► A liability is recognized for a present legal or constructive obligation to pay an amount as a result of past service provided by employees, and the obligation can be estimated reliably. The liability recognizes the amount expected to be paid for short-term employee benefits such as the short-term incentive plan; paid annual leave; paid sick leave; post-employment benefits; and termination benefits.

LEASES ► When an arrangement is entered into for the use of capital assets, the arrangement is evaluated to determine whether it contains a lease. A specific asset would qualify as a lease if fulfilment of the arrangement is dependent on the use of the specific asset. An arrangement constitutes the right to use the asset if the AESO has the right to control the use of the underlying asset. When an arrangement is determined to be a lease, the lease is classified as either operating or financing depending on whether substantially all the risks and rewards of the asset have been transferred.

LONG-TERM PREPAIDS ► The AESO recognizes advance cash payments associated with operating leases, information technology licences and ancillary service agreements with terms longer than one year from the statement of financial position date as long-term assets.

LONG-TERM PAYABLES ► A generating unit connected to the Alberta Interconnected Electric System is required to pay the AESO a generating unit owner's contribution which is refundable over a period of not more than 10 years, subject to satisfactory annual performance. The carrying amount of the contributions is measured as the amount required to settle the obligations at the end of the reporting period. The AESO recognizes refundable amounts as long-term liabilities when the refund term is longer than one year from the statement of financial position date.

FINANCIAL INSTRUMENTS ► The AESO classifies financial instruments at their initial recognition. Financial assets are classified as fair value through profit or loss (including held-for-trading), held-to-maturity investments, loans and receivables or available-for-sale. Financial liabilities are classified as fair value through profit or loss or amortized cost.

COMPREHENSIVE INCOME ► As the AESO does not have any other comprehensive income, net income equals comprehensive income.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED ►

The following standards and interpretations are not yet effective and have not been applied in preparing these financial statements.

- **IFRS 9 Financial Instruments ►** The final standard replaces IAS 39 Financial Instruments: Recognition and Measurement and all previous versions of IFRS 9. The entire standard provides guidance and requirements on classification and measurement of financial assets and liabilities, impairment and hedging. The standard is effective for annual periods beginning on January 1, 2018; the AESO has adopted the new standard on the effective date. The AESO expects minimal impact upon adoption.

- **IFRS 15 Revenue From Contracts With Customers ►** The new standard provides a framework that replaces existing revenue recognition guidance. Entities apply a five-step model to determine when to recognize revenue and at what amount. The model specifies that revenue should be recognized when (or as) an entity transfers control of goods or provides services to a customer at the amount to which the entity expects to be entitled. The standard is effective for annual periods beginning on January 1, 2018; the AESO has adopted the new standard on the effective date using the full retrospective method.

  The AESO's primary revenue-generating sources are associated with performance obligations to provide system access services and accessibility to the power pool for the purpose of trading electricity to market participants.

  The AESO's current recognition, presentation and disclosure of revenue align to IFRS 15. The AESO's revenue recognition practices are not impacted by the following considerations: variable or allocation of transaction prices; agency relationships; returns, discounts or warranties; and non-cash transactions.

- **IFRS 16 Leases** ► The standard replaces IAS 17 Leases. The standard provides guidance and requirements for lessees for a single recognition and measurement model for leases with required recognition of assets and liabilities for most leases. The standard is effective for annual periods beginning on or after January 1, 2019, with early adoption permitted when also applying IFRS 15 Revenue from Contracts with Customers. The AESO is currently assessing the impact of adopting the standard.

COMPARATIVE FIGURES ► Certain comparative figures have been reclassified to conform to the current period's presentation.

3. Accounts Receivable

The transmission settlement receivables are subject to offsetting *(note 18)*.

As at	**Dec 31, 2017**	Dec 31, 2016
Transmission settlement, net	**206.7**	82.3
Energy market settlement	**7.7**	5.1
Trade	**0.7**	1.7
	215.1	89.1

4. Other Accounts Receivable

As at	**Dec 31, 2017**	Dec 31, 2016
Long-term portion Renewable electricity program receivable	**8.8**	4.5

5. Long-term Prepaids

As at	**Dec 31, 2017**	Dec 31, 2016
Licences and maintenance	**1.2**	1.7
Prepaid rent	**3.5**	3.8
Prepaid reliability services agreement (*note 13)*	**32.1**	20.7
	36.8	26.2

