2019 ANNUAL REPORT

Canadian Natural

30 Years of Premium Value

2019 Performance Highlights

Canadian Natural's diverse and balanced asset base along with a continued focus on effective and efficient operations delivered industry leading free cash flow, creating significant value for the Company's shareholders in 2019.

			2019		2018		2017
FINANCIAL ($ millions, except per common share amounts)							
Product sales (1)		**$**	**24,394**	$	22,282	$	18,360
Net earnings		**$**	**5,416**	$	2,591	$	2,397
Per common share	– basic	**$**	**4.55**	$	2.13	$	2.04
	– diluted	**$**	**4.54**	$	2.12	$	2.03
Adjusted net earnings from operations (2)		**$**	**3,795**	$	3,263	$	1,403
Per common share	– basic	**$**	**3.19**	$	2.68	$	1.19
	– diluted	**$**	**3.18**	$	2.67	$	1.19
Cash flows from operating activities		**$**	**8,829**	$	10,121	$	7,262
Adjusted funds flow (3)		**$**	**10,267**	$	9,088	$	7,347
Per common share	– basic	**$**	**8.62**	$	7.46	$	6.25
	– diluted	**$**	**8.61**	$	7.43	$	6.21
Cash flows used in investing activities		**$**	**7,255**	$	4,814	$	13,102
Net capital expenditures (4)		**$**	**7,121**	$	4,731	$	17,129
Long-term debt (5)		**$**	**20,982**	$	20,623	$	22,458
Shareholders' equity		**$**	**34,991**	$	31,974	$	31,653
Debt to book capitalization (6)			**37%**		39%		41%

(1) 2017 comparative figures have been restated in accordance with adoption of IFRS 15 on January 1, 2018. See note 2 of the Company's consolidated financial statements.
(2) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. The derivation of this measure is discussed in the Company's Management's Discussion and Analysis ("MD&A").
(3) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital reinvestment and to repay debt. The derivation of this measure is discussed in the MD&A.
(4) Net capital expenditures is a non-GAAP measure that the Company considers key as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. The derivation to this measure is discussed in the MD&A.
(5) Includes the current portion of long-term debt.
(6) Calculated as net current and long-term debt; divided by the book value of common shareholders' equity plus net current and long-term debt.

TABLE OF CONTENTS

	2019	2018	2017
OPERATING			
Daily production, before royalties			
Crude oil and NGLs (Mbbl/d)			
North America - excluding Oil Sands Mining and Upgrading	**406**	351	360
North America - Oil Sands Mining and Upgrading	**395**	426	282
North Sea	**28**	24	23
Offshore Africa	**21**	20	20
	850	821	685
Natural gas (MMcf/d)			
North America	**1,443**	1,490	1,601
North Sea	**24**	32	39
Offshore Africa	**24**	26	22
	1,491	1,548	1,662
Barrels of oil equivalent (MBOE/d) (1)	**1,099**	1,079	962
Drilling activity (2)			
North America	**102**	504	521
North Sea	**5**	4	2
Offshore Africa	**1**	2	—
	108	510	523
Company Gross proved plus probable reserves (3) (4)			
Crude oil and NGLs (MMbbl)			
North America	**12,361**	11,453	9,958
North Sea	**176**	186	180
Offshore Africa	**114**	121	125
	12,651	11,760	10,263
Natural gas (Bcf)			
North America	**9,513**	9,633	9,520
North Sea	**21**	38	32
Offshore Africa	**72**	63	67
	9,607	9,734	9,619
Barrels of oil equivalent (MMBOE)	**14,252**	13,382	11,866

(1) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.
(2) Net wells. Excludes net stratigraphic test and service wells.
(3) Year-end proved plus probable reserves were prepared using forecast prices and costs.
(4) May not add due to rounding.

1,099,000

BOE/D RECORD PRODUCTION

49%

OF BOE PRODUCTION IS SCO, LIGHT CRUDE OIL & NGLS

Letter to our Shareholders

In 2019, Canadian Natural celebrated its 30th year as an Exploration and Production ("E&P") company and demonstrated the strength of our diverse, balanced and vast asset base and our ability to generate industry leading free cash flow of $4.6 billion. Our model is predicated on balancing our four pillars of capital allocation: I) returns to shareholders; II) balance sheet strength; III) resource value growth and; IV) opportunistic acquisitions. In 2019, we delivered on all four of these pillars.

As we exited 2018, the Canadian oil industry was faced with wider than normal crude oil differentials as a result of continued delays in new market egress from the Western Canadian basin. In response to wider differentials, the Alberta Government implemented, effective January 1, 2019, mandatory production curtailments to address this issue, under which companies were issued production quotas each month. Given Canadian Natural's strong and flexible asset base, we were able to implement and execute on a curtailment optimization strategy through 2019, ensuring that we maximized the value of our production quota and free cash flow generation.

In early 2019, Canadian crude oil pricing differentials quickly returned to normal levels, which coupled with our record production of 1,099,000 BOE/d, drove record adjusted funds flow of $10.3 billion in 2019 and net earnings of $5.4 billion. Returns to shareholders were significant in 2019 totaling $2.7 billion, including a 12% increase in the Company's quarterly dividend and over $940 million returned via share repurchases. This marked the 19th consecutive year of dividend increases for our shareholders. Throughout 2019, Canadian Natural demonstrated its commitment to its balance sheet through the net retirement of approximately $2.35 billion of bonds and term facilities, while capturing an opportunistic acquisition of substantially all of the Devon Canada assets, which closed on June 27, 2019. Subsequent to year end, the Board of Directors approved a 13% increase to our quarterly dividend to $0.425 per common share, marking the 20th consecutive year of increases.

Our asset base remains one of the strongest in our industry, underpinned by our long life low decline asset base which represents approximately 73% of our crude oil production. These assets are low geological risk and generate significant free cash flow due to the low cost of maintaining production, amenable to economic margin enhancement and greenhouse gas ("GHG") emissions reducing investments. Augmenting these assets are our low capital exposure projects which allow for significant additional returns for investors in the right pricing environment.

Complementing these strong assets is our culture of leveraging technology, innovation and continuous improvement which drove significant value growth as the Company captured approximately $550 million of incremental margin improvements in 2019. Our culture, strong track record of capturing opportunities, attention to detail and disciplined cost management practices have allowed us to identify and target similar savings of up to $900 million in 2020 and beyond.

The Company's industry leading Oil Sands Mining and Upgrading segment, which represents 36% of our production, continued to drive strong results in 2019, delivering high operations reliability and continued execution on synergies between our two mine sites, lowering the operating cost structure of our high value synthetic crude oil by approximately 50% since 2013 to $22.56/bbl (US$19.01/bbl). These long life low decline assets can deliver decades of free cash flow and we are currently developing a number of technologies which have potential to economically achieve our longer term aspirational goal of net zero GHG emissions from our Oil Sands operations.

Similarly, our thermal in situ assets accounted for 15% of our 2019 average production base and are amenable to technology investments which have the potential to generate more crude oil at lower cost and lower GHG emissions. Thermal in situ production in 2019 increased approximately 56% from 2018 levels due to the strong startup of our Kirby North project and economic pad additions at Primrose in the second half of 2019, as well as the successful integration of the Devon Canada Jackfish assets, further strengthening our long life low decline asset base. We were able to quickly integrate the acquired assets and due to the successufl integration, we were able to reduce operating costs at Jackfish by approximately $3.50/bbl or 30% from the initial operating cost estimates by capturing synergies across our thermal assets.

In the Company's North American E&P assets, crude oil and NGL production, representing 22% of 2019 production was slightly lower than 2018 levels, reflecting the Company's capital allocation decisions given government mandated production curtailments. While natural gas has declined over time due to strategic allocation of capital to higher return assets, we remain one of Canada's largest natural gas producers (22% of 2019 production mix). In 2019, the Company began its Liquids Enhancement and Gas Storage ("LEGS") pilot at Septimus. Initial results are meeting expectations and if successful, LEGS technology has the potential to add significant value by unlocking liquids rich development while preserving natural gas production for future development in a higher price environment.

$10.3 BILLION
RECORD ADJUSTED FUNDS FLOW

$2.7 BILLION
RETURNED TO SHAREHOLDERS

N. MURRAY EDWARDS
Executive Chairman

STEVE W. LAUT
Executive Vice-Chairman

TIM S. MCKAY
President

MARK A. STAINTHORPE
Chief Financial Officer and
Senior Vice-President, Finance

International production was strong in 2019, representing approximately 4% of 2019 production. In the North Sea, the Company focused on high netback producer wells in 2019, with results exceeding expectations. In Offshore Africa, the Company completed its drilling program at Baobab in early 2019, with production from the new wells meeting expectations. These producing assets continue to provide a strong source of free cash flow. Beyond this, the Company's non-operated position in a potential high impact exploration prospect offshore South Africa is targeted to progress with additional drilling and a seismic program targeted by the operator in 2020.

In 2019, Canadian Natural executed on its commitment to deliver proactive, environmentally responsible operations, furthering work on our various projects (see our website at www.cnrl.com for further details). While we have already reduced our corporate GHG intensity by 30% from 2012 levels and continue to execute on our industry leading abandonment and reclamation program, we have recently announced several new targets involving reductions in GHG emissions and water intensity. Canadian Natural remains one of the industry's most responsible producers and is a leader on the environmental, social and governance ("ESG") front.

As we enter 2020, Canada and Canadian Natural continue as leaders in ESG performance. As such, we believe Canada's energy will be a necessary and integral part of delivering the world's future energy needs with a lower carbon footprint. Canadian Natural has invested over $3.7 billion in research and development over the last 10 years and continues to invest in new and emerging technologies that will have a significant impact on the Company's environmental footprint. We have already demonstrated significant improvements in all ESG areas, and have a defined plan to further progress in the coming years, including an aspirational goal of net zero GHG emissions from our Oil Sands operations.

Effective and efficient operations will continue to be a focus for the Company in 2020. Our 2020 capital budget is flexible and disciplined and was originally targeted, when finalized on December 4, 2019, at approximately $4.05 billion, driving corporate production guidance volumes of between 1,137,000 and 1,207,000 BOE/d. Subsequent to year end 2019, in early March 2020, as a result of the volatility in crude oil pricing, Canadian Natural reduced its 2020 capital budget by approximately $100 million to $3.95 billion. With the continued volatility in commodity pricing, the Company in mid-March 2020 identified and implemented further opportunities to reduce its 2020 capital spending budget to approximately $2.96 billion, but with no impact to our stated production guidance volumes of between 1,137,000 and 1,207,000 BOE/d. Decisions regarding additional opportunities to further reduce capital spending will be made as part of the Company's prudent management of its capital expenditures.

As part of the continued focus on effective and efficient operations, the Company has reviewed its compensation program in light of the current commodity volatility. Effective April 2020, the President's annual salary has been reduced 20%, while other members of the Management Committee will have annual salaries reduced by 15% and Vice-President positions will have annual salaries reduced by 12%. Concurrently, the Board of Directors has also agreed to reduce their annual Board cash retainer by 10%.

Canadian Natural is a unique, sustainable and robust E&P company that delivers significant and industry leading free cash flow, strong returns on capital and growing returns to shareholders. This is underpinned by the Company's vast inventory of assets and disciplined capital allocation to our four pillars to maximize shareholder value: returns to shareholders, balance sheet strength, resource value growth and opportunistic acquisitions. Canadian Natural targets to continue its top tier performance and minimize the Company's environmental footprint through leveraging the expertise of its people and continued economic investments in technology, innovation and continuous improvement.

N. MURRAY EDWARDS
Executive Chairman

STEVE W. LAUT
Executive Vice-Chairman

TIM S. MCKAY
President

MARK A. STAINTHORPE
Chief Financial Officer
and Senior Vice-President,
Finance

Our World-Class Team

Our proven strategy and disciplined business approach are supported by our dedicated teams and experienced management team. Canadian Naturals exponential growth over the last 30 years reflects dedication, planning and resilience from its main resource: our employees.

G. Aalders, E. Aasen, L. Abadier, A. Abadier, Z. Abbas, T. Abbasi, J. Abbott, M. Abbott, D. Abbott, I. Abdi, A. Abdolmaleki, M. Abdulrhman, W. Abeda, A. Abeda, D. Abel, R. Abel, V. Abeng, T. Abercrombie, G. Abou Mechrek, R. Abrams, A. Abramyan, J. Abramyk, N. Abro, C. Acharya, R. Ackerman, J. Acosta, J. Acteson-Grill, N. Adair, T. Adair, S. Adam, I. Adam, A. Adams, D. Adams, K. Adams, M. Adams, D. Adamson, P. Adamson, C. Adan, T. Adbous, D. Addinall, A. Adebayo, Y. Adebayo, S. Adel, M. Aden, A. Adesanya, O. Adigun, M. Aditiakusuma, B. Adkins, R. Adzabe Ella, N. Agarwal, J. Agate, F. Agbadou, M. Aghdasi, A. Agnihotri, K. Agombar, U. Agu, I. Agu, R. Aguilera Maestre, A. Agustin, C. Agyemang-Badu, R. Ahmad, N. Ahmad, S. Ahmad, J. Ahmad, A. Ahmad, M. Ahmad, I. Ahmad, M. Ahmadi, A. Ahmadi, F. Ahmadloo, A. Ahmari, S. Ahmed, R. Ahmed, A. Ahmed, M. Ahoonmanesh, R. Aidoo, R. Aikens, D. Aikins, G. Ailsby, T. Ailsby, J. Airton, K. Aitchison, S. Aitken, S. Ajayi, T. Ajayi, J. Ajedegba, L. Ajijolaiya, S. Akhtar, R. Akinde, D. Akins, A. Akinsanya, N. Akolkar, J. Akolkar, S. Akolkar, C. Alarcon, J. Alcala, E. Alconcel, N. Aldi, J. Aleman, A. Alexander, P. Alexander, D. Alexander, J. Alexander, G. Ali, A. Ali, R. Aliazas, H. Aljanabi, M. Al-Kaisy, C. Allan, J. Allan, E. Allan, J. Allard, E. Allard, L. Allegretto, J. Allen, W. Allen, H. Allen, B. Allen, T. Allen, W. Allerton, D. Allibone, J. Allison, R. Allison, S. Allport, J. Allsop, A. Almaktary, B. Almen, M. Almestar Bustamante, S. Almstrong, Y. Alnumi, J. Alonso, Y. Al-Saeedi, A. Al-Saleem, R. Al-Samarrai, S. Al-Siani, A. Alstad, C. Altrogge, J. Alvarez, J. Alvarez Luzon, B. Alyman, D. Amalaman, G. Amalia, J. Aman, M. Amar, T. Amara, A. Amay, A. Amer, B. Amer, K. Amer, J. Amero, D. Ames, E. Amos, W. Amy, R. Amyotte, A. Amyotte, D. Anctil, J. Andel, D. Anders, T. Andersen, D. Andersen, R. Anderson, K. Anderson, G. Anderson, W. Anderson, J. Anderson, D. Anderson, C. Anderson, M. Anderson, N. Anderson, P. Anderson, A. Anderson, B. Anderson, L. Anderson, D. Andreoli, C. Andres, J. Andres, B. Andrews, T. Andrews, D. Andrews, E. Anfort, C. Angeles, G. Angeles, P. Angell, L. Angen, K. Angerman, M. Anis, R. Annett, L. Anongba, M. Ansah-Sam, C. Anscombe, A. Ansell, C. Ansong-Danquah, D. Ansorger, R. Anstett, V. Anstey, G. Anstey, L. Antal, E. Antle, C. Antoine, M. Antoine, A. Anton, K. Antonishyn, J. Antoniuk, A. Antunes, H. Aparicio Ramos, P. Appiah, J. Aquila, R. Aranguren, F. Arano, L. Arbour, C. Arcand, C. Archibald, J. Argan, L. Arias, H. Arias, J. Aristimuno, J. Arizaleta, S. Arjomandi, J. Arkley, T. Armfelt, J. Armstrong, D. Armstrong, A. Armstrong, J. Arnault, B. Arneson, J. Arnold, B. Arnold, C. Arnold, V. Aron, F. Arrau, F. Arrieta, M. Arsenault, L. Arthur, A. Arthur Brown, E. Arthurs, B. Artz, S. Arunachalam, B. Asake, J. Ashe, Z. Ashmore, M. Aslam, A. Aslam, R. Aslin, R. Asmundson, S. Aspden, R. Aspden, H. Aspeslet, M. Asselstine, D. Assinger, J. Asso, V. Assohou-Ouattara, F. Assoko-Mve, A. Assoum, S. Assoumane, R. Astalos, A. Astalos, I. Astete, M. Atchudda Reddy, N. Athavan, A. Atienza, R. Atkins, J. Atkinson, K. Atkinson, L. Attreo, E. Au, G. Au, J. Auch, W. Aucoin, D. Aucoin, P. Aucoin, P. Auger, B. Auger, A. Auger, L. Auger, D. Auger, G. Augustine, C. Aular, C. Austin, R. Austin, F. Avery, S. Avery, C. Aviles, O. Awodein, A. Ayasse, W. Ayles, J. Ayub, F. Azam, Z. Azim, A. Babiarz, O. Babiker, K. Babu, C. Bachelet, C. Bachman, W. Bachmeier, A. Baciulica, C. Backer, A. Badamchi Zadeh, K. Baddeley, W. Bader, N. Badgley, O. Baffoh, G. Baggs, N. Bagheri, K. Bagley, M. Bahiraei, B. Bahlieda, D. Baichev, J. Baier, N. Baier, D. Baier, R. Bailer, S. Bailey, T. Bailey, J. Bailey, K. Bailey, B. Bailey, S. Baillargeon, M. Baillie, B. Bain, E. Bain, C. Baird, B. Bairstow, D. Baisley, D. Bak, L. Bakaas, J. Baker, A. Baker, R. Baker, C. Baker, D. Baker, F. Bakita, D. Bakkar, J. Balacang, A. Balajadia, M. Balan, B. Balaski, B. Baldonado, J. Baldonado, G. Baldwin, C. Baldwin, M. Baldwin, R. Baldwin, M. Baleja, P. Balfour, R. Balfour, I. Balicanta, J. Balkam, C. Balko, C. Ball, M. Ball, J. Ball, P. Ball, G. Ball, K. Ballantyne, J. Ballard, S. Ballas, B. Balog, D. Balogoum, A. Balsom, D. Balson, J. Baltesson, B. Baluyot, R. Bama, L. Bamba, B. Bamber, R. Bamotra, R. Banack, J. Banak, M. Banas, D. Banash, J. Banawa, N. Banerjee, S. Banfield, R. Banfield, O. Bango, S. Banik, L. Banks, J. Banks, C. Ban-Nelson, R. Bannerholt, B. Bannis, C. Bantaya, M. Banwait, R. Barabe, G. Barber, D. Barber, J. Barbour, L. Bardoel, G. Barfield, K. Barham, M. Bari, M. Barilea, S. Barker, R. Barker, A. Barley, S. Barlund, D. Barnes, M. Barnes, N. Barnes, R. Barnes, V. Barnes, B. Barnett, S. Barr, D. Barr, E. Barreto, C. Barrett, T. Barrett, M. Barrett, R. Barrett, T. Barretto, S. Barriault, C. Barrie, K. Barron, R. Barron, D. Barron, D. Barry, A. Barstad, P. Barter, B. Bartlett, C. Bartlett, M. Bartlett, D. Bartman, M. Bartman, A. Barysheva, J. Basabe, K. Basarab, N. Basi, R. Basile, L. Basines, P. Bass, S. Basso, C. Bast, A. Bastardo, H. Bastidas Martinez, C. Bastien, S. Basu, M. Batac, C. Bateman, D. Bateman, P. Bateman, M. Bateman, T. Bateman, D. Bath, L. Bath, S. Batina, M. Batovanja, D. Batt, U. Batta, R. Batten, C. Battrum, B. Battyanie, J. Batuyong, D. Bauer, R. Bauer, T. Bauld, C. Baumgardner, M. Baxter, J. Baxter, J. Bayles, D. Bayley, F. Bayuk, A. Bazowski, B. Beach, A. Beacon, W. Beals, C. Beaman, J. Beamish, G. Bean, D. Bean, R. Bear, C. Beaton, N. Beaton, G. Beaton, C. Beattie, S. Beattie, A. Beattie, J. Beauchamp, S. Beauchamp, J. Beaudoin, C. Beaudoin, R. Beaudoin, C. Beaudrie, B. Beaulac, M. Beaulieu, J. Beaulieu, L. Beaunoyer, F. Beaver, K. Beazer, J. Becaria, D. Bechtel, N. Beck, C. Becker, R. Becker, R. Beckner, S. Beckow, M. Bedard, L. Bedard, D. Bedell, G. Bedi, A. Bedi, M. Bednarchuk, T. Beebe, S. Beebe, M. Beeks, C. Beeler, K. Begg, W. Behnke, J. Behrens, A. Belah, R. Belanger, G. Belanger, H. Belas, R. Belcourt, L. Belcourt, K. Belcourt, J. Belik, R. Belisle, A. Bell, S. Bell, K. Bell, J. Bell, D. Bell, L. Bell, N. Bell, R. Bell, J. Bellavance, J. Beller, M. Beller, E. Bellerose, A. Bellettini, J. Belliveau, C. Bellows, A. Bellows, S. Belseck, M. Belzile, D. Belzil-Pittman, M. Bembridge, K. Bendahmane, A. Bendahmane, C. Bender, R. Benedictson, M. Benko, T. Benn, D. Benn, K. Benner, R. Bennett, E. Bennett, C. Bennett, J. Bennett, N. Bennett, D. Bennett, S. Bennett, A. Benoit, P. Benoit, D. Bensley, M. Benson, A. Benson- Bartko, J. Bent, A. Bentley, R. Bentley, I. Bentsianov, J. Berdan, C. Bereznicki, D. Berg, R. Berg, L. Berge, O. Bergeron, M. Bergeson, J. Bergeson, B. Bergley, J. Bergquist, J. Bergsma, C. Bergsma, D. Berlinguette, T. Bernhard, J. Bernier, K. Berreth, R. Berry, W. Berscht, D. Bershadsky, S. Bertelmann, G. Bertolin, J. Bertrand, A. Bertrand, B. Bertrand, M. Bertsch, B. Berube, R. Besinger, J. Best, C. Best, C. Betancur Pelaez, C. Bettany, T. Betteridge, S. Bettinson, W. Bewski, B. Beyer, J. Beytell, S. Bezpalchuk, J. Bezruchak, M. Bezugley, A. Bhadauria, A. Bhaduri, L. Bhamare, J. Bhangoo, H. Bhathal, H. Bhatia, K. Bhatt, R. Bhatt, J. Bhatt, V. Bhekare, J. Bianchini, L. Bianco, M. Bibars, A. Bibo, J. Bick, S. Biddle, T. Biddlecombe, C. Bieber, D. Bieber, D. Bielech, E. Bieleski, D. Biendarra, D. Biener, V. Biesinger, K. Biever, C. Biggin, M. Biggs, A. Bilal, D. Biles, B. Bill, L. Billard, T. Billard, J. Bilous, D. Bilston, W. Binda, M. Binder, B. Binns, R. Bintz, C. Bird, T. Bisbing, R. Bischoff, C. Bischoff, S. Bischoff, B. Bischoff, C. Bish, T. Bishop, H. Bishop, J. Bishop, K. Bishop, C. Bisschop, L. Bissell, C. Bisson, M. Bissonnette, D. Bittner, J. Bizuk, T. Bjerland, K. Black, R. Black, A. Black, C. Black, B. Black, V. Black, J. Black, D. Black, P. Blackburn, W. Blackburn, T. Blackett, R. Blackmore, K. Blackmore, T. Blackwell, A. Blacquiere, N. Blaik, D. Blain, G. Blain, K. Blair, D. Blair, A. Blair, L. Blair, A. Blake, J. Blake, D. Blake, L. Blake, P. Blakely, B. Blakney, J. Blanc, T. Blanchard, G. Blanchard, D. Blanchard, A. Blanchard, J. Blanche, R. Blanchett, K. Blanchette, U. Blanco, W. Blanco, G. Blanco, A. Blanco, L. Bland, S. Blaquiere, E. Blawat, S. Blaydes, K. Blencowe, J. Blesa, A. Blesa Gomez, N. Bligh, M. Blinkhorn, S. Blize, R. Blonar, R. Blondin, G. Blouin, P. Bluemke, J. Blume, J. Blundon, C. Blyan, C. Boadas Salazar, J. Bobbett, A. Bobrowski, H. Bocalan, D. Bochek, R. Bock, G. Boddy, J. Bodell, R. Bodell, S. Bodell, V. Boden, K. Bodnar, A. Bodnar, V. Bodnarchuk, J. Bodnarchuk, B. Bodner, G. Bodner, D. Bodoano, D. Boehmer, D. Boettcher, D. Boettger, M. Boggust, L. Boghici, B. Boguslaw, T. Bohach, A. Bohemier, J. Bohlken, B. Bohlken, N. Bohning, J. Bohorquez, J. Boire, J. Boissoneault, C. Boisvert, J. Boisvert, M. Boisvert, D. Bokota, R. Boksteyn, S. Bolduc, C. Bolger, G. Bolin, D. Bolster, B. Bolt, J. Bolt, G. Bolzon, S. Bond, K. Bond, T. Bond, N. Bond, G. Bond, E. Bondarenko, T. Bondaruk, N. Bonderoff, A. Bone, C. Bonebrake, A. Bonilla, E. Bonnefon, C. Bonogofski, A. Bonwick, T. Bonwick, S. Booker, R. Booker, J. Boomgaarden, A. Boone, B. Boone, C. Boos, K. Booth, B. Borbely, R. Bordeleau, K. Bordeleau, D. Borden, C. Borgel, C. Borgland, J. Borkowski, S. Borkowsky, M. Borlaza, N. Born, M. Born, D. Borowski Grimaldi, K. Borromeo, E. Borsini Marin, M. Borst, J. Borstel, K. Borysiuk, P. Borzel, J. Bosch, B. Bosch, S. Bosch, D. Bosch, J. Boschman, S. Bose, G. Bosma, N. Bosman, L. Bosoi, P. Bossel, A. Botha, H. Botha, K. Bothwell, J. Botterill, T. Bouchard, L. Bouchard, D. Bouchard, J. Bouchard Lacoste, T. Boucher, C. Boucher, K. Boudreau, J. Boudreault, K. Bougie, B. Boulton, J. Boulton, T. Bouma, J. Bounds, S. Bourassa, C. Bourassa, R. Bourassa, L. Bourassa, T. Bourassa, J. Bourgeois, C. Bourlon, D. Bourque, D. Bourquin, S. Bourrie, C. Boutier, M. Boutilier, D. Bouvier, S. Bouwer, K. Boven, C. Bowal, M. Bowal, C. Bowditch, J. Bowen, S. Bowers, D. Bowes, D. Bowey, J. Bowie, B. Bowie, M. Bowles, J. Bowman, K. Bowman, W. Bowman, N. Bowman, C. Bowman, E. Bown, W. Bowness, J. Boxer, D. Boyarski, R. Boyce, T. Boyce, S. Boychuk, J. Boyd, S. Boyd, L. Boyde, J. Boyde, C. Boyer, A. Boyer, R. Boyko, V. Boyko, N. Boyle, D. Boyle, L. Boyle, D. Bradbury, P. Bradley, B. Bradley, A. Bradley, P. Bradner, M. Brady, J. Brady, G. Brady, J. Bragg, L. Bragg, S. Braithwaite, T. Brake, N. Brake, J. Brake, S. Brake, J. Branderhorst, J. Brannick, E. Brant, D. Brant, B. Brant, P. Brar, C. Brassard, M. Brataschuk, K. Bratt, K. Brattebo, R. Brattston, C. Brausen, M. Brautigam, L. Bravo, K. Bravo, J. Brawn, T. Bray, A. Brazeau, J. Breau, W. Brebant, G. Brecht, M. Brecht, S. Bredy, D. Bredy, M. Breen, D. Breen, S. Breen, E. Brekke, B. Brekke, D. Bremner, M. Brennan, L. Brennan, J. Brenton, R. Brenton, L. Brenton, B. Brenton, T. Bresson, K. Brethour, T. Bretzer, R. Bretzlaff, S. Brewer, A. Brewer, J. Breytenbach, R. Brezinski, W. Briand, B. Bricker, M. Brideau, J. Bridger, D. Bridger, C. Bridger, J. Bridges, M. Brietzke, M. Briggs, G. Briggs, C. Briggs, J. Bright, C. Brilling, L. Brinkworth, S. Brinson, S. Brinston, C. Brisebois, B. Britton, S. Britton, P. Britton, J. Brock, M. Brock, E. Brock, K. Brocke, M. Brodbin, A. Broderick, D. Broderick, S. Broderson, D. Brodziak, E. Broidioi, K. Bromley, J. Bronkhorst, G. Bronson, D. Brooks, J. Brooks, R. Brooks, S. Broomfield, G. Brophy-Maclean, K. Brosowsky, C. Brousseau, C. Brow, B. Brown, M. Brown, G. Brown, C. Brown, D. Brown, W. Brown, R. Brown, L. Brown, A. Brown, K. Brown, N. Brown, J. Brown, T. Brown, P. Brown, E. Brown, S. Brown, D. Brownrigg, R. Bruce, T. Bruce, J. Bruce, L. Bruchanski, A. Brucker, R. Brue, K. Bruggencate, F. Brugger, V. Brule, S. Brulotte, N. Brummitt, R. Brundige, D. Brundige, K. Bruner, M. Brunet, A. Brunet, M. Brushett, R. Bryan, P. Bryant, L. Bryant, B. Bryant, R. Bryant, T. Bryant, G. Brydges, E. Bryenton, H. Bryenton, B. Bryks, J. Bryla, M. Bryson, S. Bryson, G. Buchan, P. Buchanan, M. Buchinski, J. Buck, D. Buckley, G. Buckshaw, T. Budd, N. Budden, B. Budgell, R. Budzen, R. Bueckert, S. Bugden, W. Bugiak, N. Buhler, J. Buholzer, S. Bukhari, S. Bulger, C. Bull, T. Bullen, R. Bullen, K. Bulley, I. Bulloch, J. Bullock, D. Bumstead, G. Bungay, L. Bungay, Q. Bunten-Walberg, B. Bunz, D. Burak, T. Burchenski, A. Burden, K. Burden, J. Burdett, D. Burgess, B. Burk, T. Burkart, G. Burkart, S. Burke, L. Burke, G. Burkhart, P. Burness, J. Burnett, R. Burnham, J. Burnouf, J. Burns, L. Burns, R. Burris, C. Burroughs, D. Burry, B. Burry, S. Burry, D. Bursey, A. Burt, K. Burton, M. Burton, J. Burton, T. Burton, N. Burton, W. Burton, R. Burton, G. Burton, R. Busato, K. Bush, D. Bushey, J. Bushfield, T. Bushie, N. Bussiere, J. Bustamante, M. Butchart, T. Butler, D. Butler, J. Butler, I. Butler, R. Butler, M. Butler, C. Butler, D. Butlin, S. Butt, M. Butt, K. Butt, R. Butt, T. Butt, Q. Butt, W. Butt, B. Butt, M. Buttigieg, R. Butts, K. Butts, P. Buxton, W. Bykewich, J. Byrne, M. Byrne, T. Byrnell, J. Byrtus, I. Byvald, L. Cabatuando, A. Cabral, M. Cabrera, J. Cachene-Clark, T. Cadieux, B. Cain, A. Caines, H. Cairns, E. Caissie, W. Calabio, L. Calder, J. Caldwell, P. Caldwell, C. Caleffi, D. Callander, C. Callihoo, P. Callin, R. Calliou, M. Camargo, N. Cambridge, S. Cameron, C. Campbell, P. Campbell, A. Campbell, B. Campbell, D. Campbell, G. Campbell, K. Campbell, S. Campbell, E. Campbell, W. Campbell, N. Campbell, N. Campeau, W. Campeau, A. Campeau, A. Campos, M. Canchica, G. Cane, R. Canelon Oyarzabal, J. Cannell, J. Canning, R. Canning, M. Canning, C. Canning, J. Cannon, E. Cantlon, J. Cantwell, M. Cao, G. Caouette, A. Caouette, D. Caouette, K. Cap, A. Capadosa, M. Capitaneanu, L. Cappelle, M. Capstick, B. Carabin, G. Carde, A. Cardenas, L. Cardenas Schulz, R. Cardinal, F. Cardinal, W. Cardinal, L. Cardinal, M. Carew, J. Carey, W. Carey, T. Carleton, J. Carleton, D. Carleton, K. Carlos, F. Carlos Sanchez, W. Carlson, J. Carlson, D. Carnes, J. Caron, D. Caron, R. Caron, A. Caron, S. Caron, G. Carpo, J. Carr, C. Carr, D. Carr, L. Carranza, V. Carrasco Rueda, T. Carrier, M. Carrier, M. Carroll, J. Carroll, S. Carroll, I. Carroll, D. Carroll, C. Carruthers, C. Carsh, C. Carson, B. Carson, E. Cartaya, D. Carter, E. Carter, J. Carter, R. Carter, K. Carter, I. Carter, N. Carter, S. Carter Hicks, C. Cartier, X. Cartron, J. Cartwright, S. Carty, D. Casavant, G. Case, P. Cashin, E. Cassell, B. Cassell, D. Cassidy, T. Cassidy, J. Cassivi, L. Casson, F. Castellanos, A. Castillo, K. Castle, C. Castro, J. Castro, A. Cater, N. Catley, L. Catto, J. Cauchie, L. Caul, D. Cavacciuti, N. Cavanagh, A. Cavanagh, D. Cavers, J. Cawthorpe, J. Cayabo, C. Cayer, D. Cazabon, C. Celis, B. Cembrowski, M. Cenon, A. Centeno, S. Cervantes, B. Chaba, D. Chadwick, A. Chafe, R. Chaisson, A. Chaisson, S. Chakraborty, S. Chakravarty, M. Chalaturnyk, A. Chalifoux, C. Chalifoux, M. Chalmers, A. Chamanara, T. Chambers, C. Chambers, K. Champagne, L. Champagne, R. Chan, A. Chan, I. Chan, D. Chan, V. Chan, J. Chan, C. Chan, T. Chan, L. Chan, S. Chan, M. Chan, A. Chaney, K. Chang, J. Chanski, T. Chantler, C. Chaon, H. Chaouach, M. Chapman, K. Chapman, S. Chapman, B. Chapple, W. Charanek, S. Charette, J. Charlebois, D. Charlish, J. Charlton, Y. Charniauski, L. Charrois, C. Char-

10,180

STRONG

DIVERSITY. TALENT. EXPERTISE.

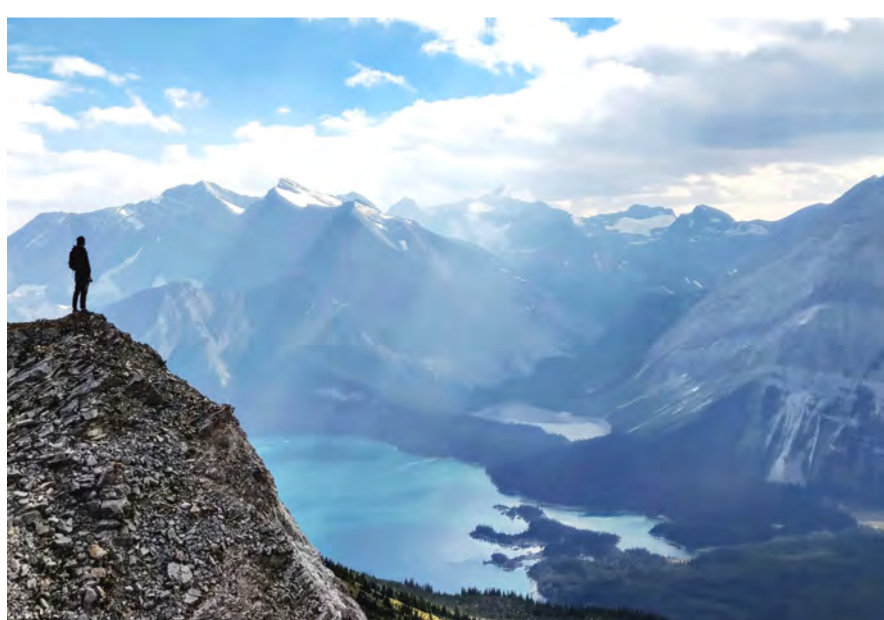
To develop people to work together to create value for the Company's shareholders by doing it right with fun and integrity.

trand, R. Chartrand, P. Chase, M. Chatman, A. Chatman, A. Chatterjee, M. Chaudhry, D. Chauvet, J. Chaval, S. Chavda, D. Chavez, M. Chawla, T. Chayko, M. Chayko, P. Chaytor, C. Chaytor, M. Chechile, W. Cheladyn, H. Chen, Z. Chen, X. Chen, T. Chen, J. Chen, C. Chen, B. Chen, N. Cheng, C. Cheng, J. Cheng, D. Chenier, N. Cheraghi, Z. Cherniawsky, M. Chernichen, T. Cherry, D. Chervenkov, O. Chervyakova, J. Chester, B. Chester, D. Chetcuti, W. Cheung, K. Cheung, A. Cheung, B. Cheyne, B. Chhualsingh, F. Chiasson, K. Chichak, B. Chichak, D. Chick, T. Chick, B. Chicoine, D. Chidley, K. Chikowski, S. Childs, D. Childs, K. Chilibeck, D. Chilver, Y. Chin, A. Chin, S. Chin, C. Ching, R. Chipchura, T. Chipiuk, M. Chiplin, A. Chisholm, B. Chisholm, T. Chisholm, T. Chislett, P. Chiu, R. Chmilar, J. Chohan, D. Choi, J. Cholka, N. Chondropoulos, R. Chong, B. Chopping, B. Chorney, M. Chorney, C. Chornohos, C. Chorostecki, S. Choudhury, K. Chow, C. Chow, A. Chow, R. Chowdhury, S. Chowdhury, G. Choy, J. Choy, A. Chretien, B. Christensen, T. Christensen, L. Christensen, R. Christensen, R. Christian, J. Christian, N. Christian, S. Christiansen, D. Christianson, M. Christianson, R. Christie, S. Christie, D. Christie, T. Christie, J. Chrobot, T. Chu, A. Chu, C. Chua, R. Chubaty, G. Chubbs, R. Chuckrey, D. Chudobiak, V. Chui, H. Chung, H. Church, N. Churchill, J. Churchill, D. Churchill, C. Churchill, G. Churchill, J. Churko, D. Chute, K. Chychul, O. Chyon, V. Cimon, K. Cisse-Banny, W. Clapperton, D. Clapperton, T. Clare, S. Claringbull, J. Clark, R. Clark, C. Clark, A. Clark, T. Clark, M. Clark, K. Clark, W. Clarke, S. Clarke, J. Clarke, R. Clarke, L. Clarke, B. Clarke, T. Clarke, K. Clarke, M. Clarke, W. Clarkson, D. Clarkson, C. Clarkson, S. Clavette, G. Clegg, T. Clelland, J. Clelland, R. Clemit, R. Clemmer, J. Clevenger, K. Climaco, C. Closs, Z. Closter, A. Clouston, J. Clouter, R. Cloutier, J. Clowater, G. Clowe, M. Cnossen, R. Coates, J. Coates, T. Coates, E. Cobaj, C. Cobaleda, D. Coburn, M. Cochet, J. Cochrane, B. Cochrane, E. Cochrane, D. Cockerill, F. Codd, E. Code, C. Codner, K. Codner, A. Codner, R. Coen, J. Coers, B. Colaco, L. Colborne, M. Colbourne, P. Cole, C. Cole, M. Cole, A. Cole, B. Cole, M. Coles, L. Collard, P. Colley, D. Collicutt, M. Collie, G. Collings, M. Collins, N. Collins, S. Collins, B. Collins, O. Collins, R. Collins, J. Collins, C. Collinson, C. Colliou, A. Collison, G. Collison, A. Collyer, R. Colnar, E. Comeau, R. Comer, J. Commance, K. Compagnon, W. Compagnon, M. Compton, C. Compton, Q. Conacher, M. Connell, E. Connell, A. Connell, M. Connellan, K. Conner, G. Connors, D. Conrad, B. Conroy, S. Constant, M. Conway, D. Conway, D. Conybeare, D. Cook, S. Cook, N. Cook, J. Cook, K. Cook, L. Cook, P. Cook, G. Cook, C. Cook, J. Cooke, G. Cooke, L. Cooke, A. Cookson, L. Cookson, K. Cookson, J. Coolen, H. Coolidge, K. Coombs, J. Coombs, L. Coonan, C. Cooper, M. Cooper, J. Cooze, C. Copeland, N. Copeland, R. Copland, R. Coppard, M. Coppola, D. Corbett, N. Corbett, N. Corbiere, F. Corbin, J. Corcoran, E. Corcoran, F. Cordingley, M. Corell, E. Coreman, C. Corkish, S. Cormier, I. Cormier, V. Cornejo, R. Cornish, D. Cornish, S. Correll, C. Corrigan, R. Corrigan, D. Corrigan, D. Corriveau, C. Corry, P. Corticelli, C. Corzo De Canchica, D. Cosby, G. Cossani, S. Costello, H. Costello, J. Costello, J. Costigan, G. Cote, C. Cote, E. Cote, J. Cote, B. Cote, A. Cote Simard, E. Cotten, L. Cottreau, S. Coulibaly, L. Coulibaly, D. Coull, J. Courchene, R. Courchesne, B. Courtney, T. Courtney, G. Courtney, P. Courtoreille, S. Courtoreille, T. Courtoreille, D. Courts, P. Cousin, J. Cousins, M. Cousins, T. Coutney, P. Covell, K. Cowan, J. Cox, K. Cox, R. Cox, G. Cox, B. Cox, E. Cozicor, N. Crabb, W. Crabtree, R. Craft, D. Craig, R. Craig, G. Craig, P. Craig, C. Craig, H. Craigie, J. Cram, K. Cramb, S. Cramb, P. Cramb, S. Cramm, M. Crane, A. Crawford, H. Crawley, J. Crawley, G. Crayford, N. Cressey, L. Cressman, R. Crichton, P. Crisby, J. Critch, C. Critch, N. Critch, D. Crittall, A. Critten, W. Crockford, A. Croft, S. Croft, G. Crooks, A. Crosby, T. Crosley, D. Crosley, B. Cross, R. Cross, C. Cross, T. Cross, S. Croteau, T. Crouser, K. Crouser, K. Crowder, C. Crowe, S. Crowe, D. Crowle, E. Crowley, P. Crozier, D. Crum, L. Cruttenden, J. Cruz, A. Csabay, S. Cseke, P. Cudak, E. Cuello, H. Cui, J. Cullen, M. Culligan, E. Cullimore, A. Cunanan, S. Cunningham, D. Cunningham, A. Cunningham, E. Cupac-Cingel, J. Curran, S. Curran, S. Currie, R. Currier, B. Curry, K. Cursley, K. Cusack, R. Cusson, M. Cusson, D. Cutler, S. Cutler, J. Cutler, J. Cuu, J. Cuzovic, D. Cyr, S. Cyr, G. Cyr, C. Cyr, J. Cyrenne, D. Cyron, K. Cytko, P. Czajko, M. Czerwinski, R. Czerwony, K. d'Abadie, V. Daboin, A. Dabrowski, M. Dacillo-Basallajes, F. Dadashov, R. Dadey, M. Dadi, G. Dafoe, J. Dafoe, W. Dagley, C. Dahl, A. Dahmani, J. Dai, J. Daigle, B. Daignault, P. Dale, D. Dalgarno, L. Dalgetty-Rouse, G. Dallaire, J. Dallaire, G. Dalley, B. Dalley, M. Dalton, G. Daly, G. Dalziel, R. Damer, D. D'Amour, S. Dams, E. Dana, C. Danaher, T. Danbrook, A. Danbrook, W. Danchak, S. Daneshmand, J. Daniels, T. Daniels, D. Danilkewich, G. Dann, I. Dantiwala, C. Danyluk, P. Danyluk, D. Daraban, S. Darai, M. D'arcangelo, A. Dareichuk, V. Darel, E. Dargatz, C. Daria, M. Darling, S. Darrah, K. Darvill, D. Das, F. Daub, J. Daugherty, M. Dave, D. Dave, C. Davey, P. David, G. David, L. David, J. Davidson, S. Davidson, T. Davidson, M. Davidson, G. Davidson, N. Davies, L. Davies, J. Davies, C. Davies, S. Davies, D. Davies, M. Davies, C. Davis, T. Davis, K. Davis, H. Davis, R. Davis, J. Davis, S. Davis, E. Davison, P. Davison, B. Davis-Sorochuk, S. Dawe, L. Dawe, D. Dawe, K. Dawe, J. Dawson, R. Dawyduk, T. Day, S. Day, D. Day, J. Daye, V. Daze, M. de Chavez, M. De Ga, H. de Graaf, R. De Jesus, R. de Jong, R. De Leeuw, B. De Lorenzo, J. de Luna, D. De Oliveira, V. de Ruiter, R. de Ruiter, A. De Sousa, C. de Wit, B. de Witt, B. Deacon, K. Deacon-Rosamond, I. Deaconu, P. Deagle, R. Dean, A. Dean, M. Dean, A. Dearaway, G. Dearden, C. Deaver, J. deBalinhard, T. Debler, R. Debnath, S. Debnath, D. Deboer, R. deBoer, W. DeBona, S. DeBruycker, P. DeBusschere, D. Dechaine, J. Dechaine, R. Dechaine, P. Dechant, R. Dechesne, K. Decker, D. Decker, B. Decker, J. Decker, R. Decker, J. Decoeur, D. Decoine, W. Dedam, E. Dee, N. Deeney, L. Deep, M. Deering, L. Defoort, S. DeFord, M. Degenstien, S. Degroot, B. DeHaan, A. Deibert, E. Deisting, R. DeJong Dyck, B. DeLair, L. Delaire, I. Delaney, P. Delany, E. DeLaRonde, J. Delaurier, A. Delavarmoghaddam, C. Delawski, M. deLisser, M. Dell, M. DelMastro, M. Delorme, R. Demarsh, B. Demirdal, C. DeMone, R. DeMott, S. Dempsey, G. Dempsey, M. Denault, D. Deneau, G. Denney, S. Dennis, D. Dennison, S. Denny, C. Denslow, J. Dent, S. d'Entremont, H. Derakhshan, D. Derbyshire, J. Derix, K. Derkowski, B. Derochie, M. Derry, G. Desai, C. Desai, P. Desai, R. Desai, D. Desai, A. Desai, S. Desai, M. Deschambeau, T. Deschamps, D. Deschenes, A. Desharnais, V. Deshpande, D. Desjardins, C. Desjardins-Knowlden, G. Desjardins-Knowlden, C. Desmarais, S. Desmarais, J. Desnoyers, M. Desormeau, L. Despins, D. Dessario, M. Detta, P. Deutcheu, K. Deutsch, A. Deutscher, S. Deval, B. Devereux, L. Devey, N. Devlin, J. DeVries, T. Dew, J. Dewar, T. Dewar, C. Dewar, T. Dewhurst, K. Deyaegher, M. Deyan, H. Dhaliwal, G. Dhaliwal, M. Dhaliwal, J. Dhaliwal, P. Dhalwala, B. Dhanesha, P. Dhanjal, K. Dhanoa, J. Dharamsi, M. Dhariwal, K. Diallo, B. Diamond, M. Diaz, D. Diaz, L. Diaz, A. Dick, R. Dicken, K. Dickey, A. Dicks, J. Dicks, E. Dicks, C. Dickson, G. Dickson, A. Didenko, J. Diederich, S. Dietrich, P. Diggle, S. Diggle, M. Diiorio, I. Dikau, E. Dillabough, A. Dillabough, R. Dillman, K. Dilts, A. Dimapilis, L. Dimion, Y. Ding, X. Ding, M. Dingley, G. Dingwell, H. Dinn, R. Dinn, K. Dinney, P. Dion, S. Dionne, M. D'Ippolito, R. Diputado, S. Dirk, M. Dirk, T. Ditchburn, E. Ditzler, A. Dixit, T. Dixon, D. Dixon, C. Dixon, R. Dixon, D. Dixson, K. Do, M. Doak, W. Dobchuk, G. Dobek, C. Dobek, C. Dobson, L. Dobson, S. Dobson, R. Docksteader, R. Dodd, L. Dodd, R. Dodunski, R. Doering, J. Doetzel, A. Doherty-Snelgrove, K. Doiron, J. Doiron, G. Dolan, P. Dolan, S. Dolhanty, K. Doll, D. Dolynchuk, D. Doma, G. Doma, G. Domalain, R. Domazet, B. Dombrova, M. Dombrova, D. Domin, K. Donahue, K. Donald, E. Donaldson, S. Donaldson, R. Donaleshen, M. Dong, J. Donohoe, J. Donovan, N. Donovan, C. Doo, J. Doonanco, S. Dorer, A. Dorey, J. Dorusak, A. Dosanjh, J. Dosman, I. Dosso, M. Doty, M. Doucet, D. Doucette, J. Douglas, J. Doust, T. Dove, R. Dow, J. Dowd, A. Dowd, E. Dowell, J. Dowhay, P. Downes, P. Downey, D. Downey, J. Downey, A. Downey, A. Downs, R. Doyer, L. Doyle, G. Doyle, S. Doyon, R. Drainville, S. Drake, P. Drapeau, W. Draper, T. Draper, K. Draper, G. Draper, J. Dreaddy, S. Drebit, K. Dreger, C. Drescher, D. Dresser, D. Dressler, C. Drevant, D. Drew, B. Drew, A. Driemel, A. Drier, T. Driscoll, B. Driscoll, R. Drolet, E. Drolet, R. Drosu, S. Drouin, C. Drover, A. Drover, J. Drover, R. Drover, B. Drover, R. Drummond, C. Drury, D. Drury, S. Drysdall, P. D'Souza, V. D'Souza, H. D'Souza, C. Du, M. Du, M. Du Preez, P. Duan, C. Duane, C. Duarte, M. Dube, T. Dube, R. Dube, B. Dube, N. Dube, A. Dubetz, T. Dubie, J. Dubois, G. Dubois, L. DuBois, J. Dubuc, D. Duby, C. Dubyk, M. Ducey, R. Ducey, S. Ducharme, R. Ducharme, J. Duchscherer, A. Duczek, P. Duda, S. Dudley, L. Dueck, G. Duff, C. Duffett, D. Duffy, K. Duford, E. Dufour, P. Dugay, C. Duggan, W. Duggan, D. Duguid, A. Duhaime, E. Dulay, C. Dumais, J. Dumas, T. Dumba, O. Dumitrache, G. Dumont, Y. Dumont, C. Dunbar, S. Duncan, H. Duncan, J. Duncan, B. Duncan, R. Duncan, S. Dunn, P. Dunn, R. Dunn, J. Dunn, D. Dunn, B. Dunn, J. Dunnigan, C. Dunsmore, J. Dunsmuir, D. DuPerrier, D. Dupuis, K. Dupuis, J. Durdle, A. Durham, J. Duris, K. Durocher, J. Dutchak, J. Duthie, R. Duthie, O. Dutka, R. Duval, N. Duval, M. Dux, C. Duynisveld, B. Dwyer, R. Dwyer, C. Dwyer, D. Dybala, J. Dybala, A. Dyck, C. Dyck, J. Dyer, E. Dyjur, L. Dyke, B. Dzirasah, K. Dzwonek, B. Eagle, J. Eagleson, M. Eamer, G. Earl, R. Earl, J. Easthope, J. Eastman, B. Eastman, J. Easton, K. Eberle, R. Ebuna, G. Ecker, D. Edgington, A. Edmunds, A. Edoukou, A. Edugyan, T. Edwards, P. Edwards, D. Edwards, J. Edwards, T. Eeuwes, S. Effiong, A. Effray, T. Egan, L. Egeland, R. Eggen, C. Eggleton, A. Egresits, C. Ehnes, C. Ehresman, I. Eichelbaum, M. Eidet, N. Eifler, B. Eitzen, D. Ekdahl, J. Ekelund, S. Ekstrom, R. Elaschuk, I. Elgarni, M. Elgarni, M. El-Harakeh, D. Elia, T. Elias, M. Elias Neira, C. Elkink, K. Elladen, P. Ellingson, D. Elliott, B. Elliott, S. Elliott, J. Elliott, R. Elliott, H. Elliott, K. Ellis, D. Ellis, S. Ellis, P. Ellison, K. Ellsworth, E. Ellsworth, C. Ellsworth, A. Elmobarik, M. Elms, O. El-Sayed, E. Elson, J. Elson, T. Ely, C. Emberley, V. Embleton, H. Emery, C. Emmett, G. Emmott, J. Engel, K. Engelking, J. Engen, T. Engler, R. Engler, J. English, M. Enns, R. Enns, J. Entz, R. Ephgrave, T. Epp, J. Epp, J. Erasmus, S. Erb, D. Ereaut, B. Eresman, D. Eresman, C. Erfle, B. Erickson, J. Erickson, S. Erickson, M. Erl, M. Ernst, P. Ersh, C. Erskine, D. Ertmoed, W. Esau, P. Escalona, L. Eshaq, O. Esharefasa, N. Eskandar, G. Eskandari, M. Espejo, R. Espenido, L. Espie-Winsor, A. Espindola, M. Espiritu, R. Esslemont, B. Estey, O. Estrada, J. Etcheverry, D. Etherington, S. Etherington, G. Etti, J. Eunson, D. Evans, J. Evans, T. Evans, A. Evans, R. Evans, R. Evasco, K. Evdokimoff, L. Eveleigh, S. Eveleigh, J. Eveleigh, A. Everson, C. Eves, J. Ewald, J. Ewen, J. Eyma, Z. Ezeh, V. Ezeronye, L. Faber, T. Fabrick, R. Faechner, B. Fagan, J. Fahim, E. Faichney, B. Fairbairn, S. Fairfield, M. Faiz, K. Falconer, S. Fallahi, M. Fallen, Y. Fang, D. Fanning, H. Farah, S. Farhan, A. Faria, H. Farid, S. Farn, D. Farney, M. Farokhshad, A. Farquhar, G. Farrell, T. Farrell, J. Farrell, D. Farrell, T. Farrer, R. Farrer, S. Farrow, D. Farrow, S. Faruqi, W. Faryna, K. Fast, B. Fast, R. Fast, S. Fast, A. Faucher, S. Faucher, C. Faucher, J. Faulkner, R. Faustini, E. Fauth, C. Fayant, R. Fayant, M. Fear, R. Featherstone, S. Feaver, T. Feaver, N. Fecteau, M. Federucci, D. Fedoruk, E. Fedossova, C. Fedun, M. Fedyk, T. Fedyna, E. Feely, J. Feener, D. Fehr, B. Feil, J. Feland, D. Feland, J. Feldmeier, D. Feller, R. Fells, R. Feltham, E. Fender, M. Feng, K. Fenrich, L. Fentie, A. Ferbey, A. Ferdjallah, K. Ferdous, S. Ferenc, K. Ference, L. Ference, S. Ferguson, L. Ferguson, M. Ferguson, R. Ferguson, C. Ferguson, B. Ferguson, H. Ferguson, M. Ferhatbegovic, B. Fernandes, J. Fernandez, A. Fernandez, E. Fernandez, L. Fernandez Exposito, S. Fernandez-Trujillo, N. Ferrer, M. Ferris, M. Ferron, M. Ferry, R. Fersch, S. Fetinko, L. Fetter, C. Fetter, D. Fewer, J. Fewer, V. Fiacco, C. Fibke, D. Fichter, C. Ficko, B. Field, C. Field, M. Fielden, W. Fielding, J. Fielding, K. Fielding, B. Fifield, C. Filewych, C. Filgate, M. Filipponi, D. Fillier, T. Fillmore, B. Finch, D. Findlay, N. Findlay, T. Findlay, J. Findlay, A. Fink, B. Finlayson, J. Finley, D. Finnamore, C. Finnebraaten, K. Finnerty, R. Finney, B. Finnie, T. Finnigan, K. Finnigan, E. Finnigan, W. Fischer, C. Fischer, L. Fischer, J. Fish, D. Fisher, C. Fisher, L. Fisher, B. Fitzgerald, J. FitzGerald, C. Fitzgerald, S. Fitzner, S. Fitzpatrick, R. Fitzpatrick, K. Flack, M. Flahr, J. Flamont, C. Flamont, D. Flannery, B. Fleck, M. Flegel, P. Flek, D. Fleming, P. Fleming, S. Fleming, T. Fleming, A. Fleming, N. Flemming, J. Fletcher, L. Fletcher, A. Fletcher, R. Flett, P. Flett, B. Flier, T. Flight, B. Flockhart, I. Florea, B. Flottvik, J. Floyd, J. Fluney, B. Flynn, R. Flynn, C. Flynn, J. Flynn, S. Flynn, C. Fogal, K. Foisy, D. Fokema, S. Foline, R. Folmer, P. Foming, G. Fondjo, Y. Fong, A. Fontaine, D. Fontaine, G. Fontaine, R. Fontaine, B. Foord, L. Foote, R. Foran, D. Forbes, M. Forbes, D. Forbister, A. Forcade, G. Ford, R. Ford, W. Ford, T. Ford, J. Foreman,

B. Forest, L. Forget, C. Forget, L. Forman, D. Forman, C. Formanek, R. Formanek, T. Fornwald, A. Forrest, G. Forrester, B. Forrester, B. Forrister, J. Forsberg, B. Forshner, K. Forshner, M. Forster, S. Forster, H. Forte, A. Fortier, C. Fortier, D. Fortin, J. Forward, B. Foss, S. Foss, D. Fosseneuve, D. Foster, S. Foster, B. Foster, K. Foster, V. Foster, C. Foster, D. Fotty, C. Fotur, O. Fouego, A. Fougere, K. Foulds, R. Foulkes, J. Fountain, G. Fountain, B. Fouracres, H. Fowell, G. Fowler, J. Fowler, J. Fox, D. Fox, S. Foxton, M. Foxton, K. Fraboni, F. Frame, C. Frampton, J. France, R. France, C. France, M. Francescone, D. Franche, O. Franchi, D. Francis, N. Franck, M. Franco, D. Frank, C. Frank, A. Frankiw, P. Fransen, K. Franson, W. Franson, S. Franssen, R. Frasch, C. Fraser, K. Fraser, B. Fraser, R. Fraser, G. Fraser, M. Fraser, L. Fraser, J. Frayn, K. Frazer, G. Freake, C. Freake, B. Frechette, S. Freckelton, G. Freeman, M. Freeman, A. Freeman, U. Freiberg, E. Frejoles, R. French, B. Frenette, J. Frese, K. Freyman, K. Friedrich, F. Friesen, K. Friesen, R. Friesen, M. Friesen, N. Friesen, D. Friesen, J. Friesen, H. Friesen, A. Frizorguer, D. Frizzell, C. Froc, J. Froc, C. Frosini, S. Froude, C. Froude, A. Fry, T. Fryer, X. Fu, N. Fucile, R. Fudge, B. Fudge, C. Fudge, L. Fudge, K. Fujimoto, D. Fukushima, W. Fulkerson, J. Fuller, D. Fung, J. Fung, S. Fung-Yau, R. Funk, K. Funk, C. Funk, M. Funke, J. Furey, M. Furey, A. Furgiuele, L. Furlong, A. Furlong, T. Furuya, C. Fuster, A. Fyith, J. Gaberel, A. Gabr, K. Gabrielson, D. Gabruck, K. Gadzala, R. Gaetz, L. Gaffney, N. Gafuik, J. Gage, A. Gage, D. Gagne, C. Gagne, J. Gagnon, D. Gagnon, K. Gagnon, S. Gagnon, E. Gagnon, R. Gagnon, W. Gail, B. Galbraith, P. Gale, M. Galea, J. Galey, R. Gallagher, R. Gallant, M. Gallant, F. Gallant, J. Galliott, S. Gallo, M. Gallon, J. Galotta, W. Gamache, B. Gamble, D. Gamblin, C. Gamboa, L. Gamboa, F. Gan, P. Gandhi, V. Gandhi, A. Gandhi, J. Ganie, D. Ganske, Y. Gao, V. Gapaz, M. Garbin, C. Garcia, A. Garcia, A. Garcia Varganova, D. Gardham, S. Gardiner, K. Gardiner, S. Gardner, E. Gardner, T. Gareau, J. Gareau, R. Gareau, R. Garg, V. Garg, K. Garland, A. Garneau, W. Garner, L. Garvey, C. Garzon, O. Gascoyne, E. Gashaw, M. Gates, J. Gatrell,

S. Gatt, S. Gauchan, G. Gaudet, C. Gaudet, F. Gaudet, W. Gaugler, L. Gauld, M. Gaulin, S. Gauthier, J. Gauthier, M. Gauthier, N. Gauthier, D. Gauthier, P. Gauthier, T. Gauthier, C. Gauthier, K. Gautschi, S. Gavronsky, T. Gaydos, G. Gayton, N. Gazdag, A. Gboko, B. Geall, S. Gebeyehu, J. Geddes, D. Geitz, C. Geldart, O. Gelowitz, M. Gemmell, M. Genereux, J. Genereux, C. Geng, G. Genge, B. Gensollen del Barco, P. Gentles, J. George, C. George, M. George, R. Georgescu, M. Georgescu, J. Georget, S. Geremia, J. Gergely, B. Gerke, G. Gerla, J. Gerlinger, M. Germain, S. Gerow, K. Gerow, M. Gervais, K. Gervais, E. Gervais, K. Gessner, T. Getchell, S. Getson, G. Getz, K. Getzinger, V. Ghadamyari, L. Ghasem Rashid, H. Ghazimoradi, M. Ghorbanie, J. Ghosh, E. Ghoubrial, D. Gibb, S. Gibbon, I. Gibbon, E. Gibbs, D. Gibson, J. Giebelhaus, S. Giefer, A. Gierach, C. Giesbrecht, T. Giesbrecht, J. Giesbrecht, E. Giesbrecht, D. Giesbrecht, J. Gigg, D. Giggs, G. Gilbert, J. Gilbert, C. Giles, M. Giles, T. Giles, S. Giles, J. Gilhang, D. Gill, S. Gill, J. Gill, L. Gill, M. Gill, N. Gill, R. Gill, K. Gill, J. Gillam, D. Gillan, J. Gillatt, S. Gillespie, M. Gillies, D. Gillingham, S. Gillingham, L. Gillingham, A. Gillingham, J. Gillingham, E. Gillingham, E. Gillis, E. Gillmore, M. Gillund, C. Gilman, K. Gilman, E. Gimenez, R. Gimoro, G. Gin, P. Gingras, T. Ginigeme, K. Ginter, M. Ginter, T. Ginther, K. Ginther, G. Girard, S. Girard, D. Girard, S. Girbav, J. Girouard, P. Girouard, D. Girouard, B. Gisby, M. Gisondo Crawford, E. Giuliani, J. Gladue, D. Gladue, G. Glanville, D. Glasco, A. Glasrud, M. Glavine, K. Glavine, R. Gleasure, R. Gleed, J. Glen, J. Glendenning, G. Glenn, D. Gliddon, D. Gloade, D. Glover, R. Glover, S. Glubish, R. Go, M. Go, J. Godin, B. Godkin, D. Godwin, L. Goerzen, C. Goeson, J. Gogol, C. Gogol, B. Gogowich, H. Goldberg, D. Golden, D. Goll, P. Goll, A. Goll, M. Gomaa, R. Goman, J. Gomez, E. Gomez, C. Gomez, C. Gomuwka, K. Gong, E. Gong, M. Gonzales, N. Gonzalez, Y. Gonzalez, I. Gonzalez, L. Gonzalez Lunden, P. Gonzalez Sierra, C. Good, P. Good, J. Goodair, A. Goodine, P. Goodman, J. Goodman, C. Goodman, W. Goodwin, B. Goodyear, J. Goodyear, R. Gooler, J. Gorai, K. Gordeyko, I. Gordon, S. Gordon, J. Gordon, T. Gordon, K. Gordon, L. Gordon, J. Gorgichuk, D. Gorrie, J. Gorski, R. Goshi, B. Gosse, R. Gosse, T. Gosse, D. Gosse, T. Gosselin, Y. Gosselin, B. Gosselink, C. Goudreau, C. Gough, A. Gould, J. Gould, B. Gould, T. Goulding, C. Goulet, P. Goulet, J. Gourlie, G. Gouthro, S. Gouthro, J. Gover, N. Govindarajan Prithivirajan, M. Goyal, A. Goyal, L. Goymer, J. Graca, N. Grace, R. Graf Jr., L. Graff, J. Grageda, P. Graham, M. Graham, G. Graham, S. Graham, R. Graham, D. Graham, T. Graham, J. Graham, C. Graham, R. Grandy, I. Grandy, J. Granger, B. Granger, C. Grant, R. Grant, A. Grant, L. Grant, T. Grant, M. Grant, J. Grant, S. Grant, A. Graup, B. Gravel, R. Graveline, R. Gravell, T. Graveson, S. Gray, C. Gray, R. Gray, B. Gray, D. Gray, J. Gray, N. Gray, L. Gray, C. Grayston, J. Greaves, G. Grebowski, A. Greeley, D. Green, G. Green, K. Green, T. Green, W. Green, C. Green, J. Green, M. Green, C. Greenawalt, D. Greenawalt, T. Greene, C. Greene, A. Greenfield, M. Greenwood, G. Greenwood, K. Greenwood, R. Greenwood, D. Greep, A. Grenier, J. Grenon, J. Greter, S. Grewal, A. Grewal, R. Grice, C. Grice, B. Grice, C. Grieder, R. Griemann, S. Grier, D. Grieve, R. Grieve, J. Griffin, M. Griffin, P. Griffin, E. Griffiths, K. Griffiths, J. Griffiths, H. Griffiths, A. Grise, R. Griswold, R. Groenen, E. Groom, M. Grosseth, W. Grotkowski, J. Grouchy, B. Grove, P. Grove, D. Grundner, D. Grzela, S. Gu, Y. Guan, V. Guardia-Mendez, C. Guay, D. Guay, C. Gudjonson, C. Gudmundson, S. Gue, P. Guedez, J. Guerin, D. Guevohe, M. Gueye, D. Guglielmin, A. Guillen, J. Guilmette, K. Guimond, R. Guinup, C. Guinup, A. Guitard, K. Gulamhusein, R. Gulati, S. Guled, R. Gulutzan, J. Gumbley, I. Gumbo, L. Gunnell, R. Gunning, I. Gunning, S. Gupta, A. Gupta, J. Gurba, M. Gurin, E. Gushue, J. Gushue, T. Gushue, T. Gusnowski, R. Gussen, C. Gustafson, M. Gustafson, G. Gustafson, J. Gustavson, P. Gut, M. Gutierrez, R. Gutknecht, G. Gygi, J. Gysler, D. Ha, T. Ha, E. Haag, B. Haahr, B. Haas, C. Haas, S. Haas, M. Haberoth, R. Hache, C. Hachey, K. Hachey-Lalonde, S. Hackett, E. Hadada, V. Haddad, L. Hadi, N. Hadskis, S. Haefliger, K. Hagan, T. Hagen, L. Hagg, A. Hagi-Memet, C. Hagstrom, K. Hague, S. Hahn, J. Haidasz, K. Haines, M. Haj Hamdan, A. Haj Hamdan, S. Hajar, S. Haji, L. Hale, C. Hales, D. Halewich, R. Haley, B. Haley, J. Halford, D. Halifax, J. Hall, B. Hall, T. Hall, R. Hall, S. Hall, M. Hall, C. Hall, S. Halland, S. Hallas, R. Halldorson, B. Hallett, G. Hallett, K. Halliday, O. Hallmark, R. Hallock, A. Halvorson, A. Hamad, C. Hambly, B. Hamborg, A. Hameed, K. Hameed, J. Hamel, P. Hamel, T. Hamel, J. Hamelin, D. Hamer, B. Hamer, S. Hamill, M. Hamilton, R. Hamilton, J. Hamilton, T. Hamilton, G. Hamilton, D. Hamilton, K. Hamilton, T. Hamitaj, T. Hamlyn, K. Hamm, A. Hammami, S. Hammel, M. Hammel, R. Hammer, D. Hammerlindl, S. Hammersley, J. Hammond, G. Hammond, B. Hammond, M. Hammond, C. Hampton, B. Hamrell, E. Han, G. Hanas, B. Hancock, E. Hancock, M. Hancock, B. Hancott, S. Hanlon, R. Hann, E. Hann, B. Hanna, R. Hansen, K. Hansen, D. Hansen, M. Hansen, J. Hansen, V. Hansen, A. Hansen, T. Hanson, L. Hanson, D. Hanson, K. Hanson, R. Hanson, J. Hanthorn, T. Hara, I. Harb, B. Harbin, L. Harder, K. Harder, P. Harding, C. Harding, J. Hardisty, G. Hardisty, B. Hardy, H. Hardy, F. Hardy, J. Hardy, A. Hare, A. Hargreaves, E. Harikumar, K. Harke, J. Harker, A. Harlal, L. Harley, D. Harley, E. Haroldson, B. Harpell, G. Harper, R. Harrietha, R. Harriman, W. Harris, M. Harris, S. Harris, J. Harris, B. Harris, C. Harris, A. Harris, C. Harrison, D. Harrison, N. Harrison, R. Harsany, D. Hart, C. Hartery, C. Hartl, P. Hartwick, A. Harty, J. Harty, A. Harvey, J. Harvey, D. Harvey, B. Harvey, R. Harvey, P. Harvey, S. Harvey, K. Harvey, M. Hashem, I. Hashi, H. Hashmi, K. Hasiuk, O. Hassan, B. Hassan, B. Hassen, C. Hassenrueck, J. Hatala, J. Hatcher, P. Hatt, G. Hatto, D. Haub, G. Haub, T. Hauger, R. Hauger, B. Haugo, J. Haukeness, W. Hausch, M. Havig, J. Haviland, T. Hawco, S. Hawco, D. Hawkins, S. Hawryliw, A. Hawthorne, S. Haxton, A. Hay, N. Hay, D. Hayashi, B. Hayden, C. Hayden, J. Hayden, J. Haydo, C. Hayduk, D. Hayes, P. Hayes, M. Hayes, K. Hayko, D. Haynes, J. Haynes, L. Haynes, T. Hayward, M. Hayward, R. Hayward, A. Hayward, J. Hazin, S. He, T. He, J. He, Y. He, T. Head, K. Head, M. Headrick, C. Heagy, B. Heagy, J. Heagy, A. Heale, L. Healy, K. Heard, B. Hearn, B. Heasley, B. Heath, A. Heath, L. Heath, C. Heath, D. Heath, B. Heatley, D. Heavens, J. Heavens, S. Heawood, T. Hebel, M. Hebert, J. Hebert, G. Hebert, B. Hebert, D. Hebert, B. Hebner, S. Heck, T. Heck, D. Heemeryck, C. Heffner, D. Hefford, C. Hehr, T. Heid, R. Heide, J. Heidebrecht, T. Heidebrecht, M. Heigl, R. Hein, C. Hein, F. Hein, J. Heinen, R. Heinrichs, B. Heise, R. Heiz, R. Helland, B. Helliker, R. Hellum, A. Hellyer, Q. Helm, D. Helms, R. Helyar, C. Hemington, D. Hemmelgarn, W. Hemminger, T. Hempel, B. Hemstock, R. Henderson, W. Henderson, S. Henderson, E. Hendrickson, K. Hendrickson, S. Hendry, K. Hennessey, A. Hennig, E. Henriquez, C. Henry, R. Henry, H. Henschel, D. Herauf, K. Herba, C. Herbst, W. Hergott, W. Herman, B. Herman, D. Herman, G. Hernandez, P. Hernandez, M. Hernandez, E. Hernandez, A. Hernandez, G. Herrebout, C. Herring, R. Herrington, D. Hertzsprung, M. Herzog, D. Heshka, R. Heska, A. Hess, M. Hessenbruch, B. Heugh, A. Heuthorst, J. Hevey, M. Hewitt, K. Hewitt, J. Hewitt, B. Hewitt, T. Hewitt, C. Hewlett, J. Hewlett, K. Hewlin, A. Heydari Gorji, C. Heywood, T. Hibberd, R. Hibbs, D. Hicke, P. Hickey, M. Hickey, R. Hickey, S. Hicks, B. Hicks, C. Hicks, R. Hicks, R. Hiebert, L. Hiebert, M. Hiemstra, T. Hiemstra, L. Hiendl, E. Hietanen, R. Higa, J. Higdon, R. Higgins, A. Higgins, J. Higgins, P. Higgitt, J. Higuerey De Sanchez, C. Hildahl, C. Hildebrand, J. Hill, C. Hill, T. Hill, D. Hill, H. Hill, K. Hill, R. Hill, D. Hillier, M. Hillier, R. Hillier, J. Hillier, S. Hillier, T. Hillier, C. Hills, T. Hills, D. Hillyard, T. Hilsendager, R. Hilton, B. Hindmarch, T. Hindson, K. Hingley, W. Hinkle, T. Hinks, K. Hinton, N. Hinze, M. Hird, K. Hirsch, D. Hiscock, F. Hiscox, D. Hitra, T. Hlewka, M. Ho, J. Ho, G. Ho, T. Ho, J. Hoare, W. Hobart, A. Hobbi, J. Hobbs, R. Hoda, O. Hodder, C. Hodder, G. Hodder, J. Hodder, D. Hodge, R. Hodgins, D. Hodgson, A. Hoeg, C. Hoeppner, N. Hoey, A. Hoey, N. Hoff, M. Hoffart, R. Hoffman, L. Hoffman, M. Hofstrand, G. Hogan, S. Hogan, R. Hogg, A. Hogg, M. Hogg, J. Hogg, B. Holaki, D. Holik, K. Holladay, A. Holland, M. Holland, K. Holland, C. Hollands, A. Hollebakken, I. Hollenbeck, P. Hollett, D. Holley, D. Hollingshead, J. Holloway, L. Holloway, G. Holloway, J. Hollowell, D. Holman, R. Holman, C. Holman, J. Holmes, T. Holmes, K. Holmes, M. Holmes, M. Holt, B. Holthe, C. Holthe, J. Holton, J. Holuk, D. Holwell, J. Holz, A. Holz, G. Homann, J. Hong, D. Honing, J. Hood, C. Hood, D. Hood, G. Hook, R. Hooper, J. Hooper, A. Hope, Y. Hopkins, S. Hopkins, P. Hopkins, N. Hopner, M. Hopp, C. Hopps, T. Hopwood, A. Hordy, D. Horlick, R. Horn, T. Hornberger, A. Hornseth, K.