6. Intangible Assets

	Computer Software	Intangible Assets Under Development	Total
Cost:			
January 1, 2016	108.1	19.6	127.7
Additions	9.6	14.7	24.3
Transfers	6.0	(6.0)	-
Write-off	-	(1.3)	(1.3)
Retirements	(21.5)	-	(21.5)
December 31, 2016	**102.2**	**27.0**	**129.2**
Additions	16.0	1.4	17.4
Transfers	23.6	(23.6)	-
Retirements	(34.4)	-	(34.4)
December 31, 2017	**107.4**	**4.8**	**112.2**
Accumulated amortization:			
January 1, 2016	75.8	-	75.8
Amortization	16.9	-	16.9
Retirements	(21.5)	-	(21.5)
December 31, 2016	**71.2**	**-**	**71.2**
Amortization	15.1	-	15.1
Retirements	(34.4)	-	(34.4)
December 31, 2017	**51.9**	**-**	**51.9**
Net Book Value:			
December 31, 2016	31.0	27.0	58.0
December 31, 2017	**55.5**	**4.8**	**60.3**

Intangible assets under development relate to intangible assets associated with various computer software development projects that were not commissioned or operational by the end of the year.

For the 12 months ended December 31, 2017, $5.4 million of payroll costs associated with staff directly involved in preparing intangible assets for their intended use have been capitalized (2016 – $5.6 million).

The additions of intangible assets include $0.2 million (2016 – $0.3 million) of capitalized borrowing costs at an average rate of 2.1 per cent (2016 – 1.9 per cent).

7. Property, Plant and Equipment

	System Coordination Facility	Computer Hardware	Backup Coordination Centre	Leasehold Improvements	Furniture and Office Equipment	Assets Under Construction	Total
Cost:							
January 1, 2016	23.9	28.1	2.0	1.2	0.7	6.6	62.5
Additions	-	4.0	-	0.0	0.4	3.2	7.6
Transfers	-	1.2	-	-	-	(1.2)	-
Changes to asset retirement obligation	(0.4)	-	-	-	-	-	(0.4)
Retirements	-	(2.1)	-	-	(0.0)	-	(2.1)
December 31, 2016	**23.5**	**31.2**	**2.0**	**1.2**	**1.1**	**8.6**	**67.6**
Additions	1.3	3.0	-	0.1	0.0	1.9	6.3
Transfers	0.0	7.9	-	-	-	(7.9)	-
Retirements	-	(17.0)	-	-	-	-	(17.0)
December 31, 2017	**24.8**	**25.1**	**2.0**	**1.3**	**1.1**	**2.6**	**56.9**
Accumulated depreciation:							
January 1, 2016	11.2	20.8	0.2	0.4	0.5	-	33.1
Depreciation	1.1	4.8	0.1	0.1	0.0	-	6.1
Retirements	-	(2.1)	-	-	(0.0)	-	(2.1)
December 31, 2016	**12.3**	**23.5**	**0.3**	**0.5**	**0.5**	**-**	**37.1**
Depreciation	0.3	4.8	0.1	0.1	0.0	-	5.3
Retirements		(17.0)					(17.0)
December 31, 2017	**12.6**	**11.3**	**0.4**	**0.6**	**0.5**	**-**	**25.4**
Net Book Value:							
December 31, 2016	11.2	7.7	1.7	0.7	0.6	8.6	30.5
December 31, 2017	**12.2**	**13.8**	**1.6**	**0.7**	**0.6**	**2.6**	**31.5**

Assets under construction relate to property, plant and equipment in development that was not commissioned or operational by the end of the year.

For the 12 months ended December 31, 2017, $0.5 million of payroll costs associated with staff directly involved in preparing property, plant and equipment for their intended use have been capitalized (2016 – $0.3 million).

The additions of property, plant and equipment include $0.1 million (2016 – $0.1 million) of capitalized borrowing costs at an average rate of 2.1 per cent (2016 – 1.9 per cent).

8. Accounts Payable and Accrued Liabilities

The transmission settlement payables are subject to offsetting *(note 18)*.