Hornseth, B. Horobec, K. Horvath, R. Horvath, J. Horyn, K. Hosker, B. Hossain, M. Hossain, A. Hosseinpoor, T. Hou, S. Houck, L. Houghton, C. Houle, E. Houlihan, P. House, G. House, R. House, A. House, T. House, L. Houseman, G. Houston, K. Hovdebo, D. Howard, T. Howard, C. Howden, L. Howell, K. Howes, P. Howie, S. Howlader, J. Howse, M. Hoyles, T. Hoyles, R. Hoyt, D. Hoyt, B. Hoza, J. Hripko, D. Hrycak, T. Hrycay, B. Hryniw, A. Hrynkevych, R. Hrynyk, M. Hu, T. Hu, J. Hu, J. Huang, N. Huang, D. Huang, Q. Huang, M. Hubbers, R. Huber, G. Huber, W. Hubert, S. Hucal, J. Hucik, T. Huckabone, K. Huculak, W. Huddlestun, A. Hudkins, D. Hudson, P. Hudson, A. Hudson, L. Hudson, J. Hudson, S. Huebner, K. Huey, V. Huey, J. Huffman, J. Hughes, M. Hughes, B. Hughes, D. Hughes, E. Huh, R. Hui, M. Hulan, D. Hull, F. Hulme, M. Human, B. Human, S. Humberstone, R. Humphrey, J. Humphreys, S. Humphries, C. Humphries, A. Humphries, T. Humphries, M. Hunchak, I. Hundeby, M. Hundessa, M. Hung, M. Hunsperger, C. Hunt, M. Hunt, D. Hunt, S. Hunter, B. Hunter, D. Hunter, P. Hunter, L. Hunter, C. Hunter, K. Hunter, R. Hunter, W. Hunter, M. Hupchuk, J. Hurd, K. Hurd, C. Hurford, S. Hurley, G. Hurley, R. Hurtado, M. Hurtaj, R. Hurtubise, N. Husain, A. Hussain, S. Hussaini, G. Hussey, C. Hussynec, C. Hutchinson, A. Hutchinson, R. Hutchinson, D. Hutchinson, C. Hutchison, R. Hutscal, E. Hutton, D. Huxley, A. Huynh, M. Huys, S. Hwang, S. Hyatt, K. Hygard, A. Hymanyk, K. Hynes, T. Hynes, N. Hynes, J. Hynes, C. Hynes, A. Hynes, L. Hynes, E. Hynes, D. Hynes, M. Hynes, S. Hyrcha, P. Iannattone, L. Iannattone, G. Iannattone, R. Ibbotson, S. Ibrahim, K. Ibrahim, T. Idler, G. Iervella, H. Iftemie, N. Ilchuk, R. Imankulov, D. Imbeau, E. Imbery, W. Imeson, K. Imlach, M. Imran, S. Imrie, J. Inch, R. Inder, J. Inglis, C. Inglis, R. Inglis, G. Ingram, E. Ingram, C. Inkster, J. Inlow, B. Inman, C. Innes, M. Inscho, D. Ip, M. Ippolito, M. Iqbal, R. Irani, J. Ireland, R. Ireton, M. Irfan, J. Irons, K. Ironstand, R. Irvine, S. Irwin, J. Isaacs, C. Isaka, C. Isea Natera, B. Ish, H. Ishaque, U. Islam, A. Islam, F. Isley, O. Issa, J. Ivanova, B. Ivany, L. Iversen, C. Ives, J. Ivezic, C. Jabusch, M. Jackman, K. Jackson, S. Jackson, T. Jackson, R. Jackson, D. Jackson, G. Jackson, B. Jackson, C. Jackson, J. Jackson, J. Jacob, S. Jacob, K. Jacobs, C. Jacobs, M. Jacobs, J. Jacobs, K. Jacobson, M. Jacome, A. Jacques, A. Jacula, C. Jacula, M. Jacula, D. Jaeger, A. Jaffer, M. Jahangiri, R. Jahanshahi, V. Jain, M. Jaindl, K. Jaji, R. Jakher, R. Jakubowski, B. Jakulj, M. Jalali, G. Jaleel, M. Jama, L. Jama, S. Jamam, T. Jaman, D. Jaman, A. Jambrosic, W. James, S. James, D. James, K. James, R. James, T. James, T. Jamieson, R. Jamieson, S. Jamieson, J. Jamieson, D. Jamilano Jr., A. Janes, J. Janes, D. Janes, Z. Janosova-Den Boer, D. Jans, S. Jansky, T. Janusc, L. Janzen, M. Janzen, A. Janzen, L. Jardie, J. Jardine, S. Jardine, C. Jardine, N. Jaricha, C. Jarratt, K. Jarvis, B. Jarvis, J. Jarvis, K. Jaschke, J. Jaskow, S. Jaume, K. Jay, M. Jay-Rivas, N. Jeang, J. Jechow, W. Jellison, T. Jenkins, G. Jenkins, J. Jenkins, S. Jenniex, R. Jenniex, D. Jennings, V. Jensen, D. Jensen, T. Jensen, K. Jensen, B. Jensen, A. Jensen, L. Jensen, Q. Jensen, D. Jenson, K. Jentas, D. Jerkovic, M. Jeroncic, R. Jeronymo, T. Jervis, C. Jesso, M. Jesso, B. Jesso, T. Jessome, J. Jesson, S. Jevne, B. Jewell, C. Jezowski, P. Jia, S. Jiang, N. Jiang, Z. Jiang, Y. Jiang, R. Jimeno, X. Jing, P. Jingar, K. Jivraj, R. Jivraj, D. Joa, M. Joarder, P. Jobin, N. Jobson, K. Jochaud du Plessix, J. Jocksch, D. Jodoin, L. Jodoin, G. Joe, J. Joffre, G. Johal, I. Johanson, K. Johansson, J. John, T. Johns, D. Johnson, A. Johnson, B. Johnson, G. Johnson, K. Johnson, N. Johnson, J. Johnson, I. Johnson, M. Johnson, T. Johnson, C. Johnson, R. Johnson, M. Johnston, H. Johnston, D. Johnston, N. Johnston, R. Johnston, L. Johnston, A. Johnston, C. Johnstone, E. Johnstone, R. Johnstone, G. Johnstone, S. Johnstone, D. Johnston-Watson, J. Jonasson, C. Jones, R. Jones, E. Jones, B. Jones, M. Jones, G. Jones, D. Jones, K. Jones, A. Jones, L. Jones, V. Jones, N. Jongkind, P. Joo, J. Jorawsky, M. Jordan, D. Jordan, C. Jorgensen, B. Jorgensen, D. Jorgensen, M. Jorgensen, L. Jorgenson Donahue, A. Jose, P. Joseph, V. Joseph, D. Joseph, A. Joshi, H. Joshi, U. Joshi, T. Joshi, S. Joshua, S. Josselyn, R. Jost, M. Jovic, D. Jowsey, L. Joy, M. Juanerio, R. Jubinville, T. Juett, K. Juhasz, A. Junaid, S. Jung, J. Jung, C. Jungen, R. Jungkind, G. Junio, C. Jurgenliemk, K. Jurouloff, K. Juustila, T. Kabyn, A. Kachra, C. Kada, L. Kada, T. Kadi, T. Kadikoff, L. Kadutski, G. Kadylo, C. Kaglea, A. Kaid, M. Kaid, G. Kailas, K. Kajorinne, H. Kakadiya, M. Kakooei, S. Kalbag, V. Kalbag, O. Kalinchuk, D. Kalinowski, J. Kallis, A. Kalmet, D. Kalynchuk, A. Kamate, B. Kamath, A. Kamieniak, G. Kamon, S. Kanarek, A. Kandasamy, S. Kandulva Chakrapany, J. Kane, S. Kane, L. Kane, K. Kang, N. Kang, Z. Kanji, R. Kanomata, J. Kanzig, P. Kapadia, S. Kapeluck, M. Kapp, Y. Karayan Moosafi, P. Karimi, R. Karlowsky, J. Karlson, S. Karlstrom, T. Karnes, M. Karpan, C. Karpan, C. Karpiak, K. Kartushyn, D. Kary, U. Karymbaev, E. Kasatkin, N. Kashirina, C. Kaskiw, M. Kaspers, M. Kassim, A. Katebi, M. Kathan, D. Katnick, H. Katrip, A. Katyayan, J. Kaufman, S. Kaur, M. Kaur, S. Kaushik, T. Kavalec, J. Kavanagh, T. Kawadza, O. Kay, K. Kay, G. Kaya, J. Kaye, L. Kayyali, D. Ke, M. Kealey, R. Kean, E. Keane, J. Kearley, M. Kearley, R. Kearns, K. Keating, F. Kebede, M. Keck, R. Keddie, B. Keddie, A. Keebler, C. Keehn, T. Keenan, P. Keglowitsch, P. Kehler, C. Keil, P. Keiley, G. Keith, J. Kelenc, F. Keller, C. Kelley, C. Kellogg, E. Kellough, J. Kelloway, R. Kelloway, M. Kelloway, C. Kellsey, J. Kelly, P. Kelly, C. Kelly, M. Kelly, S. Kelsey, T. Kemmer, G. Kemp, L. Kempe, S. Kempner, J. Kempton, S. Kendall, R. Kendall, C. Kendell, D. Kendell, R. Kendell, M. Kendrick, R. Kennedy, B. Kennedy, J. Kennedy, K. Kennedy, W. Kennedy, M. Kennedy, S. Kennedy, G. Kennedy, R. Kenny, J. Kenny, L. Kenstavicius, D. Kent, S. Kent, M. Kent, V. Kenyon, D. Kenyon, K. Keough, S. Kermanshachi, S. Kernachan, C. Kerpan, S. Kerr, D. Kerr, J. Kerr, S. Kers, D. Ketchum, D. Kett, B. Kevol, M. Khalil, T. Khambalkar, A. Khan, G. Khan, M. Khan, F. Khan, S. Khan, R. Khatri, N. Khatri, J. Kho, F. Khodayari, S. Khong, S. Kiasosua, I. Kidd, R. Kidd, D. Kidger, B. Kidmose, B. Kiedyk, C. Kiehn, K. Kieley, L. Kiez, C. Kilback, D. Kilbreath, M. Kilcollins, C. Killick, O. Kilo, R. Kim, H. Kim, B. Kim, C. Kimler, D. Kimmie, M. Kinden, M. King, J. King, C. King, R. King, N. King, W. King, D. King, T. King, G. King, I. King, B. King, R. Kingcott, T. Kingsbury, S. Kinnear, C. Kinniburgh, P. Kip, B. Kirby-Graham, T. Kirchner, M. Kireev, T. Kirilo, R. Kirk, D. Kirkham, L. Kirkpatrick, W. Kirkpatrick, M. Kirkwood, B. Kisilewich, A. Kiss, B. Kiss, B. Kissel, M. Kissoon, F. Kitivi, C. Kiyawasew, B. Kiyawasew, G. Kjelshus, T. Kjemhus, J. Klaffl, J. Klapstein, K. Klassen, S. Klassen, J. Klassen, A. Klassen, R. Klassen, C. Klatt, D. Klause, R. Klautt, A. Klein, B. Klenk, R. Klimek, M. Klimkiewicz, E. Klitiris, J. Klotz, G. Kluthe, C. Knapper, R. Knee, S. Knelsen, W. Knelson, R. Kneteman, M. Kniebel, R. Knight, G. Knight, J. Knight-Ehiwe, J. Knipe, L. Knoblauch, D. Knoblich, B. Knopf, D. Knott, W. Knouse, G. Knowlton, T. Knox, K. Knox, J. Knox, P. Knull, M. Kobelka, D. Kobes, B. Kobzey, B. Koch, M. Koch, S. Kochan, E. Kodjo Gaba, R. Koenig, S. Koffi, K. Koffi, L. Koffi, K. Koger, C. Kohls, B. Kohrs, M. Kohut, J. Kohut, B. Koizumi, C. Kolberg, M. Kolenchuk, M. Kolesnikov, D. Kolundzic, B. Koma, M. Komant, S. Kompally, M. Kondor, B. Kondratowicz, B. Kone, L. Kone, V. Kone, Y. Kone, L. Kong, R. Konrad, M. Konschuh, E. Kontuk, B. Kootenay, P. Korba, S. Korchagin, M. Koren, P. Kornacki, B. Korolischuk, D. Korrey, J. Kosanovich, A. Kosasih, I. Koshcheev, D. Kosinski, B. Kosowan, V. Kostic, K. Kostrub, B. Kotchi, K. Kotkas, M. Kotty, D. Kotze, M. Koua, P. Kouadio, A. Kouakou, D. Kouame, A. Kouassi, H. Kouassi, G. Koumba Lendoye, A. Kourbaj, M. Koutou, M. Kovac, B. Kovacs, S. Kovacs, R. Kovalenko, R. Kovasin, M. Kowalchuk, J. Kowalewski, R. Kowalski, K. Kowbel, R. Kowbel, M. Kozak, G. Kozakevich, E. Kozakevich, T. Kozina, A. Kozler, A. Kozlowski, A. Kozovski, D. Krajci, B. Kraljic, J. Kramers, K. Kramps, R. Kranitz, T. Kratz, W. Kraus, T. Krause, G. Krause, R. Krauss, R. Kravitz, B. Krawchuk, C. Krawchuk, D. Krawec, J. Krawetz, M. Krawetz, J. Kreft, T. Kreics, M. Kreiser, B. Krell, V. Kremenskaia, J. Krenbrink, B. Kress, K. Krewulak, A. Krishnamoorthy, R. Krishnamurthy, H. Krislock, D. Krismer, B. Kristianson, N. Krochmal, R. Kroeker, K. Krogh, P. Krol, U. Krstic, R. Krueger, K. Kruger, G. Kruger, G. Kruk, N. Krupka, T. Krushel, C. Kubik, C. Kucinar, G. Kucy, J. Kuhberg, M. Kulkarni, W. Kullman, C. Kully, P. Kumar, S. Kumar, B. Kumar, R. Kumar, C. Kung, D. Kunitz, J. Kunka, J. Kuntz, P. Kuppers, S. Kurczaba, D. Kurek, M. Kureshi, M. Kurowski, K. Kurschenska, K. Kursteiner, D. Kurtz, R. Kurtz, F. Kurucz, G. Kushe, D. Kusmiadji, B. Kutash, K. Kuzevanova, F. Kuzmic, C. Kwan, K. Kwan, R. Kwiatkowski, S. Kwiatkowski, V. Kwiatkowski, A. Kwon, J. Kwong, T. Ky, J. Kyes, K. Kyffin, D. Kyle, R. Kynock, J. Kynock, T. La Grange, D. Labby, J. LaBossiere, R. Laboucan, J. Laboucan, A. Laboucan, D. Labrecque, T. Lacey, N. Lachance, A. LaChance, S. Lachance, J. Lacharite, R. Lacombe, K. Lacombe, P. Lacoste-Bouchet, S. Lacroix, D. Lacroix, M. Lacroix, L. Lacuna, A. Laderoute, K. Lafferty, S. Lafond, D. Lafontaine, R. Laforge, L. Lafreniere, D. Lafreniere, G. Lagace, M. Lagimodiere, B. Lagler, S. Lagos, A. Laguduva, D. Laha, M. Laha, B. Lahoda, D. Lahoda, J. Lahoda, S. Lai, C. Lai, R. Lai, E. Laidlaw, A. Laing, R. Laing, S. Laird, A. Laite, M. Lake, J. Lakes, P. Lalani, J. Laliberte, K. Lalonde, P. Lalonde, C. Lam, S. Lam, N. Lam, R. Lam, D. Lam, E. Lam, K. Lamb, T. Lamb, Z. Lamba, K. Lambert, D. Lambert, J. Lambert, S. Lambert, E. Lambert, R. Lameman, D. Lameman, T. Laminski, R. Lamontagne, J. Lamontagne, T. Lamoureux, W. Lamoureux, J. Lamoureux, W. Lamptey, L. Landry, S. Landry, J. Landry, M. Landry, Y. Landry, E. Landry, G. Landry, X. Landry-Pellerin, W. Landsburg, M. Lane, B. Lane, W. Lane, S. Lane, R. Lanfranchi, J. Langdon, K. Langdon, N. Lange, L. Lange, G. Lange, S. Lange, O. Lange, W. Langford, S. Langford, T. Langill, J. Langman, C. Langpap, B. Lanh, R. Laniec, N. Lanktree, C. Lanthier, L. Lanza, S. Lanza, C. Lapp, C. Lappin, M. Larade, G. Laramee, G. Lardner, J. Larkin, J. Larochelle, J. Larocque, A. Larocque, E. LaRose, G. Larrivee, R. Larsen, A. Larsgard, J. Larson, P. Larson, L. Larson, G. Larson, B. Larsson, A. Laser, J. LaSha Pool, M. Laslo, C. Lassey, W. Latchuk, A. Latif, Z. Latif, R. Latimer, C. Latimer, M. LaTorre, P. Latus, C. Lau, J. Lau, S. Lau, L. Laube, B. Laughlin, P. Laughman, P. Laurie, K. Laurin, M. Lausen, N. Laustsen, S. Laut, R. Lauze, J. Lauzon, M. Lavallee, D. Laventure, K. Laverty, P. Lavery, V. Laviano, B. Lavigne, J. Lavigne, C. Lavoie, Y. Law, I. Law, D. Law, C. Lawford, P. Lawless, S. Lawlor, S. Lawrence, E. Lawrence, L. Lawrence, R. Lawrence, D. Lawrence, B. Lawrence, Y. Lawrence, W. Lawrence, R. Lawrie, G. Lawson, J. Laya, C. Layes, T. Layland, P. Layland, K. Layland, S. Layton, K. Layug, G. Lazaruk, T. Lazowski, L. Le, N. Le, M. Le, T. Le, R. Le Manne, B. Leach, T. Leach, R. Leahy, A. Leam, L. Leamon, C. Lea-



mon, K. Leamon, D. Leask, A. Leather, M. Lebas, T. Leblanc, J. Leblanc, R. Leblanc, E. LeBlanc, W. LeBlanc, C. LeBlanc, P. LeBlond, S. LeBrun, C. Lebrun, S. Lebsack, S. Leclair, G. Leclerc, M. L'Ecuyer, G. Ledger, J. Ledoux, C. Ledrew, A. Lee, M. Lee, J. Lee, L. Lee, T. Lee, S. Lee, R. Lee, K. Lee, D. Lee, P. Lee, B. Leeman, J. Leeman, G. Lefebure, S. Lefebvre, D. Lefebvre, M. LeForte, K. Legault, D. Legault, L. Legault, P. Legere, J. Legere, M. Legge, M. LeGrow, K. Lehal, B. Lehbauer, M. Lehouillier, S. Lei, P. Leibel, T. Leibel, S. Leithoff, J. Leman, R. Lemoine, Z. LeMoine, T. Lemon, R. Lenes, P. Leniuk, P. Lennon, C. Lenz, S. Lenz, T. Leon, C. Leong, H. Leong, G. Leong, K. Lepage, T. LePage, S. Lepine, S. Lepp, L. Leppaie, P. Lepper, Y. Lerner, C. Leroux, E. Leroy, C. Leschinski, T. Lesko, G. Leslie, R. Leslie, S. Lester, B. Lesyk, C. Lesyk, K. Letby, M. Lethaby, T. Letkeman, F. Letkeman, P. Letkeman, M. Letourneau, A. Letourneau, H. Lett, A. Leung, J. Leung, Y. Leung, K. Leung, P. Leung, M. Leung, D. Leung, R. Leung, J. Levac, J. Levack, M. Levesque, J. Levesque, R. Levesque, S. Lewchuk, D. Lewis, J. Lewis, E. Lewis, P. Lewis, K. Lewis, C. Lewis, T. Lewis, W. Lewis, R. Lewis, W. Leyland, N. L'Heureux, J. L'Hirondelle, Q. Li, Y. Li, B. Li, J. Li, W. Li, H. Li, S. Li, B. Liang, N. Liang, S. Liao, C. Liba, M. Liber, N. Liegman, S. Lien, H. Lien, J. Lieverse, C. Lieverse, D. Lightburn, A. Likhar, D. Lilburn, M. Lim, H. Lim, Q. Lin, H. Lin, F. Lin, J. Lin, K. Linaker, B. Lind, S. Lindballe, K. Linder, T. Lindley, G. Lindner, E. Lindsay, D. Lindskog, D. Linfoot, A. Linggon, D. Link, P. Linklater, N. Linnell, J. Linton, M. Liou-McKinstry, R. Liske, S. Little, G. Little, C. Little, J. Little, J. Littlechilds, C. Litwin, J. Liu, H. Liu, W. Liu, Y. Liu, M. Liu, T. Liu, X. Liu, L. Liu, J. Liu Prest, J. Lively, R. Livingston, J. Livingston, K. Livingston, S. Livingstone, C. Lizee, J. Llanos, M. Lloyd, P. Lloyd, R. Lloyd, W. Lo, Y. Lo, A. Lobban, A. Lobbes, G. Lobdell, J. Lochansky, T. Locke, R. Locke, F. Locke, R. Lockhart, A. Lockhart, N. Lockhart, C. Loder, J. Lodoen, S. Loewen, K. Loewen, C. Lofstrom, M. Logan, C. Logan, D. Loggie, R. Logozar, S. Lojczyc, J. Lok, R. Loke, J. Lomada, D. Londo, Y. Long, D. Long, C. Long, S. Longman, S. Longson, C. Longston, I. Lonsbury, K. Loo, K. Lopez, J. Lopez Sanchez, D. Lord, N. Lord, J. Loree, C. Lorenson, J. Lorette, M. Lorincz, B. Lorinczy, M. Loring, K. Lorteau, M. Loshny, M. Lotfi, J. Lotito, T. Lougheed, A. Loughran, L. Louie, S. Lourido, W. Loutit, J. Louw, M. Love, C. Love, J. Loveless, D. Loveless, W. Loveless, I. Lovera-Figueroa, M. Lovestrom, E. Lovmo, N. Low, C. Lowe, D. Lowe, J. Lowen, K. Loyer, L. Loyola, C. Lozinski-Kumpula, M. Lu, W. Lu, J. Lu, A. Lu, I. Lucas, G. Lucas, J. Lucas, L. Luciow, T. Lucksinger, E. Ludwig, S. Lui, L. Luiken, M. Luimes, K. Luk, C. Luk, A. Lukacs, K. Lukan, L. Lukey, H. Lund, W. Lundell, J. Lundquist, V. Lundrigan, K. Lundrigan, E. Lunn, R. Lunn, J. Lunt, C. Lunzmann, X. Luo, M. Lupul, J. Luscombe, J. Lush, D. Lush, B. Lush, R. Lusk, A. Lussier, K. Lussier, C. Lutsch, D. Lutwick, J. Lutyck, K. Lutz, A. Ly, G. Lyall, K. Lyall, T. Lychuk, G. Lykidis, L. Lynch, K. Lynch, D. Lynch, R. Lynett, M. Lynn, W. Lyon, N. Lyons, R. Lyric, D. Lysak, V. Ma, H. Ma, N. Maawia, M. MacBeth, L. MacCallum, K. MacComish, M. MacConnell, L. Macdaid, C. Macdonald, J. MacDonald, R. Macdonald, P. MacDonald, A. MacDonald, L. MacDonald, M. Macdonald, T. Macdonald, D. Macdonald, W. MacDonald, F. MacDonald, S. MacDougall, A. MacDougall, M. MacDougall, J. MacDougall, T. Macdougall-Sinclair, L. MacEachern, A. MacEachern, T. MacEachern, M. MacEachern, J. MacEachern, C. MacEachern, Y. Macedo, M. Macfarlane, C. MacFarlane, K. MacGillis, A. Macgillivray, D. Macgowan, G. MacGregor, D. MacGregor, K. Machado Rodriguez, S. MacHale, D. Machuk, R. Maciborski, J. Maciejewski, T. Macijuk, S. MacInnis, A. MacInnis, L. MacIntosh, T. Macintyre, J. MacIntyre, R. MacIntyre, A. Mack, S. Mack, L. Mack, C. Mackay, L. Mackay, G. MacKay, S. MacKay, B. MacKay, K. Mackay, R. Mackelvie, D. Mackenzie, A. MacKenzie, T. Mackenzie, V. MacKenzie, S. MacKenzie, K. MacKenzie, M. MacKenzie, T. Mackey, P. Mackey, S. Mackey, B. MacKey, M. Mackie, K. MacKinnon, J. MacKinnon, B. MacKinnon, R. MacKinnon, P. MacKinnon, T. MacKinnon, A. MacKinnon, P. Mackintosh, T. MacLaren, B. Maclean, K. MacLean, M. MacLean, C. MacLean, E. MacLean, R. MacLean, D. Maclellan, A. MacLellan, J. MacLellan, M. MacLellan, G. MacLellan, J. MacLennan, A. MacLeod, J. Macleod, T. MacLeod, L. MacLeod, I. MacLeod, M. MacLeod, W. MacLeod, C. MacLeod, H. MacMillan, N. MacMillan, B. MacNeil, A. Macneil, C. Macneil, J. Macneil, B. MacNeill, A. MacNiven, W. MacPherson, C. MacPherson, B. MacPhie, H. Macrae, M. MacRitchie, T. MacVicar, E. MacVicar, B. Macwilliams, C. Madadi, A. Madhukar, H. Madi, R. Madigan, C. Madill, H. Madlung, D. Madoche, G. Madore, M. Madro, S. Madsen, G. Madsen, M. Maennchen, L. Maga, D. Maganga, J. Magbanua, D. Magee, B. Mageza, S. Magill, P. Magnan, C. Magnan, M. Magnusson, D. Magnusson, J. Magpali, A. Magro, V. Magsila, D. Magson, R. Maguet, M. Mah, R. Mah, D. Mah, N. Mahar, K. Mahboobi, Z. Mahe, T. Mailandt, M. Mailhot, E. Maillet, J. Maillet, D. Maillet, P. Mailloux, M. Mailloux, R. Mailman, J. Mainville, B. Maisey, D. Maisey, O. Maita, S. Majdnia, J. Majeau, A. Majidi, P. Major, J. Makahnouk, M. Makhoul, D. Maki, M. Makin, D. Makin, L. Makowichuk, G. Makumbe, E. Malabad, D. Malabad, A. Malabad, J. Malazdrewicz, S. Malcolm, H. Maldonado, M. Malech, P. Malhame, A. Malimban, T. Malkova, J. Mallard, K. Mallard, S. Mallay, G. Mallette, T. Malley, G. Malo, T. Maloney, D. Malowski, A. Maltseva, G. Malvar, M. Malyk, O. Malyshev, S. Mamedov, F. Manangu, D. Manarang, G. Mancas, E. Mancelita, M. Manderscheid, D. Mandley, D. Manengyao, J. Manful, M. Manhera, D. Manitopyes, E. Mankowski, D. Mann, K. Mann, R. Mann, S. Mann, G. Mann, J. Manning, K. Manolov, J. Mansfield, D. Manshanden, R. Mantei, V. Mantey, A. Manthorne, E. Mantilla, G. Manuel, J. Manuel, G. Manuel-Goodyear, L. Manzano Weffer, H. Maralli, N. Maralli, M. Maratovic, D. Marazzo, G. Marceau, A. Marcel, N. Marchand, L. Marchand, F. Marchesan, M. Marchi, R. Marcichiw, A. Marcinkoski, T. Marcotte, L. Marcucci, N. Marcy, J. Margetson, W. Margison, H. Maric, V. Maries, E. Marilao, S. Marin, P. Marinzi, S. Marion, D. Mark, S. Markle, S. Markosyan, K. Markstrom, M. Markussen, P. Marolt, U. Maroney, B. Marple, A. Marquardt, T. Marquis, D. Marr, K. Marriner, R. Marrington, M. Marsh, A. Marsh, B. Marsh, N. Marsh, C. Marsh, P. Marsh, C. Marshall, G. Marshall, S. Marshall, K. Marshall, D. Marshall, J. Marston, A. Martakoush, P. Martell, S. Martens, D. Martens, A. Marter, M. Martin, D. Martin, J. Martin, S. Martin, B. Martin, K. Martin, C. Martin, T. Martin, R. Martin, D. Martinat, S. Martinella, M. Martinez, Z. Martinez, D. Martinez Gomez, O. Martis, D. Martyn, R. Martyn, M. Martynuik, M. Martyshuk, A. Martyshuk, J. Maruniak, K. Mashayekh, R. Maskoni, C. Mason, B. Mason, J. Mason, D. Massey, K. Massick, A. Massicotte, P. Massicotte, M. Mata, A. Matatko, T. Matatko, A. Matchem, J. Matecki, H. Mateen, D. Mathers, D. Matheson, E. Matheson, L. Matheson, A. Mathew, L. Mathew, K. Mathews, D. Mathieson, F. Mathieson, C. Mathiot, C. Matkin, J. Matkowski, B. Matsalla, T. Matsushita, N. Matsushita, C. Matthews, A. Matthews, N. Matthews, E. Matthews, B. Matthews, J. Matthiessen, R. Matychuk, S. Maurice, P. Maurice, A. Maurier, N. Mavani, D. Mavridis, D. Mavuwa, A. Mawer, V. Maximo, C. Maxsom, R. Maxwell, J. Maxwell, K. May, R. May, C. Maye, F. Mayell, S. Mayer, J. Mayer, R. Mayers, W. Maynard, A. Maynard, K. Mayner, A. Mayo, B. Mayo, C. Mays, A. Mazur, C. Mazuryk, D. McAlister, C. Mcallister, D. McAllister, J. McAllister, M. McAlpine, K. Mcarthur, D. McArthur, E. McAvoy, N. McBain, K. McBride, R. McBrien, T. McCabe, D. McCabe, G. McCabe, S. McCaffrey, J. McCaffrey, R. McCallum, S. McCann, D. McCarry, J. McCarthy, M. McCarthy, J. McCarty, D. McCarvill, K. McClary, D. McClelland, I. McClelland, J. Mcclyment, B. McConachie, C. McConnell, M. McCormack, C. Mccoy, S. McCracken, B. McCrady, K. McCrae, G. McCrea, C. McCrea, J. McCrea, J. Mccready, S. McCreery, G. Mccubbing, B. McCullagh, R. McCullough, B. McCullough, C. McCullough, D. McCullough, E. McCullough, A. McDaniel, J. McDonald, K. McDonald, T. McDonald, C. McDonald, D. McDonald, C. McDonell, L. McDonnell, M. McDougall, K. McDougall, S. McDougall, J. McDowell, R. McEachnie, M. McElroy, N. McElroy, P. McElwain, S. McEvoy, T. McEwen, J. McEwen, W. McEwen, J. Mcfarland, C. McFarlane, M. McFarlane, A. McFaul, B. McFaul, L. McFeeters, F. McGaw, L. McGean, C. Mcgee, L. McGee, D. McGee, P. McGinnis, G. Mcgonigal, C. McGovern, G. McGowan, L. McGrath, K. Mcgrath, D. Mcgrath, A. McGrath, M. McGrath, C. McGrath, T. McGrath, T. McGregor, P. McGregor, S. McGregor, J. McGuckin, S. McHardy, L. McHugh, D. McIlvaney, W. McIntosh, M. Mcintosh, D. McIntosh, A. McIntosh, G. McIntosh, R. McIntyre, P. McIntyre, C. McIntyre, C. McIver, T. McKague, R. McKay, N. McKay, B. Mckay, K. McKay, T. McKay, S. McKay, L. McKay, J. McKay, C. McKay, N. McKeachnie, T. McKee, W. McKellar, N. McKendry, K. McKendry, T. McKenna, P. McKenna, M. McKenna, R. McKenzie, K. McKenzie, B. McKenzie, M. McKenzie, D. Mckersie, K. McKetiak, H. McKiel, C. McKim, S. McKinney, J. Mckinnon, S. McKinnon, W. McKinnon, K. Mckinnon, R. McLachlen, M. McLane, M. McLaren, D. McLaren, C. McLaren, H. McLarty, T. Mclaughlan, S. McLaughlan, R. McLaughlin, M. McLaughlin, K. McLaughlin, B. Mclean, H. McLean, M. McLean, N. McLean, R. McLean, W. Mclean, K. McLellan, C. McLellan, T. McLellan, A. McLellan, C. McLenaghan, M. McLenehan, G. McLennan, I. McLeod, S. McLeod, D. McLeod, T. McLeod, C. McLeod, M. McLeod, P. Mcloughlin, L. McMahon, E. McMahon, G. McMahon, K. McMann, N. McManus, R. McMaster, J. McMaster, S. McMichael, J. McMillan, R. McNabb, R. McNair, D. McNamara, R. McNaughton, J. McNaull, M. McNay, M. McNeil, R. McNeil, D. McNeil, P. McNeil, K. McNeil, S. McNeill, T. McNelly, R. McPhail, L. McPhee, R. McPhee, K. McPherson, J. McPherson, C. McQuaker, E. McQueen, J. McQueen, A. McQueen, C. McQuiggin, L. McQuiston, R. McRae, K. McRae, A. McSharry, J. McTamney, T. McTavish, B. McTavish, C. McWhan, V. McWhan, C. McWhinnie, M. Meade, D. Meador, B. Meadus, P. Meadus, S. Meagher, M. Meakes, M. Meckelborg, M. Medhurst, N. Medina, I. Medina, D. Medlicott Lymburner, B. Medway, J. Meeks, K. Meh, M. Mehaney, F. Mehdiyev, V. Mehta, N. Mehta, C. Mei, D. Meier, C. Mejia, J. Mejia, J. Melanson, B. Melanson, D. Melanson, R. Melanson, T. Melindy, H. Mellafont, L. Mello, G. Mellom, M. Melnyk, D. Melnyk, R. Melnyk, K. Melnyk, A. Melo, B. Melton, J. Melville, A. Menard, L. Mendenhall, P. Mendes, M. Mendonca, A. Mendoza, N. Meneses, D. Menjivar, B. Mennie, P. Menzel, M. Mer, G. Merali, C. Mercer, J. Mercer, R. Mercer, J. Mercier, W. Mercredi, G. Merkel, C. Merkel, D. Merkley, A. Merle, S. Merralls, M. Merrill, M. Merriman, R. Merritt, N. Merritt, C. Merritt, U. Meservy, S. Metcalfe, T. Methuen, C. Metz, K. Metzler, S. Meunier, R. Mewis, C. Mews, R. Mews, D. Mews, A. Mews, I. Meynin, L. Michalishen, C. Michalko, J. Michaud, B. Michaud, T. Michel, K. Michener, L. Michon, K. Mickel, N. Mickelson, J. Miclat, D. Midgley, K. Mielty, J. Mihai, J. Mihailoff, M. Miiller, T. Mijic, A. Mikhailov, S. Mikloukhine, J. Miko, G. Milan Garcia, J. Milce, J. Mildenberger, R. Miles, R. Millar, B. Miller, S. Miller, R. Miller, W. Miller, K. Miller, T. Miller, D. Miller, G. Miller, L. Miller, L. Milligan, R. Mills, G. Mills, J. Mills, T. Mills, S. Mills, D. Mills, C. Mills, J. Millwater, J. Milne, A. Milne, D. Milward, F. Mingle, A. Minhas, M. Minick, W. Minni, W. Minns, D. Mino, J. Minor, A.