As at	**Dec 31, 2017**	Dec 31, 2016
Transmission settlement, net	**232.6**	132.0
Energy market settlement	**79.3**	-
Trade payables	**3.8**	7.3
Generating unit owner's contribution *(note 11)*	**8.3**	6.4
Accrued liabilities	**11.7**	11.3
	335.7	157.0

9. Other Accounts Payable

As at	**Dec 31, 2017**	Dec 31, 2016
Transmission payable	**35.4**	18.6
Energy market payable	**4.4**	2.4
Load settlement payable	**0.1**	0.2
MSA payable	**0.0**	-
	39.9	21.2

10. Bank Debt

The AESO has credit facilities of $160 million in unsecured demand revolving loan facilities. The facilities provide that the borrowings may be made by way of fixed rate offer loans, prime loans or bankers' acceptances, which bear interest at the rates specified in fixed rate offer loans, at the bank's prime rates, or at bankers' acceptance rates plus a stamping fee. There is an option to request letters of credit under the credit facilities.

In addition to the credit facilities, a demand treasury risk management facility of $9 million in deemed risk content is available to provide for interest swaps for up to $35 million in notional debt. This facility was not used in 2017 or 2016.

At December 31, 2017, $43.1 million was drawn on the available credit facilities (2016 – nil) and a $10.0 million letter of credit was issued as security for operating reserve procurement.

The amount of interest paid during 2017 was $0.8 million (2016 – $1.2 million) at an average interest rate of 2.1 per cent (2016 – 1.9 per cent).

11. Long-term Payables

Under the terms of the transmission tariff, a market participant is required to pay a generating unit owner's contribution. The contribution amount is determined based on variable terms in accordance with the transmission tariff. A market participant is entitled to a refund of the generating unit owner's contribution in annual amounts during the refund period which is not more than 10 years. The eligibility for the annual refund amount is dependent on the generation facility meeting specified performance criteria.

	Total
January 1, 2016	66.8
Contributions received	0.2
Contributions reclassified to current *(note 8)*	(6.4)
December 31, 2016	**60.6**
Contributions received	0.2
Contributions reclassified to current *(note 8)*	(8.3)
December 31, 2017	**52.5**

12. Asset Retirement Obligation

The land on which the AESO's system coordination facility resides must be returned to its original state at the conclusion of the land lease on request by the landlord, the Government of Alberta. The asset retirement obligation recognizes the approximate third party costs for the decommissioning based on the timing of expected cash flows.

The AESO has estimated the net present value of the decommissioning liability based on an independent third party valuation of current costs to dismantle the system coordination facility and restore the land.

On December 1, 2016, the estimated useful life of the system coordination facility was extended by 35 years to 2060 and consistent with this extension, the estimated timing for the decommissioning liability has been revised to 2060 (2015 – estimated to occur in 2025).

The present value of the decommissioning liability is $0.6 million (2016 - $0.6 million). The total undiscounted future liability is estimated to be $5.6 million (2016 – $5.6 million). The AESO has calculated the present value of the obligation using a discount rate of 4.8 per cent (2016 – 4.8 per cent) to reflect the market assessment of the time value of money and an inflation rate of 2.0 per cent (2016 – 2.2 per cent).

13. Commitments

(i) The AESO is committed to operating leases for real estate that have expiry dates between 2024 and 2033. Renewal options exist to extend certain leases to dates ranging between 2053 and 2060. The estimated future minimum lease payments associated with these non-cancellable operating leases for the initial lease terms are as follows:

	As of December 31, 2017
No later than 1 year	6.0
Later than 1 year and no later than 5 years	25.0
Later than 5 years	20.1
	51.1

The AESO, as a sub-landlord, has entered into a sublease agreement for a portion of the system coordination facility with expiry in 2025 and renewal options to extend the sublease to 2045. The estimated future minimum sublease payments expected to be received under this non-cancellable sublease are $1.2 million.

During the year ended December 31, 2017, $6.0 million (2016 - $6.2 million) was recognized as an expense in respect of these operating leases and $0.1 million (2016 - $0.1 million) was recognized as revenue in respect of the sublease.

(ii) To fulfil the duties of the AESO in accordance with the EUA, the AESO manages the procurement of ancillary services through contracts with third-party suppliers. These ancillary services include operating reserves, reliability services, load shed, system restoration and transmission must-run. The contracts are for future generation capacity and load reduction capabilities with expiry dates ranging from 2019 to 2030, in addition to short-term contracts for operating reserves. The amount to be paid under each contract is dependent on fixed and variable terms. Variable terms include items such as commodity prices, dispatch volumes and frequency of events and are determined when the services are provided. The fixed payments associated with the service contracts are as follows:

	As of December 31, 2017
No later than 1 year	8.5
Later than 1 year and no later than 5 years	17.0
Later than 5 years	-
	25.5

(iii) In 2015, the AESO entered into a 15-year reliability services agreement with Powerex Corp. for the provision of certain emergency energy services from British Columbia, including grid restoration balancing support in the event of an Alberta blackout and emergency energy in the event of supply shortfall. The total cost of the agreement is $42.9 million was paid in equal amounts in the three-year period from 2015 to 2017. As the payments were made, they were recognized as long-term prepaids on the statement of financial position and amortized on a straight-line basis over the 15-year term of the agreement.