Minty, T. Mir, A. Mir, S. Mir, W. Mirabal, B. Mirza, W. Mirza, A. Mirza, M. Mirzadeh, J. Mistecki, D. Mistry, T. Mitchell, M. Mitchell, C. Mitchell, G. Mitchell, J. Mitchell, R. Mitchell, W. Mitchell, Y. Mitchell, M. Mitton, Y. Miville, P. Mo, V. Modak, B. Moelbert, J. Moffat, I. Moffat, R. Mogensen, A. Mognin, S. Mohamed, A. Mohamed, S. Mohammad, B. Mohammed, G. Mohammed, A. Mohideen, J. Mohl, D. Moisan, M. Moisson, M. Molde, N. Molder, N. Molina, R. Mollison, J. Molnar, T. Molyneux, T. Mombourquette, R. Monahan, R. Money, P. Monfette, C. Montague, F. Montefresco-Gentile, R. Monteith, V. Montenegro, N. Montes, J. Montgomery, M. Montinola, S. Moojelsky, P. Moon, K. Moon, C. Mooney, B. Moore, D. Moore, J. Moores, L. Mora, A. Moradi Afrapoli, A. Morado, A. Morelli, K. Morency, L. Moreno, J. Moretto, C. Morgan, T. Morgan, J. Morgan, M. Morganton, M. Moriarty, A. Morin, J. Morin, M. Morin, P. Morin, R. Morin, J. Morley, R. Morley, K. Morphy, D. Morris, K. Morris, B. Morris, J. Morris, M. Morris, S. Morris, I. Morris, J. Morriseau, C. Morrison, J. Morrison, T. Morrison, R. Morrison, C. Morriss, W. Morrow, S. Morse, D. Morsette, A. Mortlock, K. Morton, D. Morton, L. Morton, M. Morvik, D. Mose, D. Moser, K. Moser, J. Moshenko, T. Moskol, P. Mossey, C. Mostowich, J. Mostyn, S. Mothersele, L. Motowylo, S. Motta Cabrera, B. Mottle, S. Moul, L. Mounkes, I. Mountain, P. Mouori Mbani, S. Mousazadeh, O. Moussa, M. Mousseau, D. Mouton, C. Moyls, D. Mrakava, M. Mubarak, T. Mudzviti, Z. Mueller, T. Mueller, T. Muessle, A. Mugford, R. Mugford, M. Mughal, S. Muhammad, K. Muir, D. Muise, L. Muise, K. Mullaly, G. Mullen, S. Muller, B. Mulligan, R. Mullin, C. Mullin, A. Mulumba, N. Mulvena, S. Mundt, K. Munn, I. Munro, L. Munro, R. Munro, A. Munro, J. Munro, C. Murdoch, I. Murdoch, J. Murdoch, G. Murley, L. Murley, P. Murphy, T. Murphy, A. Murphy, B. Murphy, C. Murphy, R. Murphy, J. Murphy, K. Murphy, D. Murphy, J. Murrant, B. Murray, L. Murray, S. Murray, G. Murray, C. Murray, S. Murrin, E. Murrin, M. Musaid, A. Mushava, I. Musiwarwo, W. Muss, D. Musselman, T. Musselman, N. Musterer, Z. Musuna, A. Muthuswamy, R. Mutschler, T. Mutter, J. Mweshi, E. Myers, D. Myers, S. Myers, L. Myhre, D. Myshak, M. Myszczyszyn, G. Nabi, J. Nachtigal, B. Nadeau, S. Nadeau, M. Naderikia, S. Nagarajan, S. Nagare, A. Nagra, J. Nagy, J. Nagy-Kolodychuk, L. Nahas, J. Naidu, S. Nair, R. Nair, N. Nair, J. Nair, S. Najeeb, L. Najoan, B. Nalder, N. Namoca, E. Namur, J. Napier, R. Napier, C. Naqvi, S. Naqvi, P. Narayan, K. Narayanan, A. Narcise, S. Naser, J. Nash, D. Nater, M. Nathwani-Crowe, A. Naughton, D. Naugler, P. Nava, L. Navarrette, D. Navas, R. Navas, V. Navratil, M. Nawab, S. Nayak, C. Nazarko, N. N'Doye, D. Neal, N. Neale, M. Neate, A. Neddjar, D. Neergaard, J. Neff, S. Negi, Y. Neguse, D. Neigum, S. Neilson, A. Neilson, D. Nein, K. Nelligan, D. Nelson, K. Nelson, R. Nelson, C. Nelson, V. Nelson, J. Nelson, M. Nelson, B. Nelson, A. Nelson, A. Nemirsky, M. Nergaard, N. Nernberg, G. Nesbitt, B. Nessman, K. Netter, K. Nettesheim, G. Netzel, O. Neufeld, C. Neufeld, F. Neumaier, D. Neumann, D. Nevil, W. Nevills, D. Newbury, A. Newell, B. Newell, R. Newitt, L. Newman, P. Newman, J. Newman, R. Newman, M. Newman, A. Newman, K. Newton, R. Newton, A. Newton, J. Ng, D. Ng, R. Ng, S. Ng, K. Ng, V. Nganzo, P. N'Gbesso, H. Ngo, N. Ngo-Schneider, H. Ngowe, C. N'Guessan, T. Nguyen, M. Nguyen, C. Nguyen, H. Ni, D. Niamke, F. Nichol, J. Nicholl, J. Nichols, D. Nichols, S. Nicholson, J. Nicholson, A. Nicholson, A. Nickel, D. Nickerson, K. Nickerson, J. Nicolai, J. Nicolajsen, E. Nicolas, T. Nicolas, J. Nicoll, J. Nie, M. Nielsen, K. Nielsen, T. Nielsen, O. Nieto, M. Nieves, P. Nihon, W. Nikiforuk, C. Nikipelo, R. Nimco, T. Ninovska, R. Nippard, M. Nippard, D. Nissen, J. Nistico, O. Niven, K. Nixon, P. Niziolek, A. N'Kesse, M. Nobles, C. Noel, B. Noel, D. Noel, A. Noftall, J. Noga, G. Nogue, R. Nolan, S. Nolan, B. Nolan, P. Nolan, G. Nolin, B. Nolin, R. Noot, W. Nordin, J. Norgaard, A. Nori, A. Noriel, V. Norkin, T. Norman, J. Norman, D. Norman, R. Norman, P. Norman, B. Norman, Y. Normand, T. Normand, D. Normore, S. Normore, C. Normore, B. Norquay, L. Norrad, N. Northcott, R. Norton, S. Norton, K. Norton, B. Noseworthy, A. Noskey, K. Notenbomer, F. Nothnagel, E. Notter, J. Novak, R. Novales, O. Novikova, D. Nowicki, D. Noyes, R. Nunweiler, D. Nwagbogwu, R. Nycholat, E. Nyenhuis, A. Nylen, C. Nyman, W. Oak, N. Oake, R. Oakes, W. Oakes, K. Oaks, A. Obad, D. Ober, J. Oberg, N. Obi, F. Obiri, Y. Oble-Karike, P. Oblozinsky, K. O'Brien, D. O'Brien, H. O'Brien, P. O'Brien, B. O'Brien, J. Obrigewitsch, J. Obuck, M. Ochran, J. O'Connell, M. O'Connell, G. O'Connor, D. Oczkowski, P. O'Donnell, T. Oele, J. Oestreicher, S. O'Farrell, H. Offet, I. Offor, E. Ofuya, L. O'Gallagher, J. Oganwu, O. Ogbodo, A. Ogden, M. Ogden, M. Ogg, A. Ogilvie, R. Ogilvie, D. Ogilvie, J. O'Grady, D. Ogren, B. Ogurian, J. Oh, T. Oh, T. Oickle, R. Okada, E. O'Keefe, C. O'Keefe, L. Okemow, A. Okeynan, R. Oksanen, K. Okuszko, E. Okyere, F. Oladebo, P. Olaniyan, S. Olar, A. Olaski, B. Olaski, C. Oldfield, S. O'Leary, S. Olechow, B. Olenik, D. Olesen, B. Olheiser, T. Olinek, N. Oliver, D. Oliver, A. Oliverio, C. Olivier, T. Ollenberg, D. Ollenberger, S. Ollerhead, J. Ollikka, V. Olofernes, G. Oloumi, R. Olsen, S. Olsen, J. Olsen, M. Olsen, K. Olsen, J. Olson, W. Olson, C. Olson, V. Olson, D. Olson, S. Olson, O. Oluwole, M. Omosun, P. Onciul, D. O'Neil, T. O'Neill, D. Ong, K. Onuoha, P. Onyszko, E. Opian, C. Opper, C. Ordonez, R. O'Regan, N. O'Reilly, M. O'Reilly, A. O'Reilly, D. Orlecki, M. Orosz, J. O'Rourke, L. Orpilla Jr, N. Orr, A. Orr, S. Orser, P. Ortega, M. Ortega, K. Orth, R. Osachoff, J. Osborne, C. Osborne, D. O'Shea, J. Oshman, D. Osinchuk, M. Osman, K. Osmond, T. Osmond, L. Osorio, H. Osorio Lobo, A. Ospino, B. Ostenberg, J. O'Sullivan, K. Osuoji, D. Oswald, J. Otis, J. O'Toole, G. Ott, K. Otte, C. Ottenbreit, W. Otteson, M. Otteson, L. Otteson, J. Otto, T. Otway, T. Ouart, L. Ouch, D. Ouellette, J. Ouellette, S. Ouellette, Z. Overbye, E. Overbye, M. Overwater, A. Owsianicki, A. Oxford, P. Oza, P. Ozar, A. Paananen, L. Paananen, J. Paarsmarkt, M. Pachan, M. Pacheco, F. Pacheco, D. Pacholok, S. Pacholok, T. Packard, J. Paddington, R. Padilla, T. Padron, M. Pady, S. Page, Q. Pagnucco, T. Pagura, G. Pahl, D. Pahljina, S. Paiement, K. Paige, R. Paine, K. Painter, J. Pak, V. Pak, B. Pallan, K. Palmer, L. Palmer, D. Palmer, R. Palmer, J. Palmer, B. Palmer, E. Palmer, O. Palomino, A. Palou, G. Palsen, J. Palsis, P. Palumbo, I. Panas, J. Panas, B. Panchal, V. Pandey, D. Pandher, S. Pandya, J. Pandya, C. Panokarren, L. Pantazi, F. Pantilag, S. Panuganty, Y. Panya, A. Papadoulis, R. Papalia, M. Papcun, J. Papp, V. Papuga, P. Paquette, R. Paquette, L. Paquin, J. Paradis, D. Paradis, E. Paradis, T. Paradis, M. Paranjape, B. Parathundathil, G. Parchewsky, P. Parchure, M. Pardy, E. Parece, L. Paredes, B. Parent, J. Parenteau, B. Parenteau, C. Parenteau, L. Parillo, R. Parillo, D. Parker, J. Parker, B. Parker, D. Parlee, M. Parmar, C. Paron, B. Parsons, M. Parsons, T. Parsons, C. Parsons, G. Parsons, S. Parsons, W. Parsons, A. Partsch, J. Pashko, M. Pasichnuk, W. Pasko, J. Pasos, N. Pasowisty, E. Pastor, P. Patel, K. Patel, S. Patel, J. Patel, A. Patel, D. Patel, M. Patel, T. Patel, V. Patel, N. Patel, B. Patel, R. Patel, H. Patel, N. Pateliya, C. Pater, L. Paterson, J. Paterson, A. Paterson, H. Paterson, T. Paterson, T. Patey, M. Patey, I. Patey, B. Patey, J. Patey, D. Patey, J. Patience, P. Patil, K. Patmore, C. Paton, G. Paton, W. Patrick, C. Patrie, E. Patten, C. Patterson, L. Patterson, B. Patterson, J. Patterson, W. Patterson, K. Patterson, Z. Patterson, C. Pattinson, J. Paul, T. Paul, G. Paul, K. Paul, C. Paul, M. Paulgaard, E. Paulin, J. Paulsen, B. Paulson, B. Paulssen, B. Pauwels, D. Pavelick, M. Pavlic, A. Pawlowich, M. Pawluk, C. Pay, C. Paylor, G. Payne, J. Payne, D. Payne, M. Payne, B. Payne, P. Payne, S. Payson, P. Pazienza, K. Peach, E. Peacock, L. Peacock, B. Peacock, P. Pearson, J. Pearson, D. Pearson, E. Pearson, T. Peats, T. Peciulis, M. Peck, E. Peddle, S. Pedersen, D. Pedersen, K. Pedersen, P. Pedersen, J. Pedersen, C. Pederson, L. Pederson, B. Pederson, B. Peebles, J. Peeke, M. Peeke, R. Peel, D. Peet, K. Peeters, C. Peifer, F. Pelayo, K. Pelayo, M. Pelkey, G. Pellegrino, D. Pelletier, T. Pelletier, N. Pelletier, M. Pelletier, E. Pelletier, I. Pelly, M. Pelypiw, D. Pemberton, L. Pena, Y. Peng, J. Penman, T. Pennell, C. Pennell, S. Pennemann, S. Penner, D. Penner, P. Penney, E. Penney, H. Penney, D. Penney, M. Penney, C. Penney, J. Penney, S. Penny, J. Penzo, I. Pepper, K. Pepper, D. Peramanu, S. Peramanu, R. Peraza, M. Perdue, C. Peregrym, S. Perehudoff, J. Perepelecta, F. Perez, L. Perez, J. Perez-Licera, R. Perkins, T. Perkins, M. Perkins, D. Perkins, S. Perkins, J. Pernitsch, J. Peroramas, H. Perozak, D. Perreault, N. Perron, S. Perry, C. Perry, B. Perry, O. Perry, V. Perry, G. Perry, R. Perry, J. Perry, D. Perry, T. Persaud, B. Persson, D. Perumal, B. Pesowski, P. Peter, R. Peters, G. Peters, A. Peters, D. Peters, J. Peters, K. Peters, E. Peters, E. Petersen, T. Peterson, S. Peterson, M. Peterson, E. Peterson, A. Peterson, B. Peterson, J. Peterson, C. Petkau, D. Petkau, B. Petkus, L. Petrillo, N. Petrola, R. Petrone, R. Pettigrew, B. Pettipas, S. Pettit, D. Petz, A. Pewekar, K. Peyman, J. Peyton, K. Pfannmuller, R. Pfriem, L. Pham, L. Phan, B. Philibert, G. Philip, J. Phillips, D. Phillips, B. Phillips, L. Phillips, T. Phillips, D. Philp, T. Philpott, B. Philpott, Z. Philpott-Belzil, G. Phinney, M. Phippen, L. Phoenix, L. Picard, W. Picard, E. Picard-Goulet, K. Picco, J. Picken, J. Pickering, K. Pickering, P. Pickersgill, A. Pickersgill, B. Piderman, D. Pierce, S. Piercey, J. Pieroway, S. Pierzchala, A. Pietrusik, R. Pighin, J. Pihowich, S. Pike, J. Pike, P. Pilecki, T. Pilgrim, L. Pilgrim, B. Pilgrim, S. Pilgrim, M. Pili, D. Pilisko, J. Piliszanski, R. Pillai, L. Pillaveethil, N. Pilote, J. Pilsner, G. Pimienta, C. Pinchak, M. Pineda, L. Pineda Perez, E. Pinituj-Flores, W. Pinksen, T. Pinksen, J. Pintaric, B. Pipa, J. Pipke, C. Pirnak, D. Pirvan, K. Pisio, M. Pitman, J. Pitoulis, M. Pitre, M. Pittman, A. Pittman, C. Pittman, I. Pittman, J. Pittman, D. Pittman, W. Pittman, S. Pittman, E. Pittman, S. Pituka, C. Plain, R. Plamondon, M. Plamondon, E. Plante, J. Plata, D. Plepelic, I. Plesa, J. Plessis, G. Plews, N. Plouffe, T. Plouffe, S. Plouffe, J. Plowman, E. Plumb, J. Plummer, I. Pocaterra, J. Pocock, S. Podhorodeski, A. Poetker, H. Poffenroth, D. Pohl, K. Poirier, D. Poirier, A. Poirier, S. Poirier, D. Poitras, J. Polacik, D. Pole, E. Poliquin, C. Pollard, R. Pollard, T. Pollard, T. Pollett, J. Pollock, M. Pollock, A. Pollock, J. Polsfut, M. Polujan, G. Pome Franco, S. Pon, M. Poncelet, D. Poncsak, B. Pond, D. Pond, B. Ponjevic, N. Ponkiya, H. Ponnurangan, T. Poole, K. Poon, A. Popa, G. Pope, T. Pope, J. Popko, C. Popko, J. Popoff, J. Popowich, M. Popowich, C. Portelance, J. Portelli, I. Porter, L. Porter, A. Porter, C. Porter, M. Posnikoff, P. Postlewaite, R. Postnikoff, N. Pothier, M. Potorti, C. Potorti, T. Potter, J. Potter, K. Potts, R. Potts, J. Poulin, R. Poulter, K. Pounall, I. Pouncey, C. Povse, T. Powell, C. Powell, J. Powell, D. Powell, R. Powell, P. Powell, B. Power, L. Power, P. Power, A. Power, C. Power, T. Power, M. Power, S. Power, J. Power, E. Power, K. Power, D. Pozniak, M. Prajapati, D. Prasad, G. Pratch, G. Prather, S. Pratt, K. Pratt, R. Pratt, L. Praud, W. Prawdzik, D. Prediger, M. Preece, J. Prefontaine, D. Preshyon, J. Preshyon, D. Presley, J. Preston, A. Preston, R. Preteau, M. Price, W. Price, A. Price, C. Price, J. Priest, D. Pringle, T. Prins, M. Pritchard, A. Pritchard, R. Pritchett, S. Pritchett, K. Proc, G. Prochner, K. Proctor, D. Procyshyn, M. Profiri, N. Proll, M. Pronk, J. Properzi, M. Prosper, D. Prostebby, D. Prostler, I. Proudfoot, D. Proulx, K. Prowse, T. Prudhomme, S. Prud'Homme, C. Prybylski, C. Przybylski, S. Pshyk, Y. Puerto, J. Puhl, M. Pumphrey, C. Pumphrey, A. Punko, K. Pupneja, S. Pupneja, B. Purcell, S. Purchase, J. Purdy, C. Purdy, T. Purves, D. Pushak, S. Pushak, R. Pyke, J. Pyke, W. Pyne, M. Pyne, F. Pynn, T. Pyo, J. Pyper, R. Qazi, W. Qian, M. Qian, L. Qing, J. Qu, C. Quach, L. Quan, A. Quan, G. Quan, A. Quarin, R. Quartermain, K. Quaschnick, J. Quiba, S. Quigley, R. Quigley, D. Quigley, C. Quinlan, J. Quinn, K. Quintilio, M. Quintin, G. Quinton, B. Quipp, S. Qureshi, J. Raban Mardelli, L. Rabbitt, J. Rabby, B. Rabusic, M. Raby, P. Racette, D. Rach, D. Rachkewich, D. Raciborski, W. Raczynski, L. Radesh, R. Radke, K. Radke, A. Radtke, M. Radu, J. Rae, R. Rae, D. Raedts, K. Raemdonck, K. Rafferty, I. Rafiyev, G. Raghavan Nair, J. Raher, M. Rahmani, A. Rahmani, M. Rahmanian, P. Rai, J. Rainnie, M. Raistrick, A. Raivio, M. Raj, K. Raj, J. Rajotte, P. Ralph, J. Ralph, S. Raman, J. Ramazani, D. Ramburrun, R. Ramirez, P. Ramirez, M. Ramirez, J. Ramirez, E. Ramirez Capitaine, C. Ramos, M. Ramsay, S. Ramsay, J. Ramsay, K. Ramsbottom, M. Rana, L. Rancourt, W. Randell, D. Randell, M. Randell, L. Randell, C. Randell, T. Randell, R. Rane, M. Rankin, J. Rankin, D. Ranola, J. Ransom, P. Rao, M. Raoufi, R. Raposo, S. Rasch, T. Rasheed, C. Rasko, K. Raskob-Smith, S. Rasmussen, R. Raso, H. Rassi, W. Ratcliffe, R. Rathburn, S. Ratkovic, M. Rattray, H. Ratzlaff, A. Rau, M. Rausch, P. Raval, L. Ravoy, B. Rawling, C. Rawson, A. Ray, B. Ray, D. Ray, S.

Ray, K. Rayment, D. Raymond, E. Rayner, J. Rayner, R. Rayner, M. Raza, K. Razniak, F. Re, K. Read, D. Read, B. Read, W. Reashore, R. Reaume, D. Reber, C. Reber, D. Rechenmacher, Y. Redda, G. Redding, B. Redlich, E. Redlon, J. Redmann, J. Reed, G. Reed, S. Reed, P. Regan, R. Reginato, C. Regnier, R. Regnier, P. Regular, K. Rehel, M. Rehman, H. Rehman, C. Reib, R. Reid, G. Reid, C. Reid, J. Reid, E. Reid, K. Reid, T. Reid, M. Reid, B. Reid, D. Reid, S. Reilly, H. Reilly, T. Reilly, D. Reimer, I. Reimer, M. Reinders, T. Reinders, D. Reinhold, J. Reiniger, T. Reiniger, M. Reinkens, R. Reis, E. Reis, G. Reiter, H. Reithaug, D. Rejman, D. Relkow, W. Remmer, C. Rempel, P. Rempel, T. Rempel, L. Rempel, L. Ren, S. Ren, R. Renaud, G. Renfrew, T. Renkema, L. Rennie, C. Rennie, A. Rennie, J. Rennie, M. Reno, J. Rentar, J. Repchuk, S. Resus, C. Revereza, M. Rew, E. Reyes, O. Reyes, P. Reynolds, A. Reynolds, T. Reynolds, J. Reynolds, S. Reynolds, D. Reznik, N. Rhemtulla, C. Rhode, A. Rhodes, I. Riach, G. Ricard, A. Ricardo, S. Ricci, R. Rice, J. Rice, K. Richard, M. Richard, J. Richard, C. Richard, D. Richards, B. Richards, C. Richards, G. Richards, K. Richardson, I. Richardson, T. Richardson, A. Richardson, P. Richer, C. Ricketson, A. Ricketts, M. Ricketts, W. Ricketts, C. Rico-Ospina, R. Riddell, J. Riddle, R. Rideout, J. Rideout, M. Rideout, T. Rider, C. Riegling, C. Ries, W. Riewe, M. Rigg, A. Riley, D. Riley, S. Riley, D. Rimmer, D. Rinas, G. Ringheim, S. Rioux, K. Rioux, R. Rioux, P. Riseley, S. Risling, S. Ristic, L. Ritchat, M. Ritchie, D. Ritchie, L. Ritchie, R. Ritchie, D. Ritter, K. Ritter, A. Riutta, S. Rivard, J. Rivera, E. Rivera, M. Rizwan, J. Robak, T. Robb, N. Robbins, R. Roberge, A. Robert, C. Roberts, T. Roberts, D. Roberts, M. Roberts, J. Roberts, M. Robertson, S. Robertson, P. Robertson, G. Robertson, K. Robertson-Baldwin, B. Robia, J. Robichaud, M. Robideau, H. Robillard, M. Robinson, N. Robinson, D. Robinson, J. Robinson, T. Robinson, G. Robinson, S. Robinson, A. Robinson, K. Robinson, B. Robinson, W. Robleto, C. Robson, S. Robson, A. Rocha, L. Roche, G. Rocheleau, J. Rochemont, R. Rock, S. Rodberg, T. Rodgers, R. Rodh, J. Rodriguez, G. Roesler, P. Roett, D. Rogal, K. Rogalsky, P. Rogatschnigg, G. Rogers, K. Rogers, C. Rogers, J. Rogers, S. Rogers, M. Rogers, M. Rogne, L. Rojas, S. Rolling, T. Rolseth, K. Rolseth, P. Roman, T. Romanchuk, L. Romanchuk, B. Romanovich, D. Romanyshyn, M. Rombough, A. Romero, J. Romero, G. Romero, S. Rommelaere, G. Ronald, A. Ronald, D. Rondeau, S. Roney, J. Roney, L. Rong, P. Ronnie, B. Ronspies, A. Rook, J. Rooney, M. Rooney, C. Root, A. Roozendaal, T. Rosciski, R. Rose, C. Rose, M. Rose, B. Rose, J. Rose, K. Rose, P. Rose, M. Rose-Atkins, R. Rosenthal, D. Rosgen, S. Roskey, M. Rosloot, T. Rosner, E. Ross, W. Ross, J. Ross, R. Ross, D. Ross, A. Ross, M. Ross, I. Ross, R. Rossburger, G. Rosser, G. Rosso, J. Rostad, R. Rosychuk, B. Rosychuk, B. Roszell, M. Roth, K. Roth, R. Roth, T. Roth, C. Roth, B. Rott, T. Rotzien, J. Rotzoll, S. Rouf, D. Rough, D. Roughton, N. Rouidi, J. Rouleau, G. Rousselle, D. Routhier, A. Routhier, R. Routhier, R. Routley, K. Row, A. Rowbottom, R. Rowe, C. Rowe, M. Rowe, S. Rowein, D. Rowley, M. Rowley, R. Rowsell, C. Rowsell, A. Rowsell, P. Rowsell, F. Roxas, D. Roy, B. Roy, S. Roy, A. Roy, R. Roy, C. Roy, D. Royston, R. Rucks, Z. Ruda, V. Ruddy, D. Rudkevitch, K. Rudolf, C. Rudolph, K. Rudra, K. Ruecker, L. Ruesga, S. Ruether, M. Ruetz, D. Rueve, I. Rugg, M. Ruggles, M. Ruiz, S. Rumball, D. Rumbolt, T. Rumbolt, J. Rumjan, D. Rumohr, M. Rundle, J. Rusk, N. Rusk, T. Rusnak, D. Russell, C. Russell, P. Russell, S. Russell, J. Russell, E. Russell, T. Russell, R. Rustad, D. Rutberg, B. Rutherford, S. Rutherford, J. Rutherford, M. Rutherford, D. Rutley, M. Rutter, T. Ruttle, H. Rutz, C. Ruzycki, N. Rvachew, F. Rwirangira, J. Ryalls, C. Ryan, M. Ryan, A. Ryan, K. Ryan, D. Ryan, T. Ryan, S. Ryback, R. Rybchinsky, D. Ryder, C. Ryder, J. Ryll, C. Rymut, A. Ryzebol, E. Saar, R. Saastad, J. Saastad, R. Sabas, M. Sabo, A. Sabourov, J. Sachs, F. Sackey-Forson, N. Sacrey, S. Sacrey, V. Sacrey, J. Sacrey, J. Saeed, E. Saenz de Santa Maria, J. Sagan, S. Sagrafena, A. Saha, K. Sahni, S. Sahoo, A. Saini, P. Saini, J. Sair, M. Sair, K. Saiyed, K. Sakowsky, R. Sakwattanapong, A. Salakunov, A. Salaudeen, A. Salazar, D. Salazar, C. Salazar, E. Salazar, N. Salazar, A. Saleh, O. Saleh, M. Salehi, J. Sali, M. Salman, E. Salmon, A. Salonga, S. Saltwater, B. Saluk, J. Salvador, R. Salyn, C. Salzl, A. Samadi, A. Samarathunge, S. Samida, M. Samimi, K. Samms, A. Samoisette, D. Sampang, J. Sampang, S. Sampanthamoorthy, J. Sampson, T. Sampson, R. Sampson, H. Sampson, R. Samson, B. Samson, T. Samuelson, S. Samy, V. Sanchala, M. Sanchez, E. Sanchez, R. Sanchez Hernandez, P. Sanders, T. Sanders, M. Sanders, S. Sanderson, D. Sanderson, I. Sanderson, L. Sanderson, S. Sandhar, J. Sandie, G. Sando, T. Sanelli, G. Sanford, N. Sanftleben, J. Sangha, E. Sangroniz, N. Sankaran, J. Sanmiguel, L. Sanoko, M. Santarossa, T. Santos, M. Santucci, J. Sanyal, R. Sarabin, J. Sarai, Z. Saran, S. Saran, A. Saran, R. Sarauskas, A. Sarawanski, M. Sarbah, D. Saretsky, M. Saric, I. Sarjeant, S. Sarkar, D. Sarmiento, A. Saroop, A. Sartori, M. Sartoris, M. Sas, S. Sashuk, B. Sather, T. Sather, W. Sather, M. Satra, H. Sattar, J. Saucier, E. Saucier, E. Saulnier, L. Saunders, M. Saunders, G. Saunders, R. Saunders, S. Saurette, C. Sauve, J. Savage, C. Savard, F. Savaria, B. Savla, M. Savoie, D. Savoie, C. Savostianik, A. Savtchenko, S. Sawchuk, B. Sawler, A. Saxena, D. Saxty, R. Sayer, C. Sayer, J. Sayer, E. Sayewich, K. Sayko, K. Scagliarini, R. Scammell, J. Scarfe, J. Scarff, B. Scarth, R. Schaap, T. Schable, K. Schachtel, B. Schade, D. Schaffer, B. Schamehorn, M. Schanzenbach, G. Schappert, T. Schatkoske, R. Schatschneider, C. Schaub, P. Schaub, J. Schechtel, J. Schedlosky, C. Scheerschmidt, S. Schell, A. Schell, S. Schellenberg, L. Schelske, L. Scheper, C. Scherger, K. Scherger, C. Scheu, S. Schick, D. Schick, J. Schick, A. Schill, J. Schiller, C. Schiller, L. Schiller, A. Schindel, R. Schlachter, G. Schlamp, D. Schledt, H. Schleedoorn, D. Schlosser, D. Schmaltz, L. Schmaus, R. Schmidt, J. Schmidt, K. Schmidt, N. Schmidt, T. Schmidt, A. Schmidt, P. Schmuland, H. Schnaier, S. Schneider, P. Schneider, M. Schneider, G. Schneider, D. Schneider, K. Schneider, S. Schnell, K. Schnell, C. Schnepf, A. Schnick, R. Schnieder, J. Schnieder, D. Schnitzler, C. Schnurer, J. Schoengut, N. Schofield, S. Schofield, E. Schofield, R. Schonheiter, L. Schonhoffer, R. Schram, R. Schroeder, S. Schroeder, K. Schroeder, R. Schuh, N. Schuler, E. Schulte, S. Schultheiss, D. Schultz, S. Schultz, P. Schultz, J. Schultz, C. Schultz, M. Schultze, T. Schulz, K. Schumacher, R. Schwank, D. Schwank, B. Schwartz, D. Schwarz, T. Schwengler, C. Schwenning, L. Schwetz, J. Schwindt, T. Scimia, M. Scipior, R. Scoles, J. Scollard, G. Scott, J. Scott, R. Scott, M. Scott, C. Scott, E. Scott, S. Scott, K. Scott, D. Scott, R. Scoville, M. Scragg, R. Scrimshaw, J. Sculland, C. Scullion, S. Seabrook, M. Seafoot, S. Seafoot, K. Seaman, C. Sears, G. Seaton, T. Seaward, M. Sebastian, K. Seehagel, D. Seel, C. Seely, M. Seguin, J. Segynola, L. Sehn, K. Seidel, P. Seipp, K. Seitz, R. Sekel, B. Sekulich, E. Sekura, D. Selby, K. Self, D. Selinger, M. Selman, R. Selvarajan, D. Semaan, T. Semashkewich, A. Semchanka, L. Semeniuk, K. Seminchuk, R. Senecal, T. Senecal, T. Senger, P. Senk, T. Senner, H. Seo, F. Sepnio, A. Sequeira, R. Sereda, C. Sereda, N. Sereggela, B. Serfas, R. Serfas, P. Sergeant, D. Sergeant, J. Serino, E. Serniak, R. Serson, K. Setareh-Kokab, B. Severight, J. Seward, B. Sewell, C. Sexsmith, P. Sexton, S. Seyed Tarrah, G. Sgambaro, R. Sgambaro, M. Sgambaro, C. Shackleton, M. Shad, S. Shah, H. Shah, N. Shah, R. Shah, B. Shah, V. Shah, M. Shah, M. Shahebrahimi, S. Shahzad, S. Shaikh, K. Shakir, K. Shakotko, V. Shakouri, L. Shang, C. Shank, B. Shanmugam, J. Shannon, T. Shao, A. Sharifi, K. Sharma, T. Sharma, A. Sharma, R. Sharma, M. Sharman, N. Sharp, K. Sharpe, T. Sharpe, J. Sharpe, R. Sharron, R. Shaver, M. Shaw, K. Shaw, R. Shaw, E. Shaw, B. Shaw, O. Shaykina, K. Shea, L. Shea, R. Shea, B. Shearer, C. Shears, W. Sheaves, L. Sheaves, D. Sheaves, A. Shehata, M. Sheikh, K. Sheikh, O. Sheikh, C. Shen, B. Shenton, R. Shepel, I. Shepherd, M. Sheppard, G. Sheppard, D. Sheppard, T. Sheppard, R. Sheppard, P. Sheppard, C. Sheppard, J. Sheppard, C. Sherbanuk, A. Shergill, T. Sheridan, A. Sheriff, M. Sherman, S. Sherman, R. Sherman, A. Sherriffs, T. Sherwood, M. Sheth, N. Sheth, C. Sheward, J. Shewchuk, D. Shewchuk, L. Shi, A. Shideler, C. Shields, P. Shields, J. Shields, A. Shiers, N. Shihinski, S. Shiledarbaxi, K. Shill, P. Shiner, W. Shipley, J. Shire, V. Shirhatti, B. Shmoury, B. Shmyr, C. Shmyrko, M. Shobeiri, N. Shohel, R. Shonhiwa, T. Short, S. Short, D. Shortland, D. Shortreed, M. Shott, L. Shuai, M. Shukalov, T. Shukin, K. Shukla, D. Shular, J. Shumate, F. Shupenia, S. Shymoniak, D. Shypitka, J. Shysh, C. Sibeudu, I. Siddhanta, M. Siddiqui, A. Siddiqui, M. Sideroff, R. Sidloski, C. Sieben, D. Sieben, J. Sieben, E. Siemens, A. Sifton, R. Sigsworth, J. Sikora, W. Sikorski, L. Silas, R. Silbernagel, T. Silbernagel, B. Silue, N. Silue, L. Silva, I. Silva, J. Silva, J. Silver, D. Silverio, G. Silvis, R. Simard, C. Simard, K. Simard, D. Simard, D. Simbi, G. Simmelink, T. Simmonds, J. Simmons, C. Simms, A. Simms, F. Simms, R. Simms, M. Simoes, P. Simon, T. Simon, A. Simon, R. Simper, G. Simpkins, G. Simpson, S. Simpson, J. Simpson, C. Simpson, M. Simpson, W. Simpson, R. Simpson, D. Simpson, L. Simpson, C. Sims, E. Sinclair, D. Sinclair, S. Sinclair, R. Sinclair, D. Sine, K. Singh, A. Singh, S. Singh, H. Singh, Y. Singh, S. Singla, M. Sinkova-Hovdestad, A. Sinnett, L. Sinnicks, B. Sinnicks, S. Sison, R. Sison, J. Sjonnesen, D. Skanderup, W. Skaret, K. Skarra, E. Skarsen, B. Skinner, T. Skinner, M. Skinner, R. Skinner, M. Skipper, J. Skjeie, G. Skoczek, J. Skog, Z. Skoko, M. Skolski, R. Skrepnek, S. Skulmoski, M. Skulski, J. Skwara, M. Skyrpan, A. Slade, M. Slavin, K. Slemko, D. Slemp, A. Sleno, A. Slipchuk, J. Sloan, M. Sloan, R. Slobodian, K. Slotwinski, J. Sloychuk, S. Slywka, E. Smart, P. Smart, R. Smart, J. Smid, S. Smiegielski, C. Smillie, S. Smith, J. Smith, B. Smith, K. Smith, C. Smith, T. Smith, M. Smith, R. Smith, D. Smith, A. Smith, G. Smith, E. Smith, L. Smith, C. Smitham, L. Smollet, E. Smolyaninova, A. Smyl, R. Smyl, J. Sneddon, K. Snee, T. Snell, J. Snider, G. Snider, I. Snook, J. Snow, K. Snow, W. Snow, J. Snowdon, D. Snowdon, D. Snyder, J. Soar, J. Soenen, D. Sohlbach, D. Sokoloski, K. Solanki, S. Solanki, J. Solano, J. Soley, V. Sollid, M. Sollows, S. Soloshy, A. Soloway, K. Soltys, L. Somerville, L. Sommer, W. Sommerfeld, R. Somorai, D. Soni, A. Sonpal, N. Soodyall, W. Sookram, M. Soolagallu, T. Sopatyk, G. Sopczak, R. Sorensen, L. Sorge, I. Soro, L. Sorochan, C. Sorochan, D. Soroko, M. Soucy, L. Soucy, R. Soucy, L. Soutar, J. Southern, H. Sow, E. Spagrud, D. Spagrud, D. Spanics, M. Sparks, E. Spearman, B. Speedtsberg, G. Speer, S. Spencer, R. Spencer, D. Spencer, B. Spendiff, D. Spidell, K. Spiker, A. Spohn, C. Sporidis, M. Spreacker, M. Sprinkle, K. Sproule, C. Spurr, N. Spurrell, E. Spurrell, A. Spurrell, P. Spurvey, R. Spychka, N. Squarek, J. Squire, T. Squires, P. Squires, R. Sran, E. Sribney, A. Sriram, S. St. Croix, P. St. Denis, R. St. Jean, B. St. Jean, R. St. Martin, J. St. Onge, E. St. Pierre, M. St. Pierre, R. St. Pierre, K. Stacey, C. Stacey, A. Stacey, I. Stacey-Salmon, P. Stackhouse, S. Stadnichuk, G. Stadnichuk, S. Stadnyk, J. Stagg, D. Stagg, T. Stagg, K. Stagg, M. Stainthorpe, K. Stairs, J. Stajkowski, M. Stalker, R. Stamp, B. Stamp, A. Stan, A. Standing, J. Stanford, R. Stang, M. Stang, R. Stanger, M. Stangl, J. Stanley, J. Staples, A. Staples, P. Stapleton, K. Stark, L. Stark, R. Staruiala, R. Stasiuk, D. Staszewski, S. Stauth, A. Stavropoulos, K. Stawins-

ki, E. Stearns, M. Stebner, M. Stec, R. Steele, L. Steeves, B. Steeves, S. Stefan, T. Stefansson, A. Stefura, M. Stein, M. Steinbach, J. Steinkey, S. Steinkey, A. Stella, D. Stemmann, B. Stengler, W. Stenhouse, M. Stephens, T. Stephens, J. Stephenson, B. Stephenson, L. Stephenson, G. Stetar, R. Stevens, G. Stevens, N. Stevens, D. Stevens-Dicks, A. Stevens-Dicks, A. Stevenson, M. Stevenson, R. Stevenson, H. Stevenson, N. Stevenson, T. Stevers, R. Steward, J. Stewart, I. Stewart, D. Stewart, T. Stewart, R. Stewart, C. Stewart, B. Stich, W. Stickel, G. Stickelmier, R. Stieben, M. Stiefel, D. Stinn, S. Stirling, M. St-Jacques, M. Stobart, D. Stobbe, J. Stober, M. Stockes, C. Stocking, M. Stockton, C. Stoddard, J. Stokes, S. Stoller, T. Stolz, C. Stolz, D. Stone, T. Stone, M. Stone, M. Stordahl, J. Storey, D. Stormo, B. Stortz, D. Stout, R. Stoutenberg, D. Stoyles, S. Strachan, A. Stranaghan, R. Stranberg, W. Strand, C. Strand, J. Strandquist, R. Strang, C. Strang, D. Strankman, N. Strantz, B. Stratichuk, D. Stratmoen, M. Straughan, M. Street, S. Street, W. Stretch, R. Stretch, R. Strickland, H. Strickland, J. Strilchuk, M. Stroh, J. Strong, R. Strong, M. Stronski, R. Struski, D. Strynadka, D. Stuart, L. Stuart, P. Stuart, C. Stubbs, G. Stuber, V. Stuckey, T. Stuckless, N. Stuckless, R. Stuckless, J. Stuebing, G. Sturdy, F. Sturge, J. Sturge, P. Sturge, P. Sturgeon, J. Sturgeon, D. Sturrock, A. Styles, W. Su, L. Su, M. Suarez, V. Subasic, I. Subasinghe, V. Subban, J. Subramaniam, R. Subramaniam, B. Suchan, S. Suche, A. Suhel, R. Sukkel, J. Sukoveoff, T. Sullivan, R. Sullivan, J. Sullivan, M. Sullivan, P. Sultanian, B. Summerfelt, E. Summers, C. Summers, E. Sumner, T. Sun, X. Sun, U. Sundar, U. Sundaram, P. Sundaravadivelu, C. Surgenor, G. Surugiu, A. Surugiu, T. Sutcliffe, C. Sutherland, L. Sutherland, D. Sutherland, K. Sutherland, C. Suttie, P. Sutton, B. Sutton, S. Sverdahl, T. Svoboda, A. Swain, D. Swain, S. Swain, T. Swallow, D. Swan, M. Swan, J. Swannack, J. Swanson, C. Swanson, N. Swanson, R. Swarnkar, E. Sweeney, S. Sweetapple, C. Swenarchuk, N. Swennumson, E. Switzer, A. Sychak, K. Sydorko, D. Syed, C. Syed, W. Syed, J. Sykes, T. Sylvester, D. Sylvestre, G. Sylvestre, B. Symington, M. Symons, A. Symons, T. Sypher-Michel, D. Syrnyk, G. Sywake, N. Szalay, E. Szeto, C. Szmata, A. Szoke, C. Szpecht, D. Sztym, S. Szubzda, C. Szutiak, K. Szydlik, V. Ta, J. Ta, C. Tacadena, M. Tade, D. Taggart, A. Taghipour, V. Tai, P. Taiani, M. Tainsh, D. Tainton, D. Tait, O. Tait, G. Tait, J. Taite, A. Tajik, D. Tajiri, D. Takala, S. Takala, G. Talati, S. Talati, J. Talbot, C. Talbot, M. Talerico, C. Tallack, D. Tallas, B. Talma, K. Tam, N. Taman, B. Tamas, D. Tames Jara, S. Tan, K. Tan, B. Tan, C. Tan, M. Tanasescu, B. Tancowny, L. Tang, X. Tang, G. Tangonan, T. Tanigami, J. Tanner, M. Tapley, G. Tapp, C. Tarache, A. Tarasenco, R. Tarasoff, C. Tardif, G. Tarditi, B. Tarkowski, M. Taron, H. Tarraf, D. Tarrant, B. Tasek, J. Tatarin, R. Tatro, N. Tavassoli, M. Taylor, W. Taylor, G. Taylor, K. Taylor, L. Taylor, R. Taylor, A. Taylor, N. Taylor, P. Taylor, B. Taylor, S. Taylor, J. Taylor, C. Taylor, H. Taylor, J. Taylor-Kay, B. Teare, C. Tearoe, M. Teeple, P. Teha, J. Teixeira, S. Tejpar, A. Telan, M. Teleptean, R. Tellier, B. Temesgen, J. Temple, C. Templeton, S. Tenhunen, L. Tennant, K. Tenney, J. Teppin, G. Teske, C. Tessier, L. Tessier, W. Teszeri, W. Tetachuk, C. Tetreau, J. Tettensor, B. Tetz, J. Tetz, S. Tetz, I. Tewfik, F. Thaddaues, L. Thai, T. Tham, P. Thannhauser, J. Thauberger, J. Theis, S. Theoret, G. Theriault, G. Therrien, B. Thevarajah, W. Thew, R. Thibodeau, R. Thiessen, T. Thiessen, C. Thiessen, J. Thiessen, W. Thijs, M. Thoen, D. Thomas, S. Thomas, P. Thomas, L. Thomas, E. Thomas, M. Thomas, J. Thomas Cotton, T. Thomassen, J. Thompson, A. Thompson, R. Thompson, K. Thompson, E. Thompson, H. Thompson, C. Thompson, L. Thompson, I. Thompson, T. Thompson, S. Thompson, J. Thomsen, P. Thomsen, S. Thomson, P. Thomson, K. Thomson, M. Thomson, T. Thomson, A. Thomson, J. Thomson, W. Thomson, K. Thorburn, W. Thorburne, T. Thorburne, J. Thorleifson, B. Thorn, D. Thorne, L. Thorne, B. Thornhill, E. Thornton, K. Thornton, N. Thorp, K. Thors, K. Threndyle, E. Thunaes, D. Thurman, M. Thyer, T. Tian, M. Tiedje, S. Tieh, P. Tieu, B. Tiffin, T. Tilbury, D. Tillapaugh, J. Tiller, M. Tilley, K. Tilley, D. Tilley, K. Tillotson, T. Tillotson, S. Timothy, N. Tindall, M. Tineo, D. Tipper, A. Tishchenko, B. Titus, D. Tiwary, R. Tiwary, C. Tkach, D. Tkachuk, K. Tobin, C. Tobin, V. Tobin, B. Tobin, K. Tobler, S. Todd, C. Todd, B. Todd, W. Todoschuk, T. Tolen, D. Tomar, V. Tomashewsky, G. Tomchuk, B. Tomchuk, D. Tomiuk, K. Tomlinson, C. Tomlinson, B. Tompkins, C. Tomsett, A. Tomszak, N. Tomte, L. Tong, W. Tong, T. Tonge, M. Tonon, S. Tookey, A. Toop, V. Topacio, S. Topolnitsky, K. Tordon, L. Torrance, P. Torrance, C. Torraville, J. Torraville, F. Torraville, N. Torres, D. Touchette, S. Touchette, D. Toullelan, T. Tourand, M. Townsend, D. Tozer, O. Tozser, A. Tran, J. Tran, C. Tran, D. Tran, M. Trang, C. Trapp, G. Trask, L. Trautman, M. Travers, P. Traverse, J. Tredger, G. Treen, J. Treen, W. Trelinski, J. Trelinski, J. Treliving, L. Tremblay, M. Tremblay, W. Tremblett, C. Tremblett, S. Tremel, J. Trenholm, A. Trentham, D. Trentham, J. Trieu, J. Trieu-Ly, J. Trifaux, S. Trifonov, W. Trigger, A. Trinh, D. Trinh, J. Trinier, E. Triumbari, C. Troake, B. Troy, P. Troy, J. Trto, R. Trudeau, J. Trudeau, B. Trumpf, A. Truong, H. Truong, S. Truong, H. Tsagalas, Y. Tse, C. Tse, M. Tsineli, D. Tsui, Y. Tu, A. Tuck, B. Tucker, R. Tucker, D. Tucker, J. Tucker, R. Tuerke, A. Tuico, D. Tuite, S. Tulan, B. Tulk, J. Tulk, B. Tulloch, N. Tulloch, B. Tumbach, P. Tung, M. Tunke, T. Tupper, T. Turbide, D. Turcotte, J. Turcotte, T. Turgeon, D. Turgeon, S. Turner, C. Turner, B. Turner, D. Turner, J. Turner, D. Turpin, T. Turpin, V. Turska, S. Turton, S. Tutkaluk, S. Tuttle, R. Tuttle, I. Tutto, L. Tuttosi, T. Twist, P. Twomey, D. Twyne, O. Tyan, M. Tyler, A. Tyler, W. Tymchuk, D. Tymchyna, R. Tymchyna, N. Tynan, S. Tyrell, G. Tyrer, C. Tyssen, J. Uddin, S. Udupa, D. Uduwara Merennage, T. Uhrich, S. Ulloa, C. Ulrich, E. Ulrich, J. Umali, O. Umana, U. Umoh, A. Umpleby, L. Underhill, N. Underwood, R. Underwood, K. Underwood, T. Ung, B. Unrath, L. Unrau, P. Unruh, H. Unruh, S. Upadhyay, M. Upadhyay, U. Upadhyaya, C. Upham, M. Uponi, D. Urban, L. Urbina, J. Urdaneta, C. Urlacher, A. Ustariz, P. Uwabor, K. Uyanwune, R. Vachon, S. Vadnai, K. Vaideswaran, M. Vajdik, G. Valencia, A. Valentine, D. Valin, T. Valin, A. Valiquette, G. Valiquette, J. Valle, M. Vallee, L. Vallee, W. Vallee, G. Vallis, A. Valmadrid, K. Van Buskirk, C. Van de Reep, A. Van De Reep, W. Van den Oever, M. van der Burgh, V. Van Der Merwe, N. Van Der Merwe, A. Van Donkervoort, H. Van Dyck, M. Van Dyk, N. Van Dyke, B. van Dyke, P. van Eerde, J. Van Es, D. Van Genne, L. Van Genne, L. van Heerden, S. Van Jaarsveld, J. Van Nes, C. van Niekerk, F. Van Overloop, S. Van Rensburg, D. Van Rootselaar, C. Van Schoor, K. van Son, R. Van Steinburg, R. van Zanden, M. Vanberg, D. Vanbocquestal, M. Vance, J. Vancoughnett, K. Vandaelle, J. Vandeligt, T. Vandemark, R. Vandemark, D. Vandenberg, G. Vander Veen, N. Vandergriend, J. Vanderkley, T. Vandermeer, A. Vandersalm, J. Vandervoort, G. van't Wout, C. Vare, L. Varela Avendano, S. Varey, M. Varga, D. Varty, N. Vaschetto, A. Vashisht, C. Vasquez, A. Vasquez, M. Vasquez-Placid, J. Vasseur, R. Vassov, A. Vaters, R. Vaudan, N. Vaughan, J. Veale, O. Vedmedenko, F. Veenbaas, S. Vekved, B. Velagapudi, B. Velichka, M. Velmurugan, S. Venkatesh, G. Venkateshvaralu, R. Venn, D. Venning, J. Vera, L. Verbaas, D. Verbeek, D. Verbicky, M. Verburg, J. Verge, A. Verge, M. Verge, S. Veroba, J. Verot, B. Verreau, D. Versnick-Brown, S. Vetsch, K. Veysey, J. Vezina, C. Viana, G. Vibert, J. Vicic, N. Vick, D. Vickery, K. Vierboom, A. Vihristencu, G. Viljoen, R. Villanueva, J. Villemaire, M. Villemaire, C. Villemere, P. Villeneuve, R. Vincent, K. Vincent, R. Vindevoghel, S. Vineham, R. Vinkle, K. Virus, A. Visotto, R. Vivian, N. Vizcuna Alvarado, R. Vloet, S. Voight, B. Volkmann, R. Volkmann, J. Vollman, W. Volschenk, L. Vondermuhll, B. Von-Grat, A. Vosburgh, A. Votta, A. Vredegoor, J. Vrolson, Q. Vuong, L. Vuong, J. Vuong, G. Wack, T. Waddell, E. Waddell, K. Waddy, W. Wade, J. Wade, T. Wagil, C. Wagner, J. Wagner, N. Wagner, D. Wagner, K. Wagner, G. Wagner, M. Wahl, N. Waite, F. Wajih, D. Wakaruk, L. Wakaruk, T. Wakulchyk, A. Walchuk, J. Waldick, D. Waldner, D. Waldo, K. Waldron, A. Walintschek, S. Walker, R. Walker, T. Walker, D. Walker, J. Walker, G. Walker, C. Walker, K. Walko, S. Wall, D. Wall, K. Wallace, E. Wallace, V. Wallace, C. Wallace, H. Wallace, A. Wallace, D. Wallace, G. Wallin, N. Wallin, M. Wallis, V. Wallwork, T. Walraven, W. Walsh, B. Walsh, S. Walsh, E. Walsh, M. Walsh, R. Walsh, A. Walsh, T. Walsh, P. Walsh, L. Walter, D. Walters, J. Walters, A. Walters, I. Walton, K. Wambolt, N. Wan, D. Wanchuk, T. Wang, X. Wang, Y. Wang, J. Wang, R. Wang, L. Wang, W. Wang, H. Wang, C. Wang, S. Wang, P. Wang, Z. Wang, B. Wangler, D. Wannas, L. Waquan, S. Waquan, T. Warburton, E. Ward, R. Ward, K. Ward, B. Warehime, D. Warford, W. Warholik, J. Waring, C. Wark, W. Warman, F. Warraich, S. Warren, G. Warren, J. Warren, R. Warren, K. Warren, D. Warrington, M. Warsame, K. Warwaruk, J. Washburn, M. Washington, A. Wasikowski, P. Wassell, C. Wasylciw, W. Wasylucha, S. Waterfield, D. Waterfield, C. Waters, M. Watson, J. Watson, G. Watson, D. Watson, K. Watson, S. Watson, G. Watt, D. Watt, B. Watton, J. Watts, B. Watts, T. Wawro, D. Weatherby, B. Weatherby, C. Weatherhead, H. Weaver, L. Weaving, G. Webb, A. Webb, P. Webb, R. Webb, B. Webber, J. Webber, D. Webber, O. Websdale, K. Webster, D. Weed, E. Weening, E. Weenink, B. Wegenast, Z. Wei, B. Wei, J. Weibrecht, J. Weigl, J. Weik, D. Weimer, C. Weingarten, R. Weir, G. Weisbeck, R. Weisbrot, M. Weishaar, C. Weiss, J. Weller, P. Weller, M. Wellman, B. Wellman, C. Wells, T. Wells, E. Wells, N. Wells, R. Wells, D. Wells, L. Wells, A. Wells, K. Wellwood, A. Welsh, J. Welsh, W. Welte, W. Welygan, Z. Wen, G. Weng, M. Wenger, P. Wenger, J. Wenisch, G. Wennberg, J. Wentworth, A. Wentworth, K. Wenzel, D. Werbowy, D. Werle, C. Werner, N. Wert, B. Weslake, E. Wessel, R. West, D. West, M. Westad, D. Westbrook, K. Westland, B. Wetthuhn, L. Wheating, D. Wheating, S. Wheaton, J. Wheaton, N. Wheeler, J. Wheeler, L. Wheeler, C. Wheeler, K. Wheeler, B. Wheeler, A. Wheeler, K. Whelan, C. Whelan, R. Whelan, D. Whelan, R. Whelan-Maloney, G. Whelen, L. Whillans, A. White, P. White, R. White, S. White, M. White, T. White, H. White, G. White, Z. White, N. White, F. White, B. White, J. White, D. White, L. Whitehead, V. Whitehead, T. Whitehead, J. Whitehead, D. Whitehouse, N. Whiteknife, K. Whiteknife, J. Whitelaw, C. Whiteley, A. Whiteside, C. Whitford, B. Whiting, R. Whitman, H. Whitmore, K. Whitney, M. Whittaker, H. Whitten, A. Whitten, D. Whitty, A. Whitwell, A. Wickins, C. Wickwire, G. Wideman, M. Widing, N. Wiebe, M. Wiebe, D. Wiebe, A. Wiebe, T. Wiebe, R. Wiege, T. Wielgus, B. Wiesener, C. Wietzel, Z. Wigglesworth, T. Wight, S. Wight, D. Wijesingha, D. Wilbee, C. Wilbee, A. Wilcott, J. Wilcox, M. Wilcox, R. Wild, D. Wilde, E. Wildeman, R. Wiles, D. Wiles, C. Wilk, T. Wilk, C. Wilkes, C. Wilkin, D. Wilkins, J. Wilkinson, K. Wilkinson, P. Will, D. Willard, E. Willard, B. Willburn, A. Willcott, B. Willcott, J. Willems, R. Willey, C. Willey, B. Williams, T. Williams, A. Williams, M. Williams, D. Williams, G. Williams, C. Williams, L. Williams, N. Williams, W. Williams, K. Williamson, M. Williamson, D. Williamson, C. Williamson, J. Williamson, J. Willick, R. Willis, M. Willis, S. Williscroft, J. Williston, D. Willms, S. Wills, C. Willson, D. Willson, M. Willschut, D. Wilson, S. Wilson, J. Wilson, C. Wilson, W. Wilson, M. Wilson, L. Wilson, G. Wilson, A. Wilson, H. Wilson, K. Wilson, R. Wilson, A. Winfield, B. Wingate, A. Wingert, J. Winia, B. Winiarz, I. Winland, R. Winnicky, T. Winquist, R. Winslow, O. Winsor, J. Winsor, A. Winter, T. Winter, C. Winterhalt, G. Winters, R. Winters, J. Wirachowsky, G. Wirachowsky, T. Wire, W. Wiseman, M. Wiseman, P. Wiseman, I. Wishart, N. Withers, M. Witmer, Z. Witt, B. Wittenborn, C. Wlad, A. Wlos, M. Woehleke, J. Woitas, D. Woitas, T. Woitte, R. Wojtowicz, S. Wolf, D. Wolfe, J. Wolfe, D. Wollum, C. Woloshyn, J. Wolstenholme, B. Wolstoncroft, J. Wolter, R. Wolters, M. Wong, J. Wong, L. Wong, A. Wong, N. Wong, K. Wong, C. Wong, L. Woo, C. Woo, J. Woo, P. Wood, G. Wood, R. Wood, L. Wood, A. Wood, R. Woodburne, J. Woodd, M. Woodfin, S. Woodfine, N. Woodford, S. Woodford, T. Woodford, A. Woodger, M. Woodhead, C. Woodhead, J. Woods, D. Woods, T. Woods, M. Woodske, J. Wooldridge, B. Wooley, S. Woolfitt, T. Woolley, R. Woolner, R. Wootton, M. Workman, M. Workun, M. Woroniuk, C. Worthman, P. Wortman, H. Wossey Ogandaga Mbourou, J. Wotten, B. Woytenko, T. Wozney, C. Wright, L. Wright, B. Wright, R. Wright, G. Wrinn, B. Wu, D. Wu, H. Wu, J. Wu, M. Wu, C. Wu, P. Wuorinen, B. Wurzer, K. Wutzke, E. Wylie, G. Wyman, G. Wyndham, D. Wyshynski, L. Wysocki, S. Wytrychowski, Y. Xia, Y. Xie, J. Xu, Q. Xu, Z. Xu, M. Xue, D. Yackel, N. Yagolnyk, K. Yakemchuk, K. Yakimowich, L. Yakiwchuk, J. Yamniuk, D. Yang, L. Yang, D. Yanke, M. Yanota, G. Yanota, W. Yao, L. Yao, K. Yao, H. Yare, A. Yaremko, R. Yarmuch, J. Yaroslawsky, S. Yasin, M. Yaychuk, P. Yazdani, B. Ye, B. Yeboue, R. Yee, G. Yee, B. Yee, C. Yen, C. Yeoman, D. Yep, P. Yepes, J. Yeremiy, J. Yeske, Y. Ying, O. Ying, C. Ying, L. Yip, K. Yip, J. Yip, M. Yniguez, F. Yohannes, R. Yong, J. Yoo, P. York, F. York, A. Yoshikawa, X. You, D. Youck, M. Youell, M. Young, L. Young, B. Young, D. Young, E. Young, T. Young, P. Young, S. Young, C. Young, J. Young, K. Young, N. Younis, P. Youssef, R. Yowney, J. Yu, G. Yu, E. Yu, C. Yuen, J. Yuill, D. Yuill, R. Yuristy, R. Zabek, A. Zabloski, A. Zacharias, C. Zacharias, T. Zachoda, C. Zackowski, N. Zaderey, J. Zaderey, N. Zadko, B. Zagoruy, S. Zagozewski, E. Zahacy, A. Zahorszky, B. Zaitsoff, D. Zambrano Suarez, R. Zamudio Baca, B. Zandstra, D. Zanoni, C. Zaparyniuk, M. Zarowny, Z. Zarowny, K. Zarowny, G. Zarowny, D. Zarowny, S. Zawada, K. Zayac, R. Zazula, D. Zazula, S. Zbrodoff, K. Zeer, T. Zeiser, I. Zelazny, D. Zelman, B. Zembik, D. Zemlak, A. Zenide, W. Zeniuk, G. Zeran, J. Zerpa, K. Zerr, M. Zerr, S. Zgurski, Y. Zhai, B. Zhang, Z. Zhang, J. Zhang, Y. Zhang, X. Zhang, M. Zhang, Q. Zhang, W. Zhang, B. Zhao, R. Zhao, L. Zhao, W. Zheng, G. Zheng, S. Zheng, Y. Zhou, H. Zhou, Q. Zhou, L. Zhu, W. Zhu, E. Zhuromsky, P. Zia, S. Ziadeh, C. Ziebart, A. Zielke, D. Zilinski, D. Zimmer, E. Zimmer, C. Zimmerman, R. Zoerb, A. Zoglauer, L. Zseder, A. Zubot, J. Zuk, S. Zukanovic, N. Zukiwski, S. Zukowski, J. Zwolak, S. Zwyer, S. Zyha

2019 Year-End Reserves

DETERMINATION OF RESERVES

For the year ended December 31, 2019, the Company retained Independent Qualified Reserves Evaluators (IQREs), Sproule Associates Limited, Sproule International Limited and GLJ Petroleum Consultants Limited, to evaluate and review all of the Company's proved and proved plus probable reserves. The evaluation and review was conducted and prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with the IQREs as to the Company's reserves. All reserves values are Company Gross unless stated otherwise.

- Canadian Natural's 2019 performance has resulted in another year of excellent finding and development costs:
  - Finding, Development and Acquisition ("FD&A") costs, excluding changes in Future Development Costs ("FDC"), are $4.52/BOE for proved reserves and $5.34/BOE for proved plus probable reserves.
  - FD&A costs, including changes in FDC, are $7.45/BOE for proved reserves and $5.75/BOE for proved plus probable reserves.
- Proved reserves increased 11% to 10.993 billion BOE with reserves additions and revisions of 1.501 billion BOE. Proved plus probable reserves increased 6% to 14.252 billion BOE with reserves additions and revisions of 1.271 billion BOE.
- Proved reserves additions and revisions replaced 2019 production by 374%. Proved plus probable reserves additions and revisions replaced 2019 production by 317%.
- The proved BOE reserves life index is 27.8 years and the proved plus probable BOE reserves life index is 36.0 years.
- Proved developed producing reserves additions and revisions are 0.778 billion BOE, replacing 2019 production by 194%. The total proved developed producing BOE reserves life index is 20.2 years.
- The net present value of future net revenues, before income tax, discounted at 10%, increased 1% to $107.6 billion for proved reserves and decreased 2% to $127.8 billion for proved plus probable reserves. The net present value for proved developed producing reserves is relatively unchanged at $84.3 billion.

Summary of Company Gross Reserves
As of December 31, 2019
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	97	103	235	653	6,219	3,150	92	7,925
Developed Non-Producing	12	14	—	14	—	162	6	72
Undeveloped	56	85	58	1,771	133	3,083	177	2,794
Total Proved	165	202	293	2,438	6,352	6,395	275	10,791
Probable	64	91	132	1,670	545	3,118	133	3,156
Total Proved plus Probable	229	293	425	4,108	6,897	9,513	408	13,947
North Sea								
Proved								
Developed Producing	37					10		39
Developed Non-Producing	4					1		4
Undeveloped	68					5		69
Total Proved	109					16		112
Probable	67					5		68
Total Proved plus Probable	176					21		179
Offshore Africa								
Proved								
Developed Producing	32					29		37
Developed Non-Producing	12					6		13
Undeveloped	39					13		41
Total Proved	83					48		91
Probable	31					24		35
Total Proved plus Probable	114					72		126
Total Company								
Proved								
Developed Producing	166	103	235	653	6,219	3,189	92	8,001
Developed Non-Producing	28	14	—	14	—	169	6	90
Undeveloped	163	85	58	1,771	133	3,101	177	2,903
Total Proved	357	202	293	2,438	6,352	6,460	275	10,993
Probable	162	91	132	1,670	545	3,147	133	3,258
Total Proved plus Probable	519	293	425	4,108	6,897	9,607	408	14,252

Reconciliation of Company Gross Reserves
As of December 31, 2019
Forecast Prices and Costs

PROVED	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
December 31, 2018	194	182	305	1,540	6,091	6,597	267	9,679
Discoveries	—	—	—	—	—	—	—	—
Extensions	3	6	—	17	385	112	11	440
Infill Drilling	5	5	—	—	—	206	8	52
Improved Recovery	—	—	—	237	—	2	—	238
Acquisitions	2	46	—	769	—	35	1	823
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(3)	(3)	(3)	—	—	(228)	(5)	(53)
Technical Revisions	(16)	(3)	12	(64)	20	198	11	(8)
Production	(19)	(30)	(21)	(61)	(144)	(527)	(16)	(380)
December 31, 2019	**165**	**202**	**293**	**2,438**	**6,352**	**6,395**	**275**	**10,791**
North Sea								
December 31, 2018	119					27		124
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	(2)					—		(2)
Technical Revisions	2					(2)		2
Production	(10)					(9)		(12)
December 31, 2019	**109**					**16**		**112**
Offshore Africa								
December 31, 2018	86					28		90
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	5					29		10
Production	(8)					(9)		(9)
December 31, 2019	**83**					**48**		**91**
Total Company								
December 31, 2018	399	182	305	1,540	6,091	6,652	267	9,893
Discoveries	—	—	—	—	—	—	—	—
Extensions	3	6	—	17	385	112	11	440
Infill Drilling	5	5	—	—	—	206	8	52
Improved Recovery	—	—	—	237	—	2	—	238
Acquisitions	2	46	—	769	—	35	1	823
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(5)	(3)	(3)	—	—	(228)	(5)	(54)
Technical Revisions	(9)	(3)	12	(64)	20	225	11	3
Production	(37)	(30)	(21)	(61)	(144)	(544)	(16)	(401)
December 31, 2019	**357**	**202**	**293**	**2,438**	**6,352**	**6,460**	**275**	**10,993**

Reconciliation of Company Gross Reserves
As of December 31, 2019
Forecast Prices and Costs

PROVED PLUS PROBABLE	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
December 31, 2018	268	252	445	3,059	7,032	9,633	397	13,058
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	12	—	26	—	177	17	89
Infill Drilling	6	7	—	—	—	476	15	108
Improved Recovery	—	—	—	329	—	3	—	329
Acquisitions	2	68	—	955	—	42	1	1,033
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(4)	(3)	(3)	—	—	(266)	(6)	(60)
Technical Revisions	(29)	(12)	4	(198)	9	(26)	(1)	(230)
Production	(19)	(30)	(21)	(61)	(144)	(527)	(16)	(380)
December 31, 2019	**229**	**293**	**425**	**4,108**	**6,897**	**9,513**	**408**	**13,947**
North Sea								
December 31, 2018	186					38		193
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	—					(9)		(2)
Production	(10)					(9)		(12)
December 31, 2019	**176**					**21**		**179**
Offshore Africa								
December 31, 2018	121					63		131
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	—					18		3
Production	(8)					(9)		(9)
December 31, 2019	**114**					**72**		**126**
Total Company								
December 31, 2018	575	252	445	3,059	7,032	9,734	397	13,382
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	12	—	26	—	177	17	89
Infill Drilling	6	7	—	—	—	476	15	108
Improved Recovery	—	—	—	329	—	3	—	329
Acquisitions	2	68	—	955	—	42	1	1,033
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(4)	(3)	(3)	—	—	(266)	(6)	(60)
Technical Revisions	(28)	(12)	4	(198)	9	(16)	(1)	(228)
Production	(37)	(30)	(21)	(61)	(144)	(544)	(16)	(401)
December 31, 2019	**519**	**293**	**425**	**4,108**	**6,897**	**9,607**	**408**	**14,252**

NOTES TO RESERVES:

1. Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.
2. Information in the reserves data tables may not add due to rounding. BOE values and oil and gas metrics may not calculate exactly due to rounding.
3. Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserves estimates were provided by Sproule Associates Limited:

	2020	2021	2022	2023	2024
Crude oil and NGL					
WTI at Cushing (US$/bbl)	61.00	65.00	67.00	68.34	69.71
Western Canada Select (C$/bbl)	59.81	63.98	63.77	65.04	66.34
Canadian Light Sweet (C$/bbl)	73.84	78.51	78.73	80.30	81.91
Cromer LSB (C$/bbl)	73.84	77.51	77.73	79.30	80.91
Edmonton Pentanes+ (C$/bbl)	76.32	80.52	80.00	81.68	83.38
North Sea Brent (US$/bbl)	65.00	68.00	70.00	71.40	72.83
Natural gas					
AECO (C$/MMBtu)	2.04	2.27	2.81	2.89	2.98
BC Westcoast Station 2 (C$/MMBtu)	1.54	1.87	2.41	2.49	2.58
Henry Hub (US$/MMBtu)	2.80	3.00	3.25	3.32	3.38

   All prices increase at a rate of 2%/year after 2024.

   A foreign exchange rate of 0.7600 US$/C$ for 2020, 0.7700 US$/C$ for 2021 and 0.8000 US$/C$ after 2021 was used in the 2019 evaluation.

4. A barrel of oil equivalent (“BOE”) is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.
5. Oil and gas metrics included herein are commonly used in the crude oil and natural gas industry and are determined by Canadian Natural as set out in the notes below. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies and may be misleading when making comparisons. Management uses these metrics to evaluate Canadian Natural’s performance over time. However, such measures are not reliable indicators of Canadian Natural’s future performance and future performance may vary.
6. Reserves additions and revisions are comprised of all categories of Company Gross reserves changes, exclusive of production.
7. Reserves replacement or Production replacement ratio is the Company Gross reserves additions and revisions, for the relevant reserves category, divided by the Company Gross production in the same period.
8. Reserves Life Index is based on the amount for the relevant reserves category divided by the 2020 proved developed producing production forecast prepared by the Independent Qualified Reserves Evaluators.
9. Finding, Development and Acquisition ("FD&A") costs excluding changes in Future Development Costs ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2019 by the sum of total additions and revisions for the relevant reserves category.
10. FD&A costs including changes in FDC are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2019 and net changes in FDC from December 31, 2018 to December 31, 2019 by the sum of total additions and revisions for the relevant reserves category. FDC excludes all abandonment, decommissioning and reclamation costs.
11. Abandonment, decommissioning and reclamation ("ADR") costs included in the calculation of the Future Net Revenue (“FNR”) for 2019 consist of both the Company's total Asset Retirement Obligation ("ARO"), before inflation and discounting, for development existing as at December 31, 2019 and forecast estimates of ADR costs attributable to future development activity.

Management's Discussion and Analysis

Table of Contents

Definitions and Abbreviations

AECO	Alberta natural gas reference location
AIF	Annual Information Form
AOSP	Athabasca Oil Sands Project
API	specific gravity measured in degrees on the American Petroleum Institute scale
ARO	asset retirement obligations
bbl	barrel
bbl/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Bitumen	a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons that are too heavy or thick to flow at reservoir conditions, and recoverable at economic rates using thermal in situ recovery methods
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
Brent	Dated Brent
C$	Canadian dollars
CAGR	compound annual growth rate
CAPEX	capital expenditures
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
Crude oil	includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil
CSS	Cyclic Steam Stimulation
EOR	Enhanced Oil Recovery
E&P	Exploration and Production
FASB	Financial Accounting Standards Board
FPSO	Floating Production, Storage and Offloading Vessel
GHG	greenhouse gas
GJ	gigajoules
GJ/d	gigajoules per day
Horizon	Horizon Oil Sands
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
Mbbl	thousand barrels
Mbbl/d	thousand barrels per day
MBOE	thousand barrels of oil equivalent
MBOE/d	thousand barrels of oil equivalent per day
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
Mcf/d	thousand cubic feet per day
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OPEC	Organization of the Petroleum Exporting Countries
PRT	Petroleum Revenue Tax
SAGD	Steam-Assisted Gravity Drainage
SCO	synthetic crude oil
SEC	United States Securities and Exchange Commission
Tcf	trillion cubic feet
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US GAAP	generally accepted accounting principles in the United States
US$	United States dollars
WCS	Western Canadian Select
WCS Heavy Differential	WCS Heavy Differential from WTI
WTI	West Texas Intermediate reference location at Cushing, Oklahoma

Advisory

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including, without limitation, those in relation to the Company's assets at Horizon, AOSP, Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the Jackfish Thermal Oil Sands Project, the timing and future operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, natural gas liquids ("NGLs") or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market, development and deployment of technology and technological innovations, the assumption of operations at processing facilities, and the "Outlook" section of this MD&A, particularly in reference to the 2020 guidance provided with respect to budgeted capital expenditures, also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and NGLs reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the earlier of the the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of demand and supply effects resulting from the COVID-19 virus pandemic and the actions of OPEC and non-OPEC countries) which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil, natural gas and NGL prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities (including production curtailments mandated by the Government of Alberta); government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company’s operations have been, and in the future may be, affected by political developments and by national, federal, provincial, state and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company’s assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company’s course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this MD&A could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by applicable law, the Company assumes no obligation to update forward-looking statements in this MD&A, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company's estimates or opinions change.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings from operations; adjusted funds flow (previously referred to as funds flow from operations) and net capital expenditures. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, cash flows from operating activities, and cash flows used in investing activities as determined in accordance with IFRS, as an indication of the Company’s performance. The non-GAAP measure adjusted net earnings from operations is reconciled to net earnings, as determined in accordance with IFRS, in the "Financial and Operational Highlights" section of this MD&A. Additionally, the non-GAAP measure adjusted funds flow is reconciled to cash flows from operating activities, as determined in accordance with IFRS, in the "Financial and Operational Highlights" section of this MD&A. The non-GAAP measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the "Net Capital Expenditures" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

SPECIAL NOTE REGARDING CURRENCY, FINANCIAL INFORMATION, PRODUCTION AND RESERVES

This MD&A should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2019. It should also be read in conjunction with the Company's MD&A for the three months and year ended December 31, 2019, which is incorporated herein by reference. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company’s consolidated financial statements and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). Changes in the Company's accounting policies in accordance with IFRS, including the adoption of IFRS 16 "Leases" on January 1, 2019, are discussed in the "Changes in Accounting Policies" section of this MD&A. In accordance with the new IFRS 16 "Leases" standard, comparative balances in 2018 reported in this MD&A have not been restated.