	Total
January 1, 2016	9.3
Payment made	14.3
Payment reclassified to current	(2.9)
December 31, 2016	**20.7**
Payment made	14.3
Payment reclassified to current	(2.9)
December 31, 2017	**32.1**

(iv) Under the direction of the EUA, the AESO established and executed an AUC-approved competitive process for transmission infrastructure and in December 2014, selected the party to develop, design, build, finance, own, operate and maintain the Fort McMurray West 500 kV Transmission Project. In February 2017, the AUC granted the permit and licence for this transmission project. In January 2018, the AUC approved the transmission facility owner's tariff rates which are based upon the monthly amounts in the project agreement between the AESO and the transmission facility owner.

The AESO is obligated to pay monthly amounts for the use of the transmission facilities over the operating period set out in the project agreement, which commences on the energization date for the transmission facilities (targeted to be in 2019) and continuing until the expiry of the agreement in approximately 35 years. The monthly amounts are applicable for the entire term of the agreement, subject to allowable adjustments (e.g., inflation). The amounts payable will be confirmed in future periods by the occurrence or non-occurrence of certain events (e.g., a termination of the project agreement would affect monthly amounts). The AESO will recover the monthly amounts paid to the transmission facility owner through the ISO tariff in the same manner that AUC-approved amounts paid to other transmission facility owners are recovered.

	As of December 31, 2017
No later than 1 year	-
Later than 1 year and no later than 5 years	463.9
Later than 5 years	3,193.3
	3,657.2

Pursuant to Section 37 of the *Electric Utilities Act*, each owner of an electric transmission facility must submit to the AUC for approval a tariff setting out the rates to be paid by the AESO to the owner for the use of the owner's transmission facility. The AESO pays seven other transmission facility owners in the province for the use of their facilities in accordance with AUC-approvals. Each transmission facility owner operates in an AUC-approved service area and typically applies to the AUC for approval of its costs one to three years in advance, in contrast to the fore mentioned long-term contractual agreement with the AESO. For these transmission facility owners, uncertainties relating to the AUC-approved amounts and timing of future cash flows limit the reliability of quantifying similar financial obligations.

(v) In December 2017, the AESO executed Renewable Electricity Support Agreements (RESA) for 600 megawatts with selected counterparties to promote the development of renewable generation in Alberta at a weighted average price of $37 per megawatt hours. The agreements require the AESO to make variable payments or collections over a 20-year term based on the difference between the counterparty-specific contract price and the hourly pool prices for the actual volumes of electricity delivered to the Alberta Interconnected Electric System (AIES). The 20-year term begins upon energization of the new or expanded facility which must occur prior to the end of 2019.

The *Renewable Electricity Act* stipulates that the funding or settlement for RESA financial obligations, excluding fees for the development, implementation and administration of the Renewable Electricity Program (REP), is funded by or provided to the Minister of Energy.

14. Contingencies

As a result of events that have occurred, the AESO may become party to a claim or legal action arising in the normal course of business. While the outcome of these matters is uncertain, the AESO does not currently believe that the outcome related to these matters or any amount that the AESO may be required to pay would have a materially adverse effect on the AESO as a whole.

15. Security Deposits

Security requirements for market participant financial obligations in excess of their unsecured credit limits are met with cash deposits and letters of credit. All market participants who have financial obligations to the AESO must adhere to the ISO Rules and transmission tariff terms and conditions regarding security requirements. Unsecured credit is granted by the AESO to organizations (or guarantors) with an acceptable credit rating from an AESO-recognized bond rating agency; to organizations that do not have a credit rating if they qualify for an AESO-determined proxy credit rating; and to organizations that have an exempt status as determined through government legislation or AUC rulings. The unsecured credit granted by the AESO to an organization is limited based on the AESO's assessment of the organization's credit worthiness.