Production volumes, per unit statistics and reserves data are presented throughout this MD&A on a "before royalties" or "company gross" basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO. Production on an "after royalties" or "company net" basis is also presented in this MD&A for information purposes only.

The following discussion and analysis refers primarily to the Company’s 2019 financial results compared to 2018 and 2017, unless otherwise indicated. In addition, this MD&A details the Company's targeted capital program for 2020. Additional information relating to the Company, including its quarterly MD&A for the three months and year ended December 31, 2019, its Annual Information Form for the year ended December 31, 2019, and its audited consolidated financial statements for the year ended December 31, 2019, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Detailed guidance on production levels, capital expenditures and production expenses can be found on the Company's website at www.cnrl.com. Information on the Company’s website, including such guidance, does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated March 18, 2020.

Objectives and Strategy

The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value (1) on a per common share basis through the economic and sustainable development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves. The Company strives to meet these objectives in a sustainable and responsible way, maintaining a commitment to environmental stewardship and safety excellence.

The Company strives to meet these objectives by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a balanced approach to growth and investments and focuses on creating long-term shareholder value. The Company allocates its capital by maintaining:

- Balance among its products, namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil (2), bitumen (thermal oil), SCO and natural gas;
- A large, balanced, diversified, high quality, long life low decline asset base;
- Balance among acquisitions, exploitation and exploration;
- Balance between sources and terms of debt financing and a strong financial position; and
- Commitment to environmental stewardship throughout the decision-making process.

(1) Discounted value of crude oil and natural gas reserves plus value of unproved land, less net debt.

(2) Pelican Lake heavy crude oil is 12–17° API oil, which receives medium quality crude netbacks due to lower production expense and lower royalty rates.

The Company's three-phase crude oil marketing strategy includes:

- Blending various crude oil streams with diluents to create more attractive feedstock;
- Supporting and participating in pipeline expansions and/or new additions; and
- Supporting and participating in projects that will increase the downstream conversion capacity for heavy crude oil and bitumen (thermal oil).

Operational discipline, safe, effective and efficient operations, and cost control are fundamental to the Company and embraces the key piece of the Company's mission statement: "doing it right". By consistently managing costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Effective and efficient operations and cost control are attained by developing area knowledge, and by maintaining high working interests and operator status in its properties.

The Company is committed to maintaining a strong balance sheet and flexible capital structure. The Company believes it has built the necessary financial capacity to complete its growth projects. Additionally, the Company periodically utilizes its risk management hedging program to reduce the risk of volatility in commodity prices and foreign exchange rates and to support the Company's cash flow for its capital expenditure programs.

Strategic accretive acquisitions are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt and equity financing to selectively acquire properties generating future cash flows in its core areas. The Company's financial discipline, commitment to a strong balance sheet, and capacity to internally generate cash flows provides the means to responsibly and sustainably grow in the long term.

Financial and Operational Highlights

($ millions, except per common share amounts)			2019		2018		2017
Product sales [1]		$	**24,394**	$	22,282	$	18,360
Crude oil and NGLs		$	**22,950**	$	20,668	$	16,522
Natural gas		$	**1,419**	$	1,614	$	1,838
Net earnings		$	**5,416**	$	2,591	$	2,397
Per common share	– basic	$	**4.55**	$	2.13	$	2.04
	– diluted	$	**4.54**	$	2.12	$	2.03
Adjusted net earnings from operations [2]		$	**3,795**	$	3,263	$	1,403
Per common share	– basic	$	**3.19**	$	2.68	$	1.19
	– diluted	$	**3.18**	$	2.67	$	1.19
Cash flows from operating activities		$	**8,829**	$	10,121	$	7,262
Adjusted funds flow [3]		$	**10,267**	$	9,088	$	7,347
Per common share	– basic	$	**8.62**	$	7.46	$	6.25
	– diluted	$	**8.61**	$	7.43	$	6.21
Dividends declared per common share [4]		$	**1.50**	$	1.34	$	1.10
Total assets		$	**78,121**	$	71,559	$	73,867
Total long-term liabilities		$	**36,493**	$	34,823	$	35,953
Cash flows used in investing activities		$	**7,255**	$	4,814	$	13,102
Net capital expenditures [5]		$	**7,121**	$	4,731	$	17,129
Average sales price [6]							
Crude oil and NGLs - Exploration and Production ($/bbl)		$	**55.08**	$	46.92	$	48.57
Natural gas - Exploration and Production ($/Mcf)		$	**2.34**	$	2.61	$	2.76
Oil Sands Mining and Upgrading ($/bbl)		$	**70.18**	$	68.61	$	63.98
Daily production, before royalties (BOE/d)			**1,098,957**		1,078,813		962,264
Crude oil and NGLs (bbl/d)			**850,393**		820,778		685,236
Natural gas (MMcf/d)			**1,491**		1,548		1,662

(1) Further details related to product sales, including 'Other' income for 2019 are disclosed in note 22 to the Company's audited consolidated financial statements.

(2) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings as presented in the Company's consolidated Statements of Earnings, adjusted for the after-tax effects of certain items of a non-operational nature. The Company considers adjusted net earnings from operations a key measure in evaluating its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. The reconciliation "Adjusted Net Earnings from Operations, as Reconciled to Net Earnings" is presented in this MD&A. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(3) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls. The Company considers adjusted funds flow a key measure in evaluating its performance as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" is presented in this MD&A. Adjusted funds flow may not be comparable to similar measures presented by other companies.

(4) On March 4, 2020, the Board of Directors approved an increase in the quarterly dividend to $0.425 per common share, beginning with the dividend payable on April 1, 2020. On March 6, 2019, the Board of Directors approved an increase in the quarterly dividend to $0.375 per common share, beginning with the dividend payable on April 1, 2019. On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share, beginning with the dividend payable on April 1, 2018. On March 1, 2017, the Board of Directors approved an increase in the quarterly dividend to $0.275 per common share, beginning with the dividend payable on April 1, 2017.

(5) Net capital expenditures is a non-GAAP measure that represents cash flows used in investing activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, investment in other long-term assets, share consideration in business combinations and abandonment expenditures. The Company considers net capital expenditures a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. The reconciliation "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" is presented in the "Net Capital Expenditures" section of this MD&A. Net capital expenditures may not be comparable to similar measures presented by other companies.

(6) Net of blending and feedstock costs and excluding risk management activities.

ADJUSTED NET EARNINGS FROM OPERATIONS, AS RECONCILED TO NET EARNINGS

($ millions)		2019		2018		2017
Net earnings, as reported	$	**5,416**	$	2,591	$	2,397
Share-based compensation, net of tax (1)		**210**		(146)		134
Unrealized risk management loss (gain), net of tax (2)		**14**		(36)		33
Unrealized foreign exchange (gain) loss, net of tax (3)		**(548)**		706		(821)
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)		**—**		146		—
Loss (gain) from investments, net of tax (5) (6)		**321**		374		(11)
Gain on acquisition, disposition and revaluation of properties, net of tax (7)		**—**		(372)		(339)
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (8)		**(1,618)**		—		10
Adjusted net earnings from operations	$	**3,795**	$	3,263	$	1,403

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("PSU") plans. The Company's employee stock option plan provides for a cash payment option. The PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met. Accordingly, the fair value of the compensation under these plans is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings or are charged to (recovered from) the Oil Sands Mining and Upgrading segment.

(2) Derivative financial instruments are recorded at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than those amounts reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil, natural gas and foreign exchange.

(3) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, partially offset by the impact of cross currency swaps, and are recognized in net earnings.

(4) During 2018, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

(5) The Company's investment in the 50% owned North West Redwater Partnership ("Redwater Partnership") is accounted for using the equity method of accounting. Included in the non-cash loss (gain) from investments is the Company's pro rata share of the Redwater Partnership's equity loss (gain) recognized.

(6) The Company's investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("Inter Pipeline") have been accounted for at fair value through profit and loss and are measured each period with changes in fair value recognized in net earnings.

(7) During 2018, the Company recorded a pre-tax gain of $16 million ($12 million after-tax) on the disposition of a 30% interest in the exploration right in South Africa. Additionally, the Gabonese Republic approved cessation of production from the Company's Olowi field and associated asset retirement obligations, as well as the terms of termination of the Olowi Production Sharing Contract and the surrender of the permit area back to the Gabonese Republic, resulting in a pre-tax gain on disposition of property of $20 million ($14 million after-tax). The Company also recorded a pre-tax gain of $277 million ($263 million after-tax) related to acquisitions in the North America Exploration and Production segment. Additionally, the Company recorded a pre-tax gain of $120 million ($72 million after-tax) on the acquisition of the remaining interest at Ninian in the North Sea and a pre-tax gain of $19 million ($11 million after-tax) relating to the revaluation of the Company's previously held interest at Ninian. During 2017, the Company recorded a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system. Additionally, the Company recorded a pre and after-tax gain of $230 million on the acquisition of a direct and indirect 70% interest in AOSP and other assets from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), and a pre-tax gain of $35 million ($26 million after-tax) on the disposition of certain exploration and evaluation assets in the North America segment.

(8) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to the underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. During 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by $1,618 million. During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $10 million.

ADJUSTED FUNDS FLOW, AS RECONCILED TO CASH FLOWS FROM OPERATING ACTIVITIES (1)

($ millions)		2019		2018		2017
Cash flows from operating activities	$	**8,829**	$	10,121	$	7,262
Net change in non-cash working capital		**1,033**		(1,346)		(299)
Abandonment expenditures (2)		**296**		290		274
Other (3)		**109**		23		110
Adjusted funds flow	$	**10,267**	$	9,088	$	7,347

(1) Adjusted funds flow was previously referred to as funds flow from operations.

(2) The Company includes abandonment expenditures in "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" in the "Net Capital Expenditures" section of this MD&A.

(3) Movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

CONSOLIDATED NET EARNINGS AND ADJUSTED NET EARNINGS

For 2019, the Company reported net earnings of $5,416 million compared with $2,591 million for 2018 (2017 – $2,397 million). Net earnings for 2019 included net after-tax income of $1,621 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of realized foreign exchange losses on repayments of long-term debt, the loss from investments, gain on acquisition, disposition and revaluation of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities (2018 – $672 million after-tax income; 2017 – $994 million after-tax income). Excluding these items, adjusted net earnings from operations for 2019 were $3,795 million compared with $3,263 million for 2018 (2017 – $1,403 million).

The increase in net earnings and adjusted net earnings from operations for 2019 from 2018 was primarily due to:

- higher crude oil and NGLs sales volumes and netbacks in the Exploration and Production segments; and
- higher realized foreign exchange gains;

partially offset by:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower natural gas netbacks in the Exploration and Production segments; and
- higher realized risk management losses.

Net earnings for 2019 as compared to net earnings for 2018 also reflected the Government of Alberta enacted decrease in the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. This resulted in a decrease in the Company's deferred corporate income tax liability of $1,618 million. See the "Income Taxes" section of this MD&A.

The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates also contributed to the movements in net earnings for 2019 from 2018. For 2019, the adoption of IFRS 16 did not have a significant overall impact on net earnings or adjusted net earnings from operations. These items are discussed in detail in the relevant sections of this MD&A.

Subsequent to December 31, 2019, crude oil benchmark prices decreased substantially due to a drop in global crude oil demand triggered by the impact of the COVID-19 virus on the global economy. In March 2020, crude oil prices decreased further due to a breakdown in negotiations between OPEC and non-OPEC partners regarding proposed production cuts. The volatility in the crude oil pricing environment could impact the Company's earnings and cash flows.

CASH FLOWS FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW

Cash flows from operating activities for 2019 decreased to $8,829 million from $10,121 million for 2018 (2017 – $7,262 million). The decrease in cash flows from operating activities for 2019 from 2018 was primarily due to the impact of changes in non-cash working capital, primarily due to an increase in accounts receivable from 2018. Cash flows from operating activities was further impacted by factors previously noted relating to the fluctuations in net earnings and adjusted net earnings from operations (except for the effect of depletion, depreciation and amortization).

Adjusted funds flow for 2019 increased to $10,267 million ($8.62 per common share) from $9,088 million for 2018 ($7.46 per common share) (2017 – $7,347 million; $6.25 per common share). The increase in adjusted funds flow for 2019 from 2018 was primarily due to the factors previously noted relating to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

Cash flows from operating activities and adjusted funds flow for 2019 reflected an increase of $237 million related to the adoption of IFRS 16 on January 1, 2019 as the principal portions of lease payments previously classified as cash flows from operating activities are now reported as cash flows used in financing activities. The adoption of IFRS 16 is discussed in the "Changes in Accounting Policies" section of this MD&A.

PRODUCT PRICING

In the Company's Exploration and Production activities, the 2019 average sales price per barrel of crude oil and NGLs increased 17% to average $55.08 per bbl from $46.92 per bbl in 2018 (2017 – $48.57 per bbl), and the 2019 average natural gas price decreased 10% to average $2.34 per Mcf from $2.61 per Mcf in 2018 (2017 – $2.76 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2019 average SCO sales price of $70.18 per bbl compared with $68.61 per bbl in 2018 (2017 – $63.98 per bbl). Crude oil and NGLs and natural gas pricing are discussed in detail in the "Business Environment" section of this MD&A.

PRODUCTION VOLUMES

Total production of crude oil and NGLs before royalties for 2019 increased 4% to average 850,393 bbl/d from 820,778 bbl/d in 2018 (2017 – 685,236 bbl/d). The increase in crude oil and NGLs production from 2018 primarily reflected production from the acquisition of thermal and heavy oil assets from Devon Canada Corporation ("Devon"), offsetting the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. The Company continues to optimize its production volumes across the asset base during curtailment.

Total natural gas production before royalties for 2019 decreased 4% to average 1,491 MMcf/d from 1,548 MMcf/d in 2018 (2017 – 1,662 MMcf/d). The decrease in natural gas production from 2018 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities due to low natural gas prices.

Total production volumes before royalties for 2019 of 1,098,957 BOE/d was comparable with 1,078,813 BOE/d in 2018 (2017 – 962,264 BOE/d). Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

SUMMARY OF QUARTERLY FINANCIAL RESULTS

The following is a summary of the Company's quarterly financial results for the eight most recently completed quarters:

($ millions, except per common share amounts)

2019	**Total**	**Dec 31**	**Sep 30**	**Jun 30**	**Mar 31**
Product sales [1]	**$ 24,394**	**$ 6,335**	**$ 6,587**	**$ 5,931**	**$ 5,541**
Crude oil and NGLs	**$ 22,950**	**$ 5,947**	**$ 6,324**	**$ 5,597**	**$ 5,082**
Natural gas	**$ 1,419**	**$ 382**	**$ 257**	**$ 324**	**$ 456**
Net earnings (loss)	**$ 5,416**	**$ 597**	**$ 1,027**	**$ 2,831**	**$ 961**
Net earnings (loss) per common share					
– basic	**$ 4.55**	**$ 0.50**	**$ 0.87**	**$ 2.37**	**$ 0.80**
– diluted	**$ 4.54**	**$ 0.50**	**$ 0.87**	**$ 2.36**	**$ 0.80**

($ millions, except per common share amounts)

2018	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales	$ 22,282	$ 3,831	$ 6,327	$ 6,389	$ 5,735
Crude oil and NGLs	$ 20,668	$ 3,327	$ 5,967	$ 6,071	$ 5,303
Natural gas	$ 1,614	$ 504	$ 360	$ 318	$ 432
Net earnings (loss)	$ 2,591	$ (776)	$ 1,802	$ 982	$ 583
Net earnings (loss) per common share					
– basic	$ 2.13	$ (0.64)	$ 1.48	$ 0.80	$ 0.48
– diluted	$ 2.12	$ (0.64)	$ 1.47	$ 0.80	$ 0.47

(1) Further details related to product sales, including 'Other' income for 2019 are disclosed in note 22 to the Company's audited consolidated financial statements.

Volatility in the quarterly net earnings (loss) over the eight most recently completed quarters was primarily due to:

- **Crude oil pricing** – Fluctuating global supply/demand including crude oil production levels from OPEC and its impact on world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the WCS Heavy Differential from the WTI including the impact of a shortage of takeaway capacity out of the Western Canadian Sedimentary Basin (the "Basin") and the impact of the differential between WTI and Brent benchmark pricing in the North Sea and Offshore Africa and the impact of production curtailments mandated by the Government of Alberta that came into effect on January 1, 2019.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, third-party pipeline maintenance and outages and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, production from Kirby South and Kirby North, the results from the Pelican Lake water and polymer flood projects, fluctuations in the Company's drilling program in North America and the International segments, the impact and timing of acquisitions, including the acquisition of assets from Devon, production from Horizon Phase 3 as well as the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, voluntarily curtailed production in late 2018 due to low commodity prices in North America and production curtailments mandated by the Government of Alberta that came into effect January 1, 2019. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.

- **Natural gas sales volumes** – Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, natural decline rates, fluctuating capacity at the Pine River processing facility, shut-in production due to third party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production volumes, the impact of seasonal costs, the impact of increased carbon tax and energy costs, cost optimizations across all segments, the impact and timing of acquisitions, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, maintenance activities in the International segments and the impact of the adoption of IFRS 16 on January 1, 2019.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment and the impact of the adoption of IFRS 16 on January 1, 2019.
- **Share-based compensation** – Fluctuations due to the measurement of fair market value of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Interest expense** – Fluctuations due to the adoption of IFRS 16 on January 1, 2019, fluctuating long-term debt levels, and the impact of movements in benchmark interest rates on outstanding floating rate long-term debt.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company receives for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses were also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Gains on acquisition, disposition and revaluation of properties and gains/losses on investments** – Fluctuations due to the recognition of the acquisition, disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity loss on the Company's interest in the Redwater Partnership.
- **Income tax expense** – Fluctuations in income tax expense due to statutory tax rate and other legislative changes substantively enacted in the various periods.

Business Environment

(Yearly average)		2019		2018		2017
WTI benchmark price (US$/bbl)	**$**	**57.04**	$	64.78	$	50.93
Dated Brent benchmark price (US$/bbl)	**$**	**64.04**	$	71.12	$	54.38
WCS Heavy Differential from WTI (US$/bbl)	**$**	**12.79**	$	26.29	$	11.97
SCO price (US$/bbl)	**$**	**56.35**	$	58.62	$	52.20
Condensate benchmark price (US$/bbl)	**$**	**52.84**	$	60.98	$	51.65
Condensate Differential from WTI (US$/bbl)	**$**	**4.20**	$	3.80	$	(0.72)
NYMEX benchmark price (US$/MMBtu)	**$**	**2.63**	$	3.08	$	3.11
AECO benchmark price (C$/GJ)	**$**	**1.54**	$	1.45	$	2.30
US/Canadian dollar average exchange rate (US$)	**$**	**0.7536**	$	0.7717	$	0.7701
US/Canadian dollar year end exchange rate (US$)	**$**	**0.7713**	$	0.7328	$	0.7988

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are highly sensitive to fluctuations in foreign exchange rates. Product revenue continued to be impacted by the volatility of the Canadian dollar as the Canadian dollar sales price the Company received for its crude oil and natural gas sales is based on US dollar denominated benchmarks.

Effective January 1, 2019, the Government of Alberta implemented a mandatory curtailment program that has been successful in mitigating the discount in crude oil pricing received in Alberta for both light crude oil and heavy crude oil. The timing of program cessation remains uncertain. The Company continues to execute operational flexibility to maximize production volumes through its curtailment optimization strategy, and has significant additional capacity available to further increase production volumes should curtailment restrictions ease.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$57.04 per bbl for 2019, a decrease of 12% from US$64.78 per bbl for 2018 (2017 – US$50.93 per bbl).

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$64.04 per bbl for 2019, a decrease of 10% from US$71.12 per bbl for 2018 (2017 – US$54.38 per bbl).

WTI and Brent pricing for 2019 decreased from 2018 primarily due to increases in non-OPEC crude oil supply. In addition, global crude oil pricing has been impacted by ongoing trade disputes between the US and China.

The WCS Heavy Differential averaged US$12.79 per bbl for 2019, a decrease of 51% from US$26.29 per bbl for 2018 (2017 – US$11.97 per bbl). The narrowing of the WCS Heavy Differential reflected the impact of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019.

The SCO price averaged US$56.35 per bbl for 2019, a decrease of 4% from US$58.62 per bbl for 2018 (2017 – US$52.20 per bbl). The decrease in SCO pricing for 2019 from 2018 primarily reflected decreases in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.63 per MMBtu for 2019, a decrease of 15% from US$3.08 per MMBtu for 2018 (2017 – US$3.11 per MMBtu). The decrease in NYMEX natural gas prices for 2019 from 2018 primarily reflected increased production levels in North America and the impact of seasonal weather conditions.

AECO natural gas prices averaged $1.54 per GJ for 2019, an increase of 6% from $1.45 per GJ for 2018 (2017 – $2.30 per GJ). The increase in AECO natural gas prices for 2019 from 2018 primarily reflected additional egress capability and the impact of the TC Energy Temporary Service Protocol.

Analysis of Changes in Product Sales

($ millions)	2017	Changes due to Volumes	Changes due to Prices	Changes due to Other	2018	**Changes due to Volumes**	**Changes due to Prices**	**Changes due to Other**	**2019**
North America									
Crude oil and NGLs	$ 7,655	$ (188)	$ (224)	$ 11	$ 7,254	**$ 1,055**	**$ 1,375**	**$ (5)**	**$ 9,679**
Natural gas	1,506	(105)	(136)	(9)	1,256	**(40)**	**(76)**	**10**	**1,150**
Other	—	—	—	—	—	**—**	**—**	**6**	**6**
	9,161	(293)	(360)	2	8,510	**1,015**	**1,299**	**11**	**10,835**
North Sea									
Crude oil and NGLs	666	(69)	155	1	753	**114**	**(7)**	**—**	**860**
Natural gas	118	(23)	45	—	140	**(34)**	**(49)**	**—**	**57**
Other	—	—	—	—	—	**—**	**—**	**5**	**5**
	784	(92)	200	1	893	**80**	**(56)**	**5**	**922**
Offshore Africa									
Crude oil and NGLs	579	(102)	164	(13)	628	**72**	**(56)**	**(12)**	**632**
Natural gas	53	10	7	—	70	**(5)**	**1**	**1**	**67**
Other	—	—	—	—	—	**—**	**—**	**8**	**8**
	632	(92)	171	(13)	698	**67**	**(55)**	**(3)**	**707**
Total Exploration and Production									
Crude oil and NGLs	8,900	(359)	95	(1)	8,635	**1,241**	**1,312**	**(17)**	**11,171**
Natural gas	1,677	(118)	(84)	(9)	1,466	**(79)**	**(124)**	**11**	**1,274**
Other	—	—	—	—	—	**—**	**—**	**19**	**19**
	10,577	(477)	11	(10)	10,101	**1,162**	**1,188**	**13**	**12,464**
Oil Sands Mining and Upgrading									
Crude oil and NGLs	7,072	3,696	722	31	11,521	**(710)**	**560**	**(31)**	**11,340**
Other	—	—	—	—	—	**—**	**—**	**6**	**6**
	7,072	3,696	722	31	11,521	**(710)**	**560**	**(25)**	**11,346**
Midstream and Refining	102	—	—	—	102	**—**	**—**	**(14)**	**88**
Intersegment eliminations and other (1)	609	—	—	(51)	558	**—**	**—**	**(62)**	**496**
Total	$18,360	$ 3,219	$ 733	$ (30)	$ 22,282	**$ 452**	**$ 1,748**	**$ (88)**	**$ 24,394**

(1) Eliminates internal transportation and electricity charges and includes production, processing and other purchasing and selling activities that are not included in the above segments.

Product sales increased 9% to $24,394 million for 2019 from $22,282 million for 2018 (2017 – $18,360 million). The increase was primarily due to higher realized crude oil and NGLs pricing in North America, together with increased crude oil and NGLs sales volumes in the North America Exploration and Production segment following the acquisition of thermal and heavy oil assets from Devon, offsetting the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. Crude oil and NGLs and natural gas pricing are discussed in detail in the "Business Environment" section of this MD&A. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

For 2019, 7% of the Company's crude oil and NGLs and natural gas product sales were generated outside of North America (2018 – 7%; 2017 – 8%). North Sea accounted for 4% of crude oil and NGLs and natural gas product sales for 2019 (2018 – 4%; 2017 – 4%), and Offshore Africa accounted for 3% of crude oil and NGLs and natural gas product sales for 2019 (2018 – 3%; 2017 – 4%).

Daily Production, Before Royalties

	2019	2018	2017
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**405,970**	350,961	359,449
North America – Oil Sands Mining and Upgrading [1]	**395,133**	426,190	282,026
North Sea	**27,919**	23,965	23,426
Offshore Africa	**21,371**	19,662	20,335
	850,393	820,778	685,236
Natural gas (MMcf/d)			
North America	**1,443**	1,490	1,601
North Sea	**24**	32	39
Offshore Africa	**24**	26	22
	1,491	1,548	1,662
Total barrels of oil equivalent (BOE/d)	**1,098,957**	1,078,813	962,264
Product mix			
Light and medium crude oil and NGLs	**13%**	13%	14%
Pelican Lake heavy crude oil	**5%**	6%	6%
Primary heavy crude oil	**8%**	8%	10%
Bitumen (thermal oil)	**15%**	10%	12%
Synthetic crude oil [1]	**36%**	39%	29%
Natural gas	**23%**	24%	29%
Percentage of gross revenue [1] [2]			
(excluding Midstream and Refining revenue)			
Crude oil and NGLs	**94%**	93%	90%
Natural gas	**6%**	7%	10%

(1) SCO production before royalties excludes SCO consumed internally as diesel.
(2) Net of blending costs and excluding risk management activities.

Daily Production, Net of Royalties

	2019	2018	2017
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**356,794**	303,956	312,297
North America – Oil Sands Mining and Upgrading	**375,048**	405,731	274,437
North Sea	**27,866**	23,902	23,382
Offshore Africa	**20,078**	18,450	19,124
	779,786	752,039	629,240
Natural gas (MMcf/d)			
North America	**1,400**	1,432	1,528
North Sea	**24**	32	39
Offshore Africa	**22**	23	20
	1,446	1,487	1,587
Total barrels of oil equivalent (BOE/d)	**1,020,749**	999,857	893,702

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), SCO and natural gas.

Total 2019 production before royalties averaged 1,098,957 BOE/d, comparable with 1,078,813 BOE/d in 2018 (2017 – 962,264 BOE/d).

Total production of crude oil and NGLs before royalties for 2019 increased 4% to 850,393 bbl/d from 820,778 bbl/d for 2018 (2017 – 685,236 bbl/d). The increase in crude oil and NGLs production from 2018 primarily reflected production from the acquisition of thermal and heavy oil assets from Devon, offsetting the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. The Company continues to optimize its production volumes across the asset base during curtailment. Crude oil and NGLs production before royalties for 2019 was within the Company's previously issued guidance of 839,000 to 888,000 bbl/d.

Natural gas production before royalties accounted for 23% of the Company's total production in 2019 on a BOE basis. Natural gas production for 2019 decreased 4% to 1,491 MMcf/d from 1,548 MMcf/d for 2018 (2017 – 1,662 MMcf/d). The decrease in natural gas production from 2018 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities due to low natural gas prices. Natural gas production for 2019 was within the Company's previously issued guidance of 1,485 to 1,545 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for 2019 increased 16% to average 405,970 bbl/d from 350,961 bbl/d for 2018 (2017 – 359,449 bbl/d). The increase in production from 2018 primarily reflected the acquisition of thermal and heavy oil assets from Devon that closed in 2019 and increased production of thermal oil due to additional production from Kirby North and pad additions at Primrose, reflecting optimization of curtailment volumes across the Company's asset base.

Thermal oil production before royalties for 2019 averaged 167,942 bbl/d compared with 107,839 bbl/d for 2018 (2017 – 120,140 bbl/d). Production volumes in 2019 primarily reflected volumes from the acquisition of assets from Devon, together with new production from Kirby North and pad additions at Primrose, reflecting optimization of curtailment volumes across the Company's asset base.

Pelican Lake heavy crude oil production before royalties averaged production of 58,855 bbl/d in 2019 compared with 63,082 bbl/d in 2018 (2017 – 51,743 bbl/d).

Natural gas production before royalties for 2019 decreased 3% to average 1,443 MMcf/d from 1,490 MMcf/d for 2018 (2017 – 1,601 MMcf/d). The decrease in natural gas production from 2018 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities due to low natural gas prices.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for 2019 decreased 7% to 395,133 bbl/d from 426,190 bbl/d for 2018 (2017 – 282,026 bbl/d). The decrease in SCO production from 2018 primarily reflected the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. Production in 2019 was impacted by the Government of Alberta mandated production curtailments that came into effect on January 1, 2019.

North Sea

North Sea crude oil production before royalties for 2019 increased 16% to 27,919 bbl/d from 23,965 bbl/d for 2018 (2017 – 23,426 bbl/d). The increase in production from 2018 primarily reflected volumes from new wells.

Offshore Africa

Offshore Africa crude oil production before royalties for 2019 increased 9% to 21,371 bbl/d from 19,662 bbl/d for 2018 (2017 – 20,335 bbl/d). The increase in production from 2018 primarily reflected volumes from new wells drilled at Baobab, partially offset by the cessation of production at the Olowi field, Gabon in December 2018 and natural field declines.

Corporate Production Guidance for 2020

The Company targets production levels in 2020 to average between 910,000 bbl/d and 970,000 bbl/d of crude oil and NGLs and between 1,360 MMcf/d and 1,420 MMcf/d of natural gas.

INTERNATIONAL CRUDE OIL INVENTORY VOLUMES

The Company recognizes revenue on its crude oil production when control of the product passes to the customer and delivery has taken place. Revenue has not been recognized in the International business segments on crude oil volumes held in various storage facilities or FPSOs, as follows:

(bbl)	**2019**	2018	2017
North Sea	**344,726**	71,832	—
Offshore Africa	**519,504**	404,475	121,936
	864,230	476,307	121,936

Exploration and Production

OPERATING HIGHLIGHTS

		2019		2018		2017
Crude oil and NGLs ($/bbl) [1]						
Sales price [2]	$	**55.08**	$	46.92	$	48.57
Transportation		**3.48**		3.08		2.80
Realized sales price, net of transportation		**51.60**		43.84		45.77
Royalties		**6.08**		5.08		5.24
Production expense		**13.81**		15.69		14.89
Netback	$	**31.71**	$	23.07	$	25.64
Natural gas ($/Mcf) [1]						
Sales price [2]	$	**2.34**	$	2.61	$	2.76
Transportation		**0.42**		0.47		0.39
Realized sales price, net of transportation		**1.92**		2.14		2.37
Royalties		**0.08**		0.08		0.11
Production expense		**1.22**		1.36		1.27
Netback	$	**0.62**	$	0.70	$	0.99
Barrels of oil equivalent ($/BOE) [1]						
Sales price [2]	$	**40.50**	$	34.62	$	35.54
Transportation		**3.14**		2.96		2.66
Realized sales price, net of transportation		**37.36**		31.66		32.88
Royalties		**4.09**		3.27		3.40
Production expense		**11.49**		12.71		11.95
Netback	$	**21.78**	$	15.68	$	17.53

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

PRODUCT PRICES

		2019		2018		2017
Crude oil and NGLs ($/bbl) [1] [2]						
North America	$	**51.43**	$	41.82	$	45.85
North Sea	$	**86.76**	$	87.41	$	69.43
Offshore Africa	$	**83.68**	$	90.95	$	67.15
Company average	$	**55.08**	$	46.92	$	48.57
Natural gas ($/Mcf) [1] [2]						
North America	$	**2.18**	$	2.33	$	2.58
North Sea	$	**6.52**	$	12.08	$	8.24
Offshore Africa	$	**7.41**	$	7.34	$	6.57
Company average	$	**2.34**	$	2.61	$	2.76
Company average ($/BOE) [1] [2]	$	**40.50**	$	34.62	$	35.54

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

North America - Product Prices

North America realized crude oil prices increased 23% to average $51.43 per bbl for 2019 from $41.82 per bbl for 2018 (2017 – $45.85 per bbl), primarily due to the narrowing of the WCS Heavy Differential as a result of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019.

North America realized natural gas prices decreased 6% to average $2.18 per Mcf for 2019 from $2.33 per Mcf for 2018 (2017 – $2.58 per Mcf). The decrease primarily reflected increased production levels in North America and the impact of seasonal weather conditions.

The Company continues to focus on its crude oil marketing strategy including a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil and bitumen (thermal oil) conversion capacity. During 2019, the Company contributed approximately 174,700 bbl/d of heavy crude oil blends to the WCS stream.

The Company has 20 year transportation agreements to ship 94,000 bbl/d of crude oil on the proposed Trans Mountain Pipeline Expansion. The Canadian Energy Regulator (formerly The National Energy Board) has provided its recommendation that construction of the pipeline should proceed and the Federal cabinet approved the project on June 18, 2019. On February 4, 2020, an appeal from Indigenous groups to the Federal Court of Appeal was dismissed. Pipeline construction, which had commenced, was permitted to continue subject to the outcome of the appeal to the Supreme Court of Canada. Leave to appeal to the Supreme Court of Canada was refused on March 5, 2020.

The Company also has 20 year transportation agreements to ship 200,000 bbl/d of crude oil on the proposed TC Energy Keystone XL Pipeline. On August 23, 2019 the Nebraska Supreme Court ruled that the Nebraska Public Service Commission's route approval was valid. The proponent is awaiting the decision from the Montana Federal Court case filed by various environmental groups challenging the Presidential Permit granted in 2019. Pre-construction activities have commenced and the proponent expects the construction program to be approximately two years once construction has commenced.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

(Yearly average)		**2019**		2018		2017
Wellhead Price (1) (2)						
Light and medium crude oil and NGLs ($/bbl)	**$**	**49.54**	$	52.87	$	47.78
Pelican Lake heavy crude oil ($/bbl)	**$**	**57.82**	$	43.30	$	48.30
Primary heavy crude oil ($/bbl)	**$**	**55.38**	$	38.98	$	46.88
Bitumen (thermal oil) ($/bbl)	**$**	**48.27**	$	33.66	$	42.49
Natural gas ($/Mcf)	**$**	**2.18**	$	2.33	$	2.58

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

North Sea - Product Prices

North Sea realized crude oil prices of $86.76 per bbl for 2019 were comparable with $87.41 per bbl for 2018 (2017 – $69.43 per bbl). Realized crude oil prices per barrel in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting.

Offshore Africa - Product Prices

Offshore Africa realized crude oil prices decreased 8% to average $83.68 per bbl for 2019 from $90.95 per bbl for 2018 (2017 – $67.15 per bbl). Realized crude oil prices per barrel in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The decrease in realized crude oil prices in 2019 reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES

		2019		2018		2017
Crude oil and NGLs ($/bbl) (1)						
North America	**$**	**6.56**	$	5.36	$	5.69
North Sea	**$**	**0.16**	$	0.22	$	0.13
Offshore Africa	**$**	**4.74**	$	6.00	$	4.13
Company average	**$**	**6.08**	$	5.08	$	5.24
Natural gas ($/Mcf) (1)						
North America	**$**	**0.07**	$	0.07	$	0.11
Offshore Africa	**$**	**0.63**	$	1.00	$	0.76
Company average	**$**	**0.08**	$	0.08	$	0.11
Company average ($/BOE) (1)	**$**	**4.09**	$	3.27	$	3.40

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America - Royalties

Government royalties on a significant portion of North America crude oil and NGLs production fall under the oil sands royalty regime and are calculated on a project by project basis as a percentage of gross revenue less operating, capital and abandonment costs incurred ("net profit").