16. Key Management Compensation

Key management personnel include members of executive management and the AESO Board, a total of 19 individuals (2016 – 16 individuals). The compensation paid or payable to key management for services are as follows:

As of December 31,	**2017**	2016
Salaries and other short-term employee benefits	**4.7**	4.3

17. Government-Related Entities

The members of the AESO Board are appointed by the Minister of Energy of the Government of Alberta. Based on this relationship, the AESO's transactions and outstanding balances with the Government of Alberta and other entities in a similar related party relationship with the Government of Alberta are reported.

The AESO considers the following entities as government-related:

- **Balancing Pool**: established under the EUA to manage the transition to competition in Alberta's electric industry;
- **Alberta Utilities Commission** (AUC): established under the AUC Act to ensure that the delivery of Alberta's utility service takes place in a manner that is fair, responsible and in the public interest; and
- **Market Surveillance Administrator** (MSA): established under the AUC Act to monitor Alberta's electricity and retail natural gas markets to ensure that they operate in a fair, efficient and openly competitive manner.

Pursuant to the EUA, on an annual basis the Balancing Pool determines an annualized amount to pay distributions from its revenues to eligible consumers or collect shortfalls in its revenues from eligible consumers; the Government of Alberta guarantees the obligations of the Balancing Pool. Through the transmission tariff, the AESO facilitates the allocation of the annualized amount as directed in the EUA. In 2017, the annualized amount was a shortfall of $66.0 million which was collected from eligible consumers and paid to the Balancing Pool (2016 – $190.2 million was paid to eligible consumers and collected from the Balancing Pool).

The Balancing Pool is a market participant and received $549.9 million related to electricity sales in 2017 (2016 – $137.3 million).

The Balancing Pool paid the AESO $22.7 million for contracts related to supply transmission services in 2017 (2016 – $3.9 million).

As directed in the AUC Act, the AESO is required to pay an administration fee to the AUC. The amounts paid by the AESO are recovered through the transmission tariff and the energy market charge as directed in the EUA. In 2017, $17.8 million was paid to the AUC (2016 – $18.7 million).

As directed in the AUC Act, the AESO is required to provide funding for the MSA. The amounts paid by the AESO are recovered through the energy market charge as directed in the EUA. In 2017, $2.2 million in payments were made to the MSA (2016 – nil).

The AESO leases 12 acres of land in the Calgary area from the Minister of Infrastructure of the Government of Alberta. The land lease is for a 55-year term ending in 2060 which is comprised of an initial 20-year term which began in 2005 followed by several renewal options at the discretion of the AESO. In 2017, $0.1 million of costs were incurred (2016 – $0.1 million).

18. Financial Instruments

Financial Instrument	Designated Category	Measurement Basis	Associated Risks	Fair Value at December 31, 2017 and 2016
Cash and cash equivalents	Held for trading	Fair value	Liquidity risk	Carrying value approximates fair value due to short-term nature and variable interest rates
Accounts receivable Other accounts receivable	Loans and receivables	Initially at fair value and subsequently at amortized cost	Credit risk	Carrying value approximates fair value due to short-term nature
Long-term receivables	Loans and receivables	Initially at fair value and subsequently at amortized cost	Credit risk	Carrying value approximates fair value
Accounts payable and accrued liabilities Other accounts payable Deferred revenue	Other financial liabilities	Initially at fair value and subsequently at amortized cost	Liquidity risk Market risk	Carrying value approximates fair value due to short-term nature
Security deposits	Other financial liabilities	Initially at fair value and subsequently at amortized cost	Liquidity risk	Carrying value approximates fair value due to short-term nature
Bank debt	Other financial liabilities	Initially at fair value and subsequently at amortized cost	Liquidity risk Market risk	Carrying value approximates fair value due to short-term nature and variable interest rates
Long-term payables	Other financial liabilities	Initially at fair value and subsequently at amortized cost	Liquidity risk	Carrying value approximates fair value due to the nature of the liability

Nature and Extent of Risks Arising From Financial Instruments

The AESO is exposed to the following types of risks in relation to its financial instruments:

(a) **CREDIT RISK** ► The risk that a counterparty may default on its financial obligations to the AESO. Due to the EUA requirement that the AESO be operated with no profit or loss from its operations, credit risk is ultimately borne by market participants, though managed by the AESO.

Counterparties are granted certain levels of unsecured credit based on their long-term unsecured debt rating provided by a major reputable corporate rating service satisfactory to the AESO or, in the absence of the availability of such ratings, the AESO has satisfactorily reviewed the counterparty for creditworthiness as appropriate. Letters of credit, cash on deposit and legally enforceable right to set-off are used to mitigate risk where appropriate. As at December 31, 2017 and 2016, the amount of financial assets that were past due was not material and there were no material uncollectible receivable balances.

(b) **MARKET RISK** ► The risk of a potential negative impact on the statement of financial position and/or statement of income and comprehensive income resulting from adverse changes in the value of financial instruments as a result of changes in certain market variables. This includes interest rate price and foreign exchange risks.

Bank debt is comprised of short-term bankers' acceptances or prime rate advances that bear interest at market rates. Accordingly, the exposure to interest rate price risk in relation to the bank debt at the statement of financial position date is not material.

Investments are comprised of short-term bankers' acceptances or term deposits that bear interest at market rates. Accordingly, the exposure to interest rate price risk in relation to the investments at the statement of financial position date is not material.

The AESO conducts less than one per cent of its business in US dollars and accordingly is subject to currency risk associated with changes in foreign exchange rates in relation to payables. The AESO monitors its exposure to currency risk and reviews whether the use of derivative financial instruments is appropriate to manage potential fluctuations in foreign exchange rates. The AESO has not entered into any derivative instruments with respect to currency risk.

(c) **LIQUIDITY RISK** ► The risk that the AESO will not be able to meet its obligations associated with financial liabilities. The AESO does not consider this to be a significant risk as the available credit facilities provide financial flexibility to allow the AESO to meet its obligations as they come due. The AESO does not consider there to be a present risk in relation to funds available to the AESO under the existing credit facilities.

In managing capital, the AESO reviews its cash flows from operations, including the transmission tariff, energy market charge, renewable electricity program charges and load settlement charge, to determine whether there are sufficient funds to cover its operating costs and pay for intangible asset and property, plant and equipment purchases. To the extent that the cash flows are not sufficient to cover these expenditures, the AESO utilizes debt financing. The AESO has no equity or externally imposed capitalization requirements except as described in note 1.

Summarized Quantitative Data Associated with the Above Risks

(a) **CREDIT RISK ►** At December 31, 2017, the AESO's maximum exposure to receivable credit risk was $223.8 million (December 31, 2016 – $93.6 million), which is the aggregate of accounts receivable.

The AESO's receivables are due from counterparties that have provided security to the AESO or have been granted unsecured credit based on satisfactory credit ratings. As at December 31, 2017, the amount of financial assets that were past due was not material (December 31, 2016 – not material).

(b) **MARKET RISK ►** The AESO is exposed to currency risk on $1.1 million (December 31, 2016 – $0.5 million) of US dollar denominated financial liabilities at December 31, 2017.

If the Canadian dollar decreases (increases) against the US dollar by five per cent prior to the payment by the AESO, operating costs would increase (decrease) by less than $0.1 million (December 31, 2016 – less than $0.1 million) and intangible asset costs would increase (decrease) by less than $0.1 million (December 31, 2016 – less than $0.1 million).

(c) **LIQUIDITY RISK ►** The AESO's bank debt and accounts payable and accrued liabilities generally have contractual maturities of six months or less. The estimated future undiscounted annual refund amounts associated with long-term payables are as follows:

	As of December 31, 2017
2019	9.3
2020	9.4
2021	9.8
2022	7.8
2023 and thereafter	16.2
	52.5

Offsetting Financial Assets and Liabilities

The following transmission settlement receivables and payables are subject to offsetting as presented in the statement of financial position. *(notes 3 and 8)*

As at	**Dec 31, 2017**	Dec 31, 2016
Transmission settlement receivables, gross	**301.5**	117.3
Transmission settlement, offsets	**(94.8)**	(35.0)
Transmission settlement receivables, net	**206.7**	82.3

As at	**Dec 31, 2017**	Dec 31, 2016
Transmission settlement payables, gross	**327.4**	167.0
Transmission settlement, offsets	**(94.8)**	(35.0)
Transmission settlement payables, net	**232.6**	132.0

19. General and Administrative Expenses

General and administrative expenses classified by nature are as follows:

As of December 31,

	2017	2016
Salaries and benefits	**67.3**	66.4
Other	**35.7**	31.1
	103.0	97.5

20. Interest Expense

As of December 31,

	2017	2016
Interest on bank debt	**0.8**	1.2
Capitalized interest *(notes 6 and 7)*	**(0.3)**	(0.4)
Accretion of asset retirement obligation *(note 12)*	**0.0**	0.0
	0.5	0.8