North America crude oil and natural gas royalty rates for 2019 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalty rates also reflected fluctuations in the WCS Heavy Differential and changes in the production mix between high and low royalty rate product types.

Crude oil and NGLs royalty rates averaged approximately 13% of product sales for 2019 compared with 14% of product sales for 2018 (2017 – 13%).

Natural gas royalty rates averaged approximately 3% of product sales for 2019 compared with 4% of product sales for 2018 (2017 – 5%).

Offshore Africa - Royalties

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital expenditures and production expenses, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 6% for 2019 compared with 7% of product sales for 2018 (2017 – 7%). Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

PRODUCTION EXPENSE

		2019		2018		2017
Crude oil and NGLs ($/bbl) (1)						
North America	**$**	**12.41**	$	13.48	$	12.71
North Sea	**$**	**36.39**	$	39.89	$	36.60
Offshore Africa	**$**	**11.21**	$	26.34	$	24.07
Company average	**$**	**13.81**	$	15.69	$	14.89
Natural gas ($/Mcf) (1)						
North America	**$**	**1.16**	$	1.25	$	1.19
North Sea (2)	**$**	**3.40**	$	5.29	$	3.37
Offshore Africa (2)	**$**	**2.60**	$	2.76	$	2.90
Company average	**$**	**1.22**	$	1.36	$	1.27
Company average ($/BOE) (1)	**$**	**11.49**	$	12.71	$	11.95

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) North Sea and Offshore Africa natural gas production expense for 2019 reflected a decrease of $23 million ($2.66 per Mcf) and $5 million ($0.55 per Mcf) respectively, related to the adoption of IFRS 16.

North America - Production Expense

North America crude oil and NGLs production expense for 2019 decreased 8% to $12.41 per bbl from $13.48 per bbl for 2018 (2017 – $12.71 per bbl). The decrease in crude oil and NGLs production expense for 2019 from 2018 primarily reflected the impact of operating cost synergies captured to date combined with added production from the acquisition of assets from Devon, Kirby North and pad additions at Primrose, offsetting the impact of higher fuel and energy costs. The Company continues to focus on cost control and achieving efficiencies across the entire asset base.

North America crude oil and NGLs production expense for 2019 also reflected a decrease of $22 million ($0.15 per bbl) related to the adoption of IFRS 16.

North America natural gas production expense for 2019 decreased 7% to $1.16 per Mcf from $1.25 per Mcf for 2018 (2017 – $1.19 per Mcf). The decrease in natural gas production expense for 2019 from 2018 primarily reflected the strength of the Company's strategy to own and control its infrastructure, continued focus on cost control, and achieving efficiencies across the entire asset base.

North America natural gas production expense for 2019 also reflected a decrease of $6 million ($0.01 per Mcf) related to the adoption of IFRS 16.

North Sea - Production Expense

North Sea crude oil production expense for 2019 decreased 9% to $36.39 per bbl from $39.89 per bbl for 2018 (2017 – $36.60 per bbl). The decrease in crude oil production expense for 2019 from 2018 primarily reflected increased production volumes, together with fluctuations in the Canadian dollar.

North Sea crude oil production expense for 2019 also reflected a decrease of $21 million ($2.10 per bbl) related to the adoption of IFRS 16.

Offshore Africa - Production Expense

Offshore Africa crude oil production expense was $11.21 per bbl for 2019 compared with $26.34 per bbl for 2018 (2017 – $24.07 per bbl). The decrease in crude oil production expense for 2019 from 2018 primarily reflected the cessation of production at the Olowi field, Gabon in December 2018. Crude oil production expense also reflected the timing of liftings from various fields that have different cost structures, fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar.

Offshore Africa crude oil production expense for 2019 also reflected a decrease of $20 million ($2.56 per bbl) related to the adoption of IFRS 16.

DEPLETION, DEPRECIATION AND AMORTIZATION

($ millions, except per BOE amounts)		**2019**		2018		2017
North America	**$**	**3,326**	$	3,132	$	3,243
North Sea		**308**		257		509
Offshore Africa		**242**		201		205
Expense	**$**	**3,876**	$	3,590	$	3,957
$/BOE (1)	**$**	**15.22**	$	15.12	$	15.82

(1) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, depreciation and amortization in 2019 of $15.22 per BOE was comparable with $15.12 per BOE for 2018 (2017 – $15.82 per BOE). Depletion, depreciation and amortization expense for 2019 reflected an increase of $168 million ($0.66 per BOE) related to the adoption of IFRS 16.

ASSET RETIREMENT OBLIGATION ACCRETION

($ millions, except per BOE amounts)		**2019**		2018		2017
North America	**$**	**95**	$	87	$	80
North Sea		**28**		29		27
Offshore Africa		**6**		9		9
Expense	**$**	**129**	$	125	$	116
$/BOE (1)	**$**	**0.51**	$	0.53	$	0.46

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Asset retirement obligation accretion expense for 2019 decreased 4% to $0.51 per BOE from $0.53 per BOE for 2018 (2017 – $0.46 per BOE). Fluctuations in asset retirement obligation accretion expense on a per BOE basis primarily reflect fluctuating sales volumes.

Oil Sands Mining and Upgrading

OPERATING HIGHLIGHTS

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the Horizon and AOSP sites. Production averaged 395,133 bbl/d during 2019, reflecting the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. Production levels during the year continued to be impacted by the Government of Alberta mandated production curtailments that came into effect January 1, 2019.

Through continuous focus on cost control and efficiencies, the Company has achieved a decrease of $124 million (4%) in adjusted production costs, excluding natural gas costs for 2019 of $3,032 million ($20.89 per bbl), from $3,156 million ($20.39 per bbl) for 2018.

PRODUCT PRICES, ROYALTIES AND TRANSPORTATION

($/bbl) (1)		**2019**		2018		2017
SCO realized sales price (2)	**$**	**70.18**	$	68.61	$	63.98
Bitumen value for royalty purposes (3)	**$**	**50.79**	$	40.02	$	41.05
Bitumen royalties (4)	**$**	**3.31**	$	3.09	$	1.64
Transportation	**$**	**1.29**	$	1.61	$	1.54

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.
(2) Net of blending and feedstock costs.
(3) Calculated as the annual average of the bitumen valuation methodology price.
(4) Calculated based on bitumen royalties expensed during the year; divided by the corresponding SCO sales volumes.

The realized SCO sales price averaged $70.18 per bbl for 2019, comparable with $68.61 per bbl for 2018 (2017 – $63.98 per bbl).

Transportation expense averaged $1.29 per bbl for 2019, compared with $1.61 per bbl for 2018 (2017 – $1.54 per bbl). Transportation expense for 2019 reflected a decrease of $78 million ($0.53 per bbl) related to the adoption of IFRS 16.

PRODUCTION COSTS

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 22 to the Company's audited consolidated financial statements.

($ millions)		**2019**		2018		2017
Production costs	**$**	**3,276**	$	3,367	$	2,600
Less: costs incurred during turnaround periods		**(119)**		(109)		(216)
Adjusted production costs	**$**	**3,157**	$	3,258	$	2,384

Adjusted production costs, excluding natural gas costs	**$**	**3,032**	$	3,156	$	2,239
Natural gas costs		**125**		102		145
Adjusted production costs	**$**	**3,157**	$	3,258	$	2,384

($/bbl) (1)		**2019**		2018		2017
Adjusted production costs, excluding natural gas costs	**$**	**20.89**	$	20.39	$	21.98
Natural gas costs		**0.86**		0.66		1.42
Adjusted production costs	**$**	**21.75**	$	21.05	$	23.40
Sales (bbl/d)		**397,735**		424,112		279,084

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

Production costs for 2019 were $22.56 per bbl compared with $21.75 per bbl in 2018 (2017 – $25.52 per bbl). Adjusted production costs for 2019 increased 3% to $21.75 per bbl from $21.05 per bbl for 2018 (2017 – $23.40 per bbl). The increase in adjusted production costs per barrel for 2019 from 2018 primarily reflected reduced production volumes due to the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with increased natural gas costs.

Production costs for 2019 also reflected a decrease of $29 million ($0.20 per bbl) related to the adoption of IFRS 16.

DEPLETION, DEPRECIATION AND AMORTIZATION

($ millions, except per bbl amounts)		2019		2018		2017
Depletion, depreciation and amortization	**$**	**1,656**	$	1,557	$	1,220
Less: depreciation incurred during turnaround periods		**(69)**		(56)		(213)
Adjusted depletion, depreciation and amortization	**$**	**1,587**	$	1,501	$	1,007
$/bbl (1)	**$**	**10.94**	$	9.70	$	9.89

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

Adjusted depletion, depreciation and amortization expense for 2019 increased 13% to $10.94 per bbl from $9.70 per bbl for 2018 (2017 – $9.89 per bbl). This increase primarily reflected fluctuations in sales volumes from different underlying operations, a proactive piping replacement at Horizon, and the adoption of IFRS 16. Depletion, depreciation and amortization expense for 2019 also reflected an increase of $92 million ($0.63 per bbl) related to the adoption of IFRS 16.

ASSET RETIREMENT OBLIGATION ACCRETION

($ millions, except per bbl amounts)		2019		2018		2017
Expense	**$**	**61**	$	61	$	48
$/bbl (1)	**$**	**0.42**	$	0.40	$	0.47

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Asset retirement obligation accretion expense for 2019 increased 5% to $0.42 per bbl from $0.40 per bbl for 2018 (2017 – $0.47 per bbl). Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

Midstream and Refining

($ millions)		2019		2018		2017
Revenue	**$**	**88**	$	102	$	102
Less:						
Production expense		**20**		21		16
Depreciation		**14**		14		9
Equity loss (gain) from Redwater Partnership		**287**		5		(31)
Gain on revaluation of properties		**—**		—		(114)
Segment earnings (loss) before taxes	**$**	**(233)**	$	62	$	222

The Company's Midstream assets consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose and the Company's 50% interest in the Redwater Partnership. Approximately 30% of the Company's heavy crude oil production was transported to international mainline liquid pipelines via the 100% owned and operated ECHO and Pelican Lake pipelines. The Midstream pipeline asset ownership allows the Company to control transportation costs, earn third party revenue, and manage the marketing of heavy crudes.

During 2017, the Company recorded a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system.

Redwater Partnership has entered into agreements to construct and operate a 50,000 bbl/d bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 bbl/d of bitumen feedstock for the Company and 37,500 bbl/d of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2018, Redwater Partnership commenced commissioning activities in the Project's light oil units while continuing work on the heavy oil units. In the first quarter of 2019, the light oil units transitioned from pre-commissioning and startup to operations and are processing synthetic crude oil into refined products. In December 2019, the light oil refinery completed activities relating to the planned maintenance shutdown. The Project continues to operate as a light oil refinery and will continue to process synthetic crude oil into refined products until the heavy oil units can reliably commence commercial processing of bitumen. Design modifications to the reactor burners in the gasifier unit are ongoing and have continued through the first quarter of 2020. As at December 31, 2019, the total estimate of capital costs incurred for the Project, net of margins from pre-commercial sales, was approximately $10 billion.

During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect the agreed debt to equity ratio of 80/20. As at December 31, 2019, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $213 million, for a Company total of $652 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, currently consisting of interest and fees, with principal repayments beginning in 2020. The Company is unconditionally obligated to pay this portion of the cost of service tolls over the 30-year tolling period. As at December 31, 2019, the Company had recognized $130 million in prepaid cost of service tolls (December 31, 2018 – $62 million).

Redwater Partnership has a secured $3,500 million syndicated credit facility, of which $2,000 million is revolving and matures in June 2021 and the remaining $1,500 million is fully drawn on a non-revolving basis. During 2019, Redwater Partnership extended the $1,500 million non-revolving facility, previously scheduled to mature in February 2020, to February 2021. As at December 31, 2019, Redwater Partnership had borrowings of $2,715 million under the secured syndicated credit facility.

The Company recognized an equity loss from Redwater Partnership of $287 million for 2019 (2018 – loss of $5 million), reducing the carrying value in Redwater Partnership to $nil. The unrecognized share of losses from Redwater Partnership for 2019 was $59 million. The equity loss for 2019 primarily reflected the impact of Redwater Partnership deferring cost of service toll revenue until it achieves commercial operations and is reliably processing toll payers' bitumen.

Corporate and Other

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)		**2019**		2018		2017
Expense	**$**	**344**	$	325	$	319
$/BOE (1)	**$**	**0.86**	$	0.83	$	0.91

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense for 2019 increased 4% to $0.86 per BOE from $0.83 per BOE for 2018 (2017 – $0.91 per BOE). Administration expense per BOE increased for 2019 from 2018 primarily due to higher personnel costs, including those associated with the acquisition of assets from Devon. Administration expense for 2019 also reflected a decrease of $23 million ($0.06 per BOE) related to the adoption of IFRS 16.

SHARE-BASED COMPENSATION

($ millions)		**2019**		2018		2017
Expense (recovery)	**$**	**223**	$	(146)	$	134

The Company's Stock Option Plan provides current employees with the right to receive common shares or a cash payment in exchange for stock options surrendered. The PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met.

The Company recorded a $223 million share-based compensation expense for 2019, primarily as a result of the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period, and changes in the Company's share price. Included within the share-based compensation expense for 2019 was $49 million related to PSUs granted to certain executive employees (2018 – $8 million; 2017 – $5 million). For 2019, the Company charged $5 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (2018 – $19 million recovered, 2017 – $14 million charged).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)		2019		2018		2017
Expense, gross	**$**	**889**	$	808	$	713
Less: capitalized interest		**53**		69		82
Expense, net	**$**	**836**	$	739	$	631
$/BOE [1]	**$**	**2.09**	$	1.88	$	1.79
Average effective interest rate		**4.0%**		3.9%		3.8%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest and other financing expense for 2019 increased from 2018 primarily due to interest expense on lease liabilities recognized due to the adoption of IFRS 16. Capitalized interest of $53 million for 2019 was related to Kirby North and residual project activities at Horizon.

Net interest and other financing expense for 2019 increased 11% to $2.09 per BOE from $1.88 per BOE for 2018 (2017 – $1.79 per BOE). The increase for 2019 from 2018 primarily reflected the adoption of IFRS 16, together with lower capitalized interest and higher levels of debt in 2019. Net interest and other financing expense for 2019 reflected an increase of $70 million ($0.18 per BOE) related to the adoption of IFRS 16.

The Company's average effective interest rate of 4.0% for 2019 was consistent with 2018.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These derivative financial instruments are not intended for trading or speculative purposes.

($ millions)		2019		2018		2017
Crude oil and NGLs financial instruments	**$**	**52**	$	(27)	$	(32)
Natural gas financial instruments		**(1)**		5		(7)
Foreign currency contracts		**13**		(77)		37
Realized loss (gain)	**$**	**64**	$	(99)	$	(2)
Crude oil and NGLs financial instruments	**$**	**(17)**	$	16	$	—
Natural gas financial instruments		**15**		(4)		(6)
Foreign currency contracts		**15**		(47)		43
Unrealized loss (gain)	**$**	**13**	$	(35)	$	37
Net loss (gain)	**$**	**77**	$	(134)	$	35

During 2019, net realized risk management losses were related to the settlement of crude oil and NGLs financial instruments and foreign currency contracts. The Company recorded a net unrealized loss of $13 million ($14 million after-tax) on its risk management activities for 2019 (2018 – $35 million unrealized gain, $36 million after-tax; 2017 – $37 million unrealized loss, $33 million after-tax).

Complete details related to outstanding derivative financial instruments at December 31, 2019 are disclosed in note 19 to the Company's audited consolidated financial statements.

FOREIGN EXCHANGE

($ millions)		2019		2018		2017
Net realized (gain) loss	**$**	**(22)**	$	121	$	34
Net unrealized (gain) loss		**(548)**		706		(821)
Net (gain) loss [1]	**$**	**(570)**	$	827	$	(787)

(1) Amounts are reported net of the hedging effect of cross currency swaps.

The net realized foreign exchange gain for 2019 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for 2019 was primarily related to the impact of the stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (2019 – unrealized loss of $71 million, 2018 – unrealized gain of $118 million, 2017 – unrealized loss of $280 million). The US/Canadian dollar exchange rate at December 31, 2019 was US$0.7713 (December 31, 2018 – US$0.7328, December 31, 2017 – US$0.7988).

INCOME TAXES

($ millions, except income tax rates)		2019		2018		2017
North America [1]	**$**	**354**	$	312	$	(145)
North Sea		**112**		28		57
Offshore Africa		**44**		54		45
PRT – North Sea		**(89)**		(29)		(132)
Other taxes		**13**		9		11
Current income tax expense (recovery)		**434**		374		(164)
Deferred corporate income tax (recovery) expense		**(895)**		540		586
Deferred PRT expense – North Sea		**1**		17		54
Deferred income tax (recovery) expense		**(894)**		557		640
		(460)		931		476
Income tax rate and other legislative changes		**1,618**		—		(10)
	$	**1,158**	$	931	$	466
Effective income tax rate on adjusted net earnings from operations [2]		**25%**		21%		27%

(1) Includes North America Exploration and Production, Midstream and Refining, and Oil Sands Mining and Upgrading segments.
(2) Excludes the impact of current and deferred PRT expense and other current income tax expense.

The effective income tax rate for 2019 and the comparable years included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings.

The current corporate income tax and PRT in the North Sea in 2019 and the comparable years included the impact of carrybacks of abandonment expenditures related to decommissioning activities at the Company's platforms in the North Sea.

During 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by $1,618 million.

During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $10 million.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's reported results of operations, financial position or liquidity.

During 2019, the Company filed Scientific Research and Experimental Development claims of approximately $250 million (2018 – $265 million; 2017 – $345 million) relating to qualifying research and development expenditures for Canadian income tax purposes.

Net Capital Expenditures [1]

($ millions)		2019		2018		2017
Exploration and Evaluation						
Net property acquisitions (dispositions) [2][3]	**$**	**90**	$	(74)	$	26
Net expenditures		**74**		122		123
Total Exploration and Evaluation		**164**		48		149
Property, Plant and Equipment						
Net property acquisitions [2][3]		**3,208**		98		1,219
Well drilling, completion and equipping		**775**		1,446		1,001
Production and related facilities		**1,028**		1,262		860
Capitalized interest and other		**81**		106		91
Total Property, Plant and Equipment		**5,092**		2,912		3,171
Total Exploration and Production		**5,256**		2,960		3,320
Oil Sands Mining and Upgrading						
Project costs [4]		**436**		438		821
Sustaining capital		**933**		665		561
Turnaround costs		**118**		112		155
Acquisitions of Exploration and Evaluation assets [3][5]		**—**		218		219
Net property acquisitions [3]		**—**		—		11,604
Capitalized interest and other		**38**		14		76
Total Oil Sands Mining and Upgrading		**1,525**		1,447		13,436
Midstream and Refining		**10**		13		80
Abandonments [6]		**296**		290		274
Head office		**34**		21		19
Total net capital expenditures	**$**	**7,121**	$	4,731	$	17,129
By segment						
North America [2][3]	**$**	**4,831**	$	2,671	$	3,056
North Sea		**196**		131		160
Offshore Africa		**229**		158		104
Oil Sands Mining and Upgrading [3][5]		**1,525**		1,447		13,436
Midstream and Refining		**10**		13		80
Abandonments [6]		**296**		290		274
Head office		**34**		21		19
Total	**$**	**7,121**	$	4,731	$	17,129

(1) Net capital expenditures exclude the impact of lease assets and fair value and revaluation adjustments, and include non-cash transfers of property, plant and equipment to inventory due to change in use.
(2) During 2019, cash consideration for the acquisition of assets from Devon included $91 million for exploration and evaluation assets and $3,126 million for property, plant and equipment.
(3) During 2017, total purchase consideration for the acquisition of AOSP of $12,157 million included $26 million of exploration and evaluation assets and $308 million of property, plant and equipment within the North America segment, and $219 million of exploration and evaluation assets and $11,604 million of property, plant and equipment within the Oil Sands Mining and Upgrading segment.
(4) Includes Horizon Phase 2/3 construction costs.
(5) In the third quarter of 2018, total purchase consideration for the acquisition of the Joslyn oil sands project included $222 million for exploration and evaluation assets and $4 million for asset retirement obligations assumed. In the fourth quarter of 2018, following integration of the Joslyn oil sands project into the Horizon mine plan and determination of proved crude oil reserves, the exploration and evaluation assets were transferred to property, plant, and equipment.
(6) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

NET CAPITAL EXPENDITURES, AS RECONCILED TO CASH FLOWS USED IN INVESTING ACTIVITIES

($ millions)		2019		2018		2017
Cash flows used in investing activities	$	**7,255**	$	4,814	$	13,102
Net change in non-cash working capital (1) (2)		**(430)**		(345)		22
Investment in other long-term assets		**—**		(28)		(87)
Share consideration in business acquisitions		**—**		—		3,818
Abandonment expenditures (3)		**296**		290		274
Net capital expenditures	$	**7,121**	$	4,731	$	17,129

(1) Includes net working capital and other long-term assets of $195 million related to the acquisition of assets from Devon in 2019.
(2) Includes net working capital of $291 million related to the acquisition of AOSP in 2017.
(3) The Company excludes abandonment expenditures from "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" in the "Financial and Operational Highlights" section of this MD&A.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core areas. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production expenses.

Net capital expenditures for 2019 were $7,121 million compared with $4,731 million for 2018 (2017 – $17,129 million). Net capital expenditures for 2019 included $3,217 million of cash consideration to acquire assets from Devon.

DRILLING ACTIVITY (1)

(number of wells)	2019	2018	2017
Net successful natural gas wells	**19**	18	21
Net successful crude oil wells (2)	**86**	483	495
Dry wells	**3**	9	7
Stratigraphic test / service wells	**447**	615	289
Total	**555**	1,125	812
Success rate (excluding stratigraphic test / service wells)	**97%**	98%	99%

(1) Includes drilling activity for North America and International segments.
(2) Includes bitumen wells.

North America

During 2019, the Company targeted 20 net natural gas wells, 42 net primary heavy crude oil wells, 3 net bitumen (thermal oil) wells and 37 net wells targeting light crude oil.

North Sea

During 2019, the Company completed 5 gross production wells (4.9 on a net basis) and 2 gross injection wells (1.9 on a net basis), successfully completing the 2019 drilling program in the North Sea.

Offshore Africa

During 2019, the Company completed 1 gross production well (0.6 on a net basis) and 2 gross injection wells (1.2 on a net basis) at Baobab and 1 gross appraisal well (0.6 on a net basis) at Kossipo.

Liquidity and Capital Resources

($ millions, except ratios)		2019		2018		2017
Working capital [1]	$	241	$	(601)	$	513
Long-term debt [2] [3]	$	20,982	$	20,623	$	22,458
Less: cash and cash equivalents		139		101		137
Long-term debt, net	$	20,843	$	20,522	$	22,321
Share capital	$	9,533	$	9,323	$	9,109
Retained earnings		25,424		22,529		22,612
Accumulated other comprehensive income (loss)		34		122		(68)
Shareholders' equity	$	34,991	$	31,974	$	31,653
Debt to book capitalization [3] [4]		37%		39%		41%
Debt to market capitalization [3] [5]		30%		34%		29%
After-tax return on average common shareholders' equity [6]		16%		8%		8%
After-tax return on average capital employed [3] [7]		11%		6%		6%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.
(2) Includes the current portion of long-term debt (2019 - $2,391 million, 2018 - $1,141 million, 2017 - $1,877 million).
(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and premiums and transaction costs.
(4) Calculated as net current and long-term debt; divided by the book value of common shareholders' equity plus net current and long-term debt.
(5) Calculated as net current and long-term debt; divided by the market value of common shareholders' equity plus net current and long-term debt.
(6) Calculated as net earnings for the year; as a percentage of average common shareholders' equity for the year.
(7) Calculated as net earnings plus after-tax interest and other financing expense for the year; as a percentage of average capital employed for the year.

As at December 31, 2019, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of this MD&A. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated cash flows from operating activities supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long-term and support its growth strategy.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
  - During 2019, the Company fully repaid and cancelled the $1,800 million non-revolving term credit facility scheduled to mature in May 2020.
  - During 2019, the $2,200 million non-revolving term credit facility, originally due October 2020, was extended to February 2023 and increased to $2,650 million.
  - During 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon. The facility matures in June 2022 and is subject to annual amortization of 5% of the original balance.
  - Borrowings under the Company's non-revolving credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2019, the non-revolving credit facilities were fully drawn.
  - During 2019, the Company extended the $2,425 million revolving syndicated credit facility, of which $330 million was originally due June 2019 and $2,095 million was originally due June 2021, to June 2023. The other $2,425 million revolving credit facility matures in June 2022. Each of the $2,425 million revolving credit facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.

- During 2019, the Company reduced the £15 million demand credit facility, related to the Company's North Sea operations, to £5 million.
- During 2019, the Company repaid $500 million of 2.60% medium-term notes and $500 million of 3.05% medium-term notes.
- The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
- During 2019, the Company filed new base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, expiring in August 2021, and replacing the Company's previous base shelf prospectuses, which would have expired in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages. The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at December 31, 2019, the Company was in compliance with this covenant; and
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default.

As at December 31, 2019, the Company had in place revolving bank credit facilities of $4,959 million of which $4,737 million was available. Additionally, the Company had in place fully drawn term credit facilities of $6,650 million. This excludes certain other dedicated credit facilities supporting letters of credit.

As at December 31, 2019, the Company had total US dollar denominated debt with a carrying amount of $15,102 million (US$11,649 million), before transaction costs and original issue discounts. This included $6,545 million (US$5,049 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$3,999 million). The fixed repayment amount of these hedging instruments is $6,429 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $116 million to $14,986 million as at December 31, 2019.

Net long-term debt was $20,843 million at December 31, 2019, resulting in a debt to book capitalization ratio of 37% (December 31, 2018 – 39%, December 31, 2017 – 41%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at December 31, 2019 are discussed in note 11 to the Company's audited consolidated financial statements.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. As at December 31, 2019, 140,000 MMbtu/d of currently forecasted natural gas volumes were hedged using AECO basis swaps for January 2020 to March 2020. Additionally, at December 31, 2019, 102,500 GJ/d of currently forecasted natural gas volumes were hedged using AECO fixed price swaps for April 2020 to October 2020. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2019 are discussed in note 19 of the Company's audited consolidated financial statements.

The maturity dates of long-term debt and other long-term liabilities and related interest payments were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt (1)	$ 2,391	$ 1,552	$ 8,921	$ 8,226
Other long-term liabilities (2)	$ 370	$ 196	$ 436	$ 1,014
Interest and other financing expense (3)	$ 881	$ 813	$ 1,771	$ 4,856

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.
(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows: less than one year, $233 million; one to less than two years, $171 million; two to less than five years, $391 million; and thereafter, $1,014 million.
(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2019.

SHARE CAPITAL

As at December 31, 2019, there were 1,186,857,000 common shares outstanding (December 31, 2018 – 1,201,886,000 common shares) and 47,646,000 stock options outstanding. As at March 17, 2020, the Company had 1,180,854,000 common shares outstanding and 53,143,000 stock options outstanding.

On March 4, 2020, the Board of Directors approved an increase in the quarterly dividend to $0.425 per common share, beginning with the dividend payable on April 1, 2020. On March 6, 2019, the Board of Directors approved an increase in the quarterly dividend to $0.375 per common share. On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share. On March 1, 2017, the Board of Directors approved an increase in the quarterly dividend to $0.275 per common share. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On May 21, 2019, the Company's application was approved for a Normal Course Issuer Bid ("NCIB") to purchase through the facilities at the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 59,729,706 common shares, over a 12-month period commencing May 23, 2019 and ending May 22, 2020. The Company's NCIB approved in May 2018 expired on May 22, 2019.

During 2019, the Company purchased for cancellation 25,900,000 common shares at a weighted average price of $36.32 per common share for a total cost of $941 million. Retained earnings were reduced by $738 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2019, the Company purchased 6,970,000 common shares at a weighted average price of $38.84 per common share for a total cost of $271 million.

Commitments and Contingencies

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2019 [1]:

($ millions)	2020	2021	2022	2023	2024	Thereafter
Product transportation [2] [3]	$ 730	$ 722	$ 637	$ 726	$ 699	$ 7,907
North West Redwater Partnership service toll [4]	$ 133	$ 167	$ 157	$ 164	$ 156	$ 2,815
Offshore vessels and equipment	$ 69	$ 63	$ 9	$ —	$ —	$ —
Field equipment and power	$ 27	$ 21	$ 20	$ 21	$ 20	$ 249
Other	$ 26	$ 20	$ 17	$ 17	$ 17	$ 30

(1) Subsequent to adoption of IFRS 16, the Company reports its payments for lease liabilities in the maturity table in the 'Liquidity and Capital Resources' section of this MD&A.

(2) On June 27, 2019, the Company assumed $2,381 million of product transportation commitments related to the acquisition of assets from Devon.

(3) Includes commitments pertaining to a 20 year product transportation agreement on the Trans Mountain Pipeline Expansion. In addition, the Company has entered into certain product transportation agreements on pipelines that have not yet received regulatory and other approvals. The Company may be required to reimburse certain construction costs to the service provider under certain conditions.

(4) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, currently consisting of interest and fees, with principal repayments beginning in 2020. Included in the cost of service tolls is $1,260 million of interest payable over the 30 year tolling period.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of its various development projects. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

Reserves

For the years ended December 31, 2019, 2018 and 2017, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's proved and proved plus probable crude oil, NGLs and natural gas reserves. The evaluation and review was conducted and prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

The following are reconciliation tables of the company gross proved and proved plus probable reserves using forecast prices and costs as at the effective date of December 31, 2019:

Proved Reserves	**Light and Medium Crude Oil**	**Primary Heavy Crude Oil**	**Pelican Lake Heavy Crude Oil**	**Bitumen (Thermal Oil)**	**Synthetic Crude Oil**	**Natural Gas**	**Natural Gas Liquids**	**Barrels of Oil Equivalent**
	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(Bcf)	(MMbbl)	(MMBOE)
December 31, 2018	399	182	305	1,540	6,091	6,652	267	9,893
Discoveries	—	—	—	—	—	—	—	—
Extensions	3	6	—	17	385	112	11	440
Infill Drilling	5	5	—	—	—	206	8	52
Improved Recovery	—	—	—	237	—	2	—	238
Acquisitions	2	46	—	769	—	35	1	823
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(5)	(3)	(3)	—	—	(228)	(5)	(54)
Technical Revisions	(9)	(3)	12	(64)	20	225	11	3
Production	(37)	(30)	(21)	(61)	(144)	(544)	(16)	(401)
December 31, 2019 (1)	**357**	**202**	**293**	**2,438**	**6,352**	**6,460**	**275**	**10,993**

Proved Plus Probable Reserves	**Light and Medium Crude Oil**	**Primary Heavy Crude Oil**	**Pelican Lake Heavy Crude Oil**	**Bitumen (Thermal Oil)**	**Synthetic Crude Oil**	**Natural Gas**	**Natural Gas Liquids**	**Barrels of Oil Equivalent**
	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(Bcf)	(MMbbl)	(MMBOE)
December 31, 2018	575	252	445	3,059	7,032	9,734	397	13,382
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	12	—	26	—	177	17	89
Infill Drilling	6	7	—	—	—	476	15	108
Improved Recovery	—	—	—	329	—	3	—	329
Acquisitions	2	68	—	955	—	42	1	1,033
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(4)	(3)	(3)	—	—	(266)	(6)	(60)
Technical Revisions	(28)	(12)	4	(198)	9	(16)	(1)	(228)
Production	(37)	(30)	(21)	(61)	(144)	(544)	(16)	(401)
December 31, 2019 (1)	**519**	**293**	**425**	**4,108**	**6,897**	**9,607**	**408**	**14,252**

(1) Information in the reserves data tables may not add due to rounding. BOE values as presented may not calculate due to rounding.

At December 31, 2019, the company gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 9,917 MMbbl, and company gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 12,651 MMbbl. Proved reserves additions and revisions replaced 465% of 2019 production. Additions to proved reserves resulting from exploration and development activities, acquisitions, dispositions and future offset additions amounted to 1,494 MMbbl, and additions to proved plus probable reserves amounted to 1,443 MMbbl. Net negative revisions amounted to 51 MMbbl for proved reserves and 241 MMbbl for proved plus probable reserves, primarily due to technical revisions.

At December 31, 2019, the company gross proved natural gas reserves totaled 6,460 Bcf, and company gross proved plus probable natural gas reserves totaled 9,607 Bcf. Proved reserves additions and revisions replaced 65% of 2019 production. Additions to proved reserves resulting from exploration and development activities, acquisitions, dispositions and future offset additions amounted to 355 Bcf, and additions to proved plus probable reserves amounted to 698 Bcf. Net negative revisions amounted to 4 Bcf for proved reserves and 282 Bcf for proved plus probable reserves, primarily due to economic factors.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and related net present value of future net revenue of the remaining reserves. Additional reserves information is annually disclosed in the AIF.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States FASB Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual report on Form 40-F filed with the SEC and in the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

Risks and Uncertainties

The Company is exposed to various operational risks inherent in the exploration, development, production and marketing of crude oil and NGLs and natural gas and the mining, extracting and upgrading of bitumen into SCO. These inherent risks include, but are not limited to, the following:

- Volatility in the prevailing prices of crude oil and NGLs and natural gas;
- The ability to find, produce and replace reserves, whether sourced from exploration, improved recovery or acquisitions, at a reasonable cost, including the risk of reserves revisions due to economic and technical factors. Reserves revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Reservoir quality and uncertainty of reserves estimates;
- Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
- Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting and upgrading the Company's bitumen products;
- Timing and success of integrating the business and operations of acquired companies and assets;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
- Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
- Foreign exchange risk due to the effect of fluctuating exchange rates on the Company's US dollar denominated debt and revenue from sales predominantly based on US dollar denominated benchmarks;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;
- Future legislative and regulatory developments related to environmental regulation, including GHG and carbon;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations, including but not limited to restrictions on production;
- Changing royalty regimes;
- Business interruptions because of unexpected events such as fires or explosions whether caused by human error or nature, severe storms and other calamitous acts of nature, blowouts, freeze-ups, mechanical or equipment failures of facilities and infrastructure and other similar events affecting the Company or other parties whose operations or assets directly or indirectly impact the Company and that may or may not be financially recoverable;
- Epidemics or pandemics, such as the newly identified COVID-19 virus pandemic, have the potential to disrupt the Company's operations, projects and financial condition through the disruption of the local or global supply chain and transportation services, or the loss of manpower resulting from quarantines that affect the Company's labour pools in their local communities, workforce camps or operating sites or that are instituted by local health authorities as a precautionary measure, any of which may require the Company to temporarily reduce or shutdown its operations depending on the extent and severity of a potential outbreak and the areas or operations impacted. Depending on the severity, a large scale global epidemic or pandemic could impact the international demand for commodities and have a corresponding impact on the prices realized by the Company, which could have a material adverse effect on the Company's financial condition;
- The ability to secure adequate transportation for products which could be affected by pipeline constraints, the construction by third parties of new or expansion of existing pipeline capacity and other factors;
- The access to markets for the Company's products;
- The risk of significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach that could adversely affect the Company's operations;
- Liquidity risk related to the Company's ability to fulfill financial obligations as they become due or ability to liquidate assets in a timely manner at a reasonable price; and
- Other circumstances affecting revenue and expenses.

The Company uses a variety of means to seek to mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company seeks to manage these risks by monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default. Derivative financial instruments are periodically utilized to help ensure targets are met and to manage commodity price, foreign currency and interest rate exposures. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company seeks to manage this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions. Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper and access to debt capital markets, to meet obligations as they become due. The Company has implemented cyber security protocols and procedures designed to reduce the risk of failure or a significant breach of the Company's information technology systems and related data and control systems.

The Company has safety, integrity and environmental management systems to recover and process crude oil and natural gas resources safely, efficiently, and in an environmentally sustainable manner and mitigate risk.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

For additional details regarding the Company's risks and uncertainties, refer to the Company's AIF for the year ended December 31, 2019.

Environment

The Company has a Corporate Statement on Environmental Management which affirms that environmental stewardship is a fundamental value of the Company. The Company continues to invest in people, proven and new technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner. Environmental, social, economic and health considerations are evaluated in new project designs and in operations to improve environmental performance. Processes are employed to avoid, mitigate, minimize or compensate for environmental effects. Working with local communities, the Company considers the interests and values of the people using the land in proximity to its operations, and where appropriate, adapts projects to recognize those matters.

The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation compliance, particularly in North America and the North Sea. Existing and expected legislation and regulations may require the Company to address and mitigate the effect of its activities on the environment. The Company believes it meets all existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings.

The Company's associated environmental risk management strategies incorporate working with legislators and regulators on any new or revised policies, legislation or regulations to reflect a balanced approach to sustainable development. Specific measures in response to existing or new legislation include a focus on the Company's energy efficiency, air emissions management, water management and land management to minimize disturbance impacts. The Company's environmental risk management strategies employ an Environmental Management Plan (the "Plan"). As part of risk management, the Company develops, assesses and implements technologies and innovative practices that will improve environmental performance, often through collaborative efforts with industry partners, governments and research institutions. Details of the Plan, along with performance results, are presented to, and reviewed by, the Board of Directors quarterly.

The Plan and the Company's operating guidelines focus on minimizing the impact of operations while meeting regulatory requirements, regional management frameworks for air quality and emissions, ground and surface water and biodiversity, industry operating standards and guidelines, and internal corporate standards. Training and due diligence for operators and contractors is key to the effectiveness of the Company's environmental management programs and the prevention of incidents to protect the environment. The Company, as part of this Plan, has implemented proactive programs that include:

- Environmental planning to assess impacts and implement avoidance and mitigation programs in order to preserve high value biodiversity;
- Continued evaluation of new technologies to reduce environmental impacts, including support for Canada's Oil Sands Innovation Alliance ("COSIA"), Petroleum Technology Alliance Canada ("PTAC") and other research institutions;
- Mitigation of the Company's climate change impacts through implementation of various CO_2 emissions reduction and carbon capture projects including: CO_2 injection for EOR, CO_2 sequestration in tailings and the Quest carbon capture and storage facility; a methane emissions reduction program, including solution gas conservation to reduce methane venting, and an equipment retrofit program to reduce methane emissions from pneumatic equipment; and optimization of efficiencies at the Company's facilities;
- Water programs to improve efficiency of use and recycle rates as well as to reduce fresh water use;
- Groundwater monitoring for all thermal in situ and mine operations;

- Effective reclamation and decommissioning programs across the Company's operations, returning sites to their former state. In North America, well abandonment and progressive reclamation of large contiguous areas of land for the enhancement of biodiversity and the establishment of functional wildlife habitats. In the Company's International operations, decommissioning activities continued in Gabon as well as Murchison and Ninian platforms in the North Sea;
- Tailings management in Oil Sands Mining to minimize fine tailings and promote reclamation;
- Monitoring programs to assess changes to biodiversity, wildlife and fisheries in order to manage construction and operation effects and to assess reclamation success;
- Participation and support for the Oil Sands Monitoring Program of regional important resources;
- An active spill prevention and management program; and
- An internal environmental management system for compliance audit and inspection programs of operating facilities.

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 3.8% (2018 – 5.0%; 2017 – 4.7%). For 2019, the Company's capital expenditures included $296 million for abandonment expenditures (2018 – $290 million; 2017 – $274 million). The Company's estimated discounted ARO at December 31, 2019 was as follows:

($ millions)		**2019**		2018
Exploration and Production				
North America	**$**	**2,792**	$	1,665
North Sea		**816**		707
Offshore Africa		**161**		134
Oil Sands Mining and Upgrading		**2,000**		1,379
Midstream and Refining		**2**		1
	$	**5,771**	$	3,886

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine sites, upgrading facilities and tailings, and offshore production platforms. Factors that affect costs include number of wells drilled, well depth, facility size and the specific environmental legislation. The estimated future costs are based on engineering estimates of current costs in accordance with present legislation, industry operating practice and the expected timing of abandonment.

GREENHOUSE GAS AND OTHER EMISSIONS

The Company has a large, diversified and balanced portfolio and a risk management strategy which incorporates an integrated GHG emissions reduction strategy and investments in technology and innovation to improve its GHG performance. The Company's integrated GHG emissions reduction strategy includes: 1) integrating emissions reduction in project planning and operations; 2) leveraging technology to create value and enhance performance; 3) investing in research and development and supporting collaboration with industry, entrepreneurs, academia and governments; 4) focusing on continuous improvement to drive long-term emissions reduction; 5) leading in carbon capture, sequestration and storage; 6) engaging in policy and regulatory development (including trading capacity and offsetting emissions); and, 7) reviewing and developing new business opportunities and trends.

The Company, through the Canadian Association of Petroleum Producers, is working with Canadian legislators and regulators as they develop and implement new GHG emission laws and regulations to support emissions reductions and properly reflect a balanced approach to sustainable development. Internally, the Company is pursuing an integrated emissions reduction strategy, to ensure that it is able to comply with existing and future emissions reduction requirements, for both GHGs and air pollutants (such as sulphur dioxide and oxides of nitrogen). The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new policies encourage technological innovation, energy efficiency, and targeted research and development while not impacting competitiveness.

Governments in jurisdictions in which the Company operates have developed or are developing GHG regulations as part of their national and international climate change commitments. The Company uses existing GHG regulations to determine the impact of compliance costs on current and future projects. The Company monitors the development of GHG regulations on an ongoing basis in the jurisdictions in which it operates to assess the impact of future regulatory developments on the Company's operations and planned projects. In Canada, the federal government has ratified the Paris climate change agreement, with a commitment to reduce GHG emissions by 30% from 2005 levels by 2030. Canada has also committed to reduce methane emissions from the upstream oil and natural gas sector by 40 - 45% by 2025, as compared to 2012 levels. The federal government is also developing: (i) a comprehensive management system for air pollutants and has released regulations pertaining to certain boilers, heaters and compressor engines operated by the Company; and (ii) a Clean Fuel Standard, which may affect production and consumption of fuels in Canada.

Carbon pricing regulatory systems in all provinces are subject to annual review by the federal government to assess the adequacy of the provincial systems against the federal Greenhouse Gas Pollution Pricing Act. Such future reviews may affect the carbon price and/or the stringency of provincial systems.

Effective January 1, 2018, the Alberta government implemented the Carbon Competitiveness Incentive Regulation (CCIR) to replace the Specified Gas Emitters Regulation, for the regulation of GHG emissions from large facilities. In 2019, nine of the Company's operated facilities: Horizon, AOSP, the Primrose/Wolf Lake, Kirby South, Jackfish, Peace River, Hays, Wapiti and the Brintnell power generation facility were subject to compliance under the regulation. Effective January 1, 2020, the CCIR was replaced with the Technology Innovation and Emissions Reduction Regulation ("TIER"). The coverage of TIER has expanded to include all of the Company's assets in Alberta (as an alternative to the federal fuel charge). The carbon price in Alberta is currently $30/tonne for emissions above the TIER-regulated limits, and the Alberta government has announced its intention to increase the price to $40/tonne in 2021 and $50/tonne in 2022, in alignment with the federal carbon pricing schedule. Facilities with emissions in previous years above 100,000 tonnes of CO_2e/year, or that have voluntarily opted into TIER are required to comply with the regulation. The non-operated Scotford Upgrader is also subject to compliance under the regulations. The non-operated North West Redwater bitumen upgrader and refinery is subject to a reduction target in 2020.

In British Columbia, carbon tax is currently being assessed at $40/tonne of CO_2e on fuel consumed and gas flared in the province, with the rate increasing to $45/tonne on April 1, 2020 and to $50/tonne of CO_2e on April 1, 2021. The British Columbia government is implementing a program (the CleanBC Plan) to partially mitigate the impact of the carbon tax increases on emissions intensive trade exposed (EITE) sectors.

As part of its Prairie Resilience Plan, the Saskatchewan government has released a regulation ("The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations") that applies to facilities emitting more than 25 kilotonnes of CO_2e annually and requires the North Tangleflags in situ heavy oil facility and the Senlac in situ heavy crude oil facility to meet reduction targets for GHG emissions in 2019. This regulation also enables facilities below the threshold to aggregate and opt into the Saskatchewan regulatory system as an alternative to the federal fuel charge.

In Manitoba, the federal output-based pricing system applies for facilities with emissions greater than or equal to 10 kilotonnes of CO_2e annually, and the federal fuel charge applies for facilities with emissions of less than 10 kilotonnes of CO_2e annually.

The federal government's methane regulation has come into effect on January 1, 2020 and will apply nationally unless provinces reach equivalency agreements with the federal government, under which the federal regulation would not be in effect for those jurisdictions which have equivalency agreements. The Alberta government has also finalized regulations to reduce methane emissions from the upstream oil and gas sector (consistent with the federal reduction target), which came into effect on January 1, 2020. In British Columbia, the provincial government has announced a methane reduction target, comparable to the federal target, and has released final regulations to achieve this target. The Saskatchewan government has also released a regulation to reduce methane emissions from oil production facilities, effective 2020.

Air pollutant standards and guidelines are being developed federally and provincially and the Company is participating in these discussions. Ambient air quality and sector based reductions in air emissions are being reviewed. Through Company and industry participation with stakeholders, guidelines are being developed that adopt a structured process to emission reductions that is commensurate with technological development and operational requirements.

In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 - 2007) of the UK National Allocation Plan, the Company operated below its CO_2 allocation. In Phase 2 (2008 - 2012) the Company's CO_2 allocation was decreased below the Company's operations emissions. In Phase 3 (2013 - 2020) the Company's CO_2 allocation was further reduced. Following the UK's withdrawal from the European Union ("EU") on January 31, 2020, the UK will continue to participate in the EU ETS for the 2020 compliance year, with decisions on the post-2020 GHG regulatory framework expected in 2020. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its offshore facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Accounting Policies and Standards

CHANGES IN ACCOUNTING POLICIES

IFRS 16 "Leases"

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaced IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and generally requires balance sheet recognition for all leases. Certain short-term (12 months or less) and low-value leases are exempt from the requirements, and the Company continues to treat these leases as expenses. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are also exempt from the standard.

The Company adopted IFRS 16 on January 1, 2019 using the modified retrospective approach with no impact to opening retained earnings at the date of adoption. In accordance with the transitional provisions in the standard, balances reported in the comparative periods have not been restated and continue to be reported using the Company's previous accounting policy under IAS 17.

On adoption, the Company applied the following practical expedients under the standard. Certain expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- leases with a remaining lease term of twelve months or less as at January 1, 2019 were treated as short-term leases;
- exclusion of initial direct costs for the measurement of lease assets at the date of initial application; and
- the application of the Company's previous assessment for onerous contracts under IAS 37, instead of re-assessing impairment on the Company's lease assets as at January 1, 2019.

The Company did not apply any practical expedients pertaining to grandfathering of leases assessed under the previous standard.

In connection with the adoption of IFRS 16, the Company recognized lease liabilities (included in other long-term liabilities) of $1,539 million, measured at the present value of the remaining lease payments, discounted at the Company's incremental borrowing rate at the transition date. Lease assets were measured at an amount equal to the lease liability. Under the new standard, the Company reports cash outflows for payment of the principal portion of the lease liability as cash flows used in financing activities. The interest portion of the lease payments is classified as cash flows from operating activities.

For further details of the Company's lease assets and lease liabilities on transition to the new Leases standard at January 1, 2019 and as at December 31, 2019, refer to the audited consolidated financial statements for the year ended December 31, 2019.

The impacts of the adoption of IFRS 16 are discussed within the respective sections of this MD&A. The most significant impacts of the adoption of the new Leases standard are as follows:

- Cash flow from operating activities and adjusted funds flow increased as the principal portion of lease payments, previously classified as cash flows from operating activities is now reported as cash flows used in financing activities;
- Increased depletion, depreciation and amortization expense and interest expense;
- Decreased production expense, transportation expense and administration expense; and
- Commitments for leases, previously reported in the "Commitments and Contingencies" section of this MD&A, are now reported in the maturity table in the "Liquidity and Capital Resources" section of this MD&A.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In October 2018, the IASB issued amendments to IFRS 3 "Definition of a Business" that narrowed and clarified the definition of a business. The amendments permit a simplified assessment of whether an acquired set of activities and assets is a group of assets rather than a business. The amendments are effective January 1, 2020 with earlier adoption permitted. The amendments apply to business combinations after the date of adoption. The Company prospectively adopted the amendments on January 1, 2020.

In October 2018, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" and IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors". The amendments make minor changes to the definition of the term "material" and align the definition across all IFRS Standards. Materiality is used in making judgments related to the preparation of financial statements. The amendments are effective January 1, 2020 with earlier adoption permitted. The Company prospectively adopted the amendments on January 1, 2020.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in this MD&A and the audited consolidated financial statements for the year ended December 31, 2019.

A) Depletion, Depreciation and Amortization and Impairment

Exploration and evaluation ("E&E") costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. The judgements associated with the estimation of proved reserves are described below in "Crude Oil and Natural Gas Reserves".

An alternative acceptable accounting method for E&E costs under IFRS 6 "Exploration for and Evaluation of Mineral Resources" is to charge exploratory dry holes and geological and geophysical exploration costs incurred after having obtained the legal rights to explore an area against net earnings in the period incurred rather than capitalizing to E&E assets.

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of related Cash Generating Units ("CGUs"), aggregated at a segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and production costs, discount rates and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Crude oil and natural gas properties in the Exploration and Production segments are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future estimated development expenditures required to develop proved reserves. Estimates of proved reserves have a significant impact on net earnings, as they are a key input to the calculation of depletion expense.

The Company assesses property, plant and equipment for impairment discounted at rates currently ranging from 10% to 12% whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low commodity prices for an extended period, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs an impairment test related to the specific assets at the CGU level.

B) Crude Oil and Natural Gas Reserves

Reserves estimates are based on engineering data, estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations and judgements. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion, depreciation and amortization charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of E&E and property, plant and equipment carrying amounts.

C) Asset Retirement Obligations

The Company is required to recognize a liability for ARO associated with its property, plant and equipment. An ARO liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total ARO amount. These individual assumptions may be subject to change.

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's weighted average credit-adjusted risk-free interest rate, which is currently 3.8%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

D) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted as at the date of the balance sheet. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

E) Risk Management Activities

The Company periodically uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The carrying amount of a risk management liability is adjusted for the Company's own credit risk. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

F) Purchase Price Allocations

Purchase prices related to business combinations are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties, together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation and amortization expense and impairment tests.

The Company has made various assumptions in determining the fair values of acquired assets and liabilities. The most significant assumptions and judgements relate to the estimation of the fair value of crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates crude oil and natural gas reserves. Reserves estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgements associated with these estimated reserves are described above in "Crude Oil and Natural Gas Reserves". Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

G) Share-Based Compensation

The Company has made various assumptions in estimating the fair values of stock options granted including expected volatility, expected exercise behavior and future forfeiture rates. At each period end, stock options outstanding are remeasured for changes in the fair value of the liability.

H) Leases

Purchase, extension and termination options are included in certain of the Company's leases to provide operational flexibility. To measure the lease liability, the Company uses judgment to assess the likelihood of exercising these options. These assessments are reviewed when significant events or circumstances indicate that the likelihood of exercising these options may have changed. The Company also uses estimates to determine its incremental borrowing costs if the interest rate implicit in the lease is not readily determinable.

Control Environment

The Company's management, including the President and the Chief Financial Officer and Senior Vice-President, Finance, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2019, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized and reported within the time periods specified and such information is accumulated and communicated to the Company's management to allow timely decisions regarding required disclosures.

The Company's management, including the President and the Chief Financial Officer and Senior Vice-President, Finance, also evaluated the effectiveness of internal control over financial reporting as at December 31, 2019, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2019 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal control over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Outlook

The Company continues to implement its strategy of maintaining a large portfolio of varied projects, which the Company believes will enable it, over an extended period of time, to provide consistent growth in production and create shareholder value. Annual budgets are developed, scrutinized throughout the year and revised if necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas.

2020 CAPITAL BUDGET

Effective and efficient operations will continue to be a focus for the Company in 2020. Our 2020 capital budget is flexible and disciplined and was originally targeted, when finalized on December 4, 2019, at approximately $4,050 million, driving corporate production guidance volumes of between 1,137,000 and 1,207,000 BOE/d. Subsequent to year end 2019, in early March 2020, as a result of the volatility in crude oil pricing, Canadian Natural reduced its 2020 capital budget by approximately $100 million to $3,950 million. With the continued volatility in commodity pricing, the Company in mid-March 2020 identified and implemented further opportunities to reduce its 2020 capital spending budget to approximately $2,960 million, but with no impact to our stated production guidance volumes of between 1,137,000 and 1,207,000 BOE/d. Decisions regarding additional opportunities to further reduce capital spending will be made as part of the Company's prudent management of its capital expenditures.

Other

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flows from operating activities and net earnings due to changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2019, excluding mark-to-market gains (losses) on risk management activities and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

		Cash flows from Operating Activities ($ millions)		**Cash flows from Operating Activities** (per common share, basic)		**Net earnings** ($ millions)		**Net earnings** (per common share, basic)
Price changes								
Crude oil – WTI US$1.00/bbl								
Excluding financial derivatives	$	292	$	0.24	$	292	$	0.24
Including financial derivatives	$	292	$	0.24	$	292	$	0.24
Natural gas – AECO C$0.10/Mcf (1)								
Excluding financial derivatives	$	23	$	0.02	$	23	$	0.02
Including financial derivatives	$	21	$	0.02	$	21	$	0.02
Volume changes								
Crude oil – 10,000 bbl/d	$	128	$	0.11	$	100	$	0.08
Natural gas – 10 MMcf/d	$	2	$	—	$	—	$	—
Foreign currency rate change								
$0.01 change in US$ (1)								
Including financial derivatives	$	161 - 165	$	0.14	$	52	$	0.04
Interest rate change – 1%	$	50	$	0.04	$	50	$	0.04

(1) For details of financial instruments in place, refer to note 19 to the Company's audited consolidated financial statements as at December 31, 2019.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	**Q2**	**Q3**	**Q4**	**2019**	2018	2017
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	**319,437**	**344,665**	**450,662**	**506,571**	**405,970**	350,961	359,449
North America – Oil Sands Mining and Upgrading	**416,206**	**374,500**	**432,203**	**357,856**	**395,133**	426,190	282,026
North Sea	**25,714**	**27,594**	**27,454**	**30,860**	**27,919**	23,965	23,426
Offshore Africa	**22,155**	**23,650**	**21,227**	**18,495**	**21,371**	19,662	20,335
Total	**783,512**	**770,409**	**931,546**	**913,782**	**850,393**	820,778	685,236
Natural gas (MMcf/d)							
North America	**1,454**	**1,482**	**1,425**	**1,411**	**1,443**	1,490	1,601
North Sea	**28**	**23**	**20**	**25**	**24**	32	39
Offshore Africa	**28**	**27**	**24**	**19**	**24**	26	22
Total	**1,510**	**1,532**	**1,469**	**1,455**	**1,491**	1,548	1,662
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	**561,755**	**591,738**	**688,175**	**741,673**	**646,443**	599,310	626,230
North America – Oil Sands Mining and Upgrading	**416,206**	**374,500**	**432,203**	**357,856**	**395,133**	426,190	282,026
North Sea	**30,466**	**31,346**	**30,758**	**35,052**	**31,915**	29,264	29,989
Offshore Africa	**26,785**	**28,216**	**25,225**	**21,695**	**25,466**	24,049	24,019
Total	**1,035,212**	**1,025,800**	**1,176,361**	**1,156,276**	**1,098,957**	1,078,813	962,264

PER UNIT RESULTS – EXPLORATION AND PRODUCTION

	Q1	Q2	Q3	Q4	2019	2018	2017
Crude oil and NGLs ($/bbl) [1]							
Sales price [2]	$ 53.98	$ 63.45	$ 55.19	$ 49.60	$ 55.08	$ 46.92	$ 48.57
Transportation	3.26	3.35	3.69	3.53	3.48	3.08	2.80
Realized sales price, net of transportation	50.72	60.10	51.50	46.07	51.60	43.84	45.77
Royalties	5.95	6.35	6.02	6.03	6.08	5.08	5.24
Production expense	16.04	14.42	13.25	12.46	13.81	15.69	14.89
Netback	$ 28.73	$ 39.33	$ 32.23	$ 27.58	$ 31.71	$ 23.07	$ 25.64
Natural gas ($/Mcf) [1]							
Sales price [2]	$ 3.09	$ 1.98	$ 1.64	$ 2.64	$ 2.34	$ 2.61	$ 2.76
Transportation	0.46	0.40	0.40	0.43	0.42	0.47	0.39
Realized sales price, net of transportation	2.63	1.58	1.24	2.21	1.92	2.14	2.37
Royalties	0.12	0.08	0.01	0.11	0.08	0.08	0.11
Production expense	1.33	1.23	1.12	1.17	1.22	1.36	1.27
Netback	$ 1.18	$ 0.27	$ 0.11	$ 0.93	$ 0.62	$ 0.70	$ 0.99
Barrels of oil equivalent ($/BOE) [1]							
Sales price [2]	$ 39.27	$ 43.38	$ 40.36	$ 39.20	$ 40.50	$ 34.62	$ 35.54
Transportation	3.06	2.97	3.27	3.24	3.14	2.96	2.66
Realized sales price, net of transportation	36.21	40.41	37.09	35.96	37.36	31.66	32.88
Royalties	3.78	4.06	4.07	4.37	4.09	3.27	3.40
Production expense	12.68	11.68	11.11	10.79	11.49	12.71	11.95
Netback	$ 19.75	$ 24.67	$ 21.91	$ 20.80	$ 21.78	$ 15.68	$ 17.53

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING

	Q1	Q2	Q3	Q4	2019	2018	2017
Crude oil and NGLs ($/bbl) [1]							
SCO sales price [2]	$ 65.86	$ 74.98	$ 71.60	$ 68.67	$ 70.18	$ 68.61	$ 63.98
Bitumen royalties [3]	2.31	3.79	3.76	3.47	3.31	3.09	1.64
Transportation	1.17	1.53	1.16	1.33	1.29	1.61	1.54
Adjusted production costs	21.46	24.17	18.82	23.02	21.75	21.05	23.40
Netback	$ 40.92	$ 45.49	$ 47.86	$ 40.85	$ 43.83	$ 42.86	$ 37.40

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.
(2) Net of blending and feedstock costs.
(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2019	2018
TSX – C$						
Trading volume (thousands)	**241,284**	**216,340**	**226,800**	**219,589**	**904,013**	806,254
Share Price ($/share)						
High	**$ 38.45**	**$ 42.56**	**$ 38.00**	**$ 42.40**	**$ 42.56**	$ 49.08
Low	**$ 31.52**	**$ 34.25**	**$ 30.01**	**$ 32.26**	**$ 30.01**	$ 30.11
Close	**$ 36.69**	**$ 35.31**	**$ 35.25**	**$ 42.00**	**$ 42.00**	$ 32.94
Market capitalization as at December 31 ($ millions)					**$ 49,848**	$ 39,590
Shares outstanding (thousands)					**1,186,857**	1,201,886
NYSE – US$						
Trading volume (thousands)	**200,874**	**164,274**	**163,447**	**151,102**	**679,697**	796,971
Share Price ($/share)						
High	**$ 29.04**	**$ 31.77**	**$ 28.71**	**$ 32.56**	**$ 32.56**	$ 38.19
Low	**$ 23.09**	**$ 25.42**	**$ 22.58**	**$ 24.20**	**$ 22.58**	$ 21.85
Close	**$ 27.50**	**$ 26.97**	**$ 26.63**	**$ 32.35**	**$ 32.35**	$ 24.13
Market capitalization as at December 31 ($ millions)					**$ 38,395**	$ 29,002
Shares outstanding (thousands)					**1,186,857**	1,201,886

Consolidated Financial Statements

Table of Contents

Management's Report

The accompanying consolidated financial statements of Canadian Natural Resources Limited (the "Company") and all other information contained elsewhere in this Annual Report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies described in the accompanying notes. Where necessary, management has made informed judgements and estimates in accounting for transactions that were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board as appropriate in the circumstances. The financial information presented elsewhere in the Annual Report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized and recorded, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to audit and provide their independent audit opinions on the following:

- the Company's consolidated financial statements as at and for the year ended December 31, 2019; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2019.

Their report is presented with the consolidated financial statements.

The Board of Directors (the "Board") is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board exercises this responsibility through the Audit Committee of the Board, which is comprised entirely of independent directors. The Audit Committee meets with management and the independent auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board for approval. The consolidated financial statements have been approved by the Board on the recommendation of the Audit Committee.

TIM S. MCKAY
President

MARK STAINTHORPE, CFA
Chief Financial Officer and Senior Vice-President, Finance

RONALD D. KIM, CA
Vice-President, Finance and Principal Accounting Officer

Calgary, Alberta, Canada

March 18, 2020

Management's Assessment of Internal Control over Financial Reporting

Management of Canadian Natural Resources Limited (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as defined in Rules 13a-15(f) and 15d-15(f) under the United States Securities Exchange Act of 1934, as amended.

Management, including the Company's President and the Company's Chief Financial Officer and Senior Vice-President, Finance, performed an assessment of the Company's internal control over financial reporting based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on the assessment, management has concluded that the Company's internal control over financial reporting is effective as at December 31, 2019. Management recognizes that all internal control systems have inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has provided an opinion on the Company's internal control over financial reporting as at December 31, 2019, as stated in their accompanying Report of Independent Registered Public Accounting Firm.

TIM S. MCKAY
President

MARK STAINTHORPE, CFA
Chief Financial Officer and Senior
Vice-President, Finance

Calgary, Alberta, Canada

March 18, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Canadian Natural Resources Limited

OPINIONS ON THE FINANCIAL STATEMENTS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

We have audited the accompanying consolidated balance sheets of Canadian Natural Resources Limited and its subsidiaries (together, the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of earnings, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and its financial performance and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019 due to the adoption of IFRS 16, Leases.

BASIS FOR OPINIONS

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

DEFINITION AND LIMITATIONS OF INTERNAL CONTROL OVER FINANCIAL REPORTING

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

CRITICAL AUDIT MATTERS

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The impact of Crude Oil and Natural Gas Reserves on Property, Plant and Equipment Assets in the North America Exploration and Production and Oil Sands Mining and Upgrading segments

As described in Notes 1, 4, and 7 to the Company's consolidated financial statements, the property, plant and equipment ("PP&E") balances in the North America Exploration and Production and Oil Sands Mining and Upgrading segments was $26.1 billion and $38.8 billion, respectively, as at December 31, 2019. Depletion, depreciation and amortization ("DD&A") expense for the North America Exploration and Production and Oil Sands Mining and Upgrading segments was $3.2 billion and $1.6 billion, respectively, for the year ended December 31, 2019. In accordance with the Company's accounting policies, crude oil and natural gas properties in the North America Exploration and Production segment, excluding major components, and mine-related costs in the Oil Sands Mining and Upgrading segment are depleted using the unit-of-production method based on proved reserves. PP&E assets are grouped for recoverability assessment purposes into cash generating units ("CGUs") and a CGU's recoverable amount is the higher of its fair value less costs of disposal and its value in use. The assessment of a CGU's recoverability requires the use of estimates and assumptions, including information on future commodity prices, expected production volumes, quantity of crude oil and natural gas reserves, asset retirement obligations, future development and operating costs, after-tax discount rates, and income taxes. Estimates of the Company's crude oil and natural gas reserves are based on engineering data, estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations, and judgements.

Management utilizes third party specialists, specifically independent qualified reserve evaluators to evaluate, review and report to the Company's management and Board of Directors on its estimates of crude oil and natural gas reserves. These estimates are utilized for both the determination of the recoverable amounts of PP&E and the calculation of DD&A expense.

The principal considerations for our determination that performing procedures relating to the impact of crude oil and natural gas reserves on PP&E assets in the North America Exploration and Production and Oil Sands Mining and Upgrading segments is a critical audit matter are that there was a significant amount of judgment required by management, including the use of specialists, when developing the estimates, specifically related to the estimates of crude oil and natural gas reserves and the recoverable amount of the PP&E assets in the North America Exploration and Production and Oil Sands Mining and Upgrading segments. This led to a high degree of auditor judgment, effort, and subjectivity in performing procedures and evaluating evidence obtained related to the significant assumptions used in developing the estimates, including estimates of expected future rates of production, future commodity pricing, and future development and operating costs.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of internal controls in the North America Exploration and Production and Oil Sands Mining and Upgrading segments relating to management's estimates of the Company's crude oil and natural gas reserves, management's assessment of PP&E recoverability, and the calculation of DD&A expense. These procedures also included, among others, testing management's process for determining the recoverable amount of the PP&E in the North America Exploration and Production and Oil Sands Mining and Upgrading segments, and DD&A expense for the North America Exploration and Production and Oil Sands Mining and Upgrading segments. Testing management's process for determining these estimates included (i) evaluating the appropriateness of the methods used by management in making these estimates; (ii) testing the completeness, accuracy and relevance of underlying data used in management's analysis in developing these estimates; (iii) evaluating the significant assumptions used in developing the underlying estimates, including assumptions of expected future rates of production, future commodity pricing, and future development and operating costs; and (iv) testing the unit-of-production rates used to calculate DD&A expense. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the estimates of crude oil and natural gas reserves used to determine DD&A expense and the recoverable amounts of PP&E for the North America Exploration and Production and Oil Sands Mining and Upgrading segments. As a basis for using this work, the specialists' qualifications and objectivity were understood, as well as the methods and assumptions used by the specialists. The procedures performed also included tests of data used by the specialists and an evaluation of their findings. Evaluating the significant assumptions used by management's specialists also involved evaluating whether the assumptions used were reasonable considering the past performance of the Company, consistency with industry pricing forecasts, and whether they were consistent with evidence obtained in other areas of the audit.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada

March 18, 2020

We have served as the Company's auditor since 1973.

Consolidated Balance Sheets

As at December 31

(millions of Canadian dollars)	Note	2019	2018
ASSETS			
Current assets			
Cash and cash equivalents		**$ 139**	$ 101
Accounts receivable		**2,465**	1,148
Current income taxes receivable		**13**	—
Inventory	5	**1,152**	955
Prepaids and other		**174**	176
Investments	9	**490**	524
Current portion of other long-term assets	10	**54**	116
		4,487	3,020
Exploration and evaluation assets	6	**2,579**	2,637
Property, plant and equipment	7	**68,043**	64,559
Lease assets	8	**1,789**	—
Other long-term assets	10	**1,223**	1,343
		$ 78,121	$ 71,559
LIABILITIES			
Current liabilities			
Accounts payable		**$ 816**	$ 779
Accrued liabilities		**2,611**	2,356
Current income taxes payable		**—**	151
Current portion of long-term debt	11	**2,391**	1,141
Current portion of other long-term liabilities	8, 12	**819**	335
		6,637	4,762
Long-term debt	11	**18,591**	19,482
Other long-term liabilities	8, 12	**7,363**	3,890
Deferred income taxes	13	**10,539**	11,451
		43,130	39,585
SHAREHOLDERS' EQUITY			
Share capital	14	**9,533**	9,323
Retained earnings		**25,424**	22,529
Accumulated other comprehensive income	15	**34**	122
		34,991	31,974
		$ 78,121	$ 71,559

Commitments and contingencies (note 20).

Approved by the Board of Directors on March 18, 2020

CATHERINE M. BEST
Chair of the Audit Committee
and Director

N. MURRAY EDWARDS
Executive Chairman of the Board
of Directors and Director

Consolidated Statements of Earnings

For the years ended December 31

(millions of Canadian dollars, except per common share amounts)	Note		2019		2018		2017 [1]
Product sales	22	**$**	**24,394**	$	22,282	$	18,360
Less: royalties			**(1,523)**		(1,255)		(1,018)
Revenue			**22,871**		21,027		17,342
Expenses							
Production			**6,277**		6,464		5,675
Transportation, blending and feedstock			**4,699**		4,189		3,529
Depletion, depreciation and amortization	7, 8		**5,546**		5,161		5,186
Administration			**344**		325		319
Share-based compensation	12		**223**		(146)		134
Asset retirement obligation accretion	12		**190**		186		164
Interest and other financing expense	18		**836**		739		631
Risk management activities	19		**77**		(134)		35
Foreign exchange (gain) loss			**(570)**		827		(787)
Gain on acquisition, disposition and revaluation of properties	6, 7		**—**		(452)		(379)
Loss (gain) from investments	9, 10		**293**		346		(38)
			17,915		17,505		14,469
Earnings before taxes			**4,956**		3,522		2,873
Current income tax expense (recovery)	13		**434**		374		(164)
Deferred income tax (recovery) expense	13		**(894)**		557		640
Net earnings		**$**	**5,416**	$	2,591	$	2,397
Net earnings per common share							
Basic	17	**$**	**4.55**	$	2.13	$	2.04
Diluted	17	**$**	**4.54**	$	2.12	$	2.03

(1) In connection with adoption of IFRS 15 on January 1, 2018, the Company has reclassified certain comparative amounts in a manner consistent with the presentation adopted for the year ended December 31, 2018.

Consolidated Statements of Comprehensive Income

For the years ended December 31

(millions of Canadian dollars)		2019		2018		2017
Net earnings	**$**	**5,416**	$	2,591	$	2,397
Items that may be reclassified subsequently to net earnings						
Net change in derivative financial instruments designated as cash flow hedges						
Unrealized income, net of taxes of $13 million (2018 – $nil, 2017 – $9 million)		**99**		5		53
Reclassification to net earnings, net of taxes of $5 million (2018 – $6 million, 2017 – $5 million)		**(41)**		(39)		(33)
		58		(34)		20
Foreign currency translation adjustment						
Translation of net investment		**(146)**		224		(158)
Other comprehensive income (loss), net of taxes		**(88)**		190		(138)
Comprehensive income	**$**	**5,328**	$	2,781	$	2,259

Consolidated Statements of Changes in Equity

For the years ended December 31 (millions of Canadian dollars)	Note	2019	2018	2017
Share capital	14			
Balance – beginning of year		**$ 9,323**	$ 9,109	$ 4,671
Issued upon exercise of stock options		**360**	332	466
Previously recognized liability on stock options exercised for common shares		**53**	120	154
Purchase of common shares under Normal Course Issuer Bid		**(203)**	(238)	—
Issued for the acquisition of AOSP and other assets [1]	7	**—**	—	3,818
Balance – end of year		**9,533**	9,323	9,109
Retained earnings				
Balance – beginning of year		**22,529**	22,612	21,526
Net earnings		**5,416**	2,591	2,397
Dividends on common shares	14	**(1,783)**	(1,630)	(1,311)
Purchase of common shares under Normal Course Issuer Bid	14	**(738)**	(1,044)	—
Balance – end of year		**25,424**	22,529	22,612
Accumulated other comprehensive income (loss)	15			
Balance – beginning of year		**122**	(68)	70
Other comprehensive income (loss), net of taxes		**(88)**	190	(138)
Balance – end of year		**34**	122	(68)
Shareholders' equity		**$ 34,991**	$ 31,974	$ 31,653

(1) During 2017, in connection with the acquisition of direct and indirect interests in the Athabasca Oil Sands Project ("AOSP") and other assets, the Company issued non-cash share consideration of $3,818 million (see note 7).

Consolidated Statements of Cash Flows

For the years ended December 31 (millions of Canadian dollars)	Note	2019	2018	2017
Operating activities				
Net earnings		**$ 5,416**	$ 2,591	$ 2,397
Non-cash items				
Depletion, depreciation and amortization		**5,546**	5,161	5,186
Share-based compensation		**223**	(146)	134
Asset retirement obligation accretion		**190**	186	164
Unrealized risk management loss (gain)		**13**	(35)	37
Unrealized foreign exchange (gain) loss		**(548)**	706	(821)
Realized foreign exchange loss on repayment of US dollar securities		**—**	146	—
Gain on acquisition, disposition and revaluation of properties		**—**	(452)	(379)
Loss (gain) from investments		**321**	374	(11)
Deferred income tax (recovery) expense		**(894)**	557	640
Other		**(109)**	(23)	(110)
Abandonment expenditures		**(296)**	(290)	(274)
Net change in non-cash working capital	21	**(1,033)**	1,346	299
Cash flows from operating activities		**8,829**	10,121	7,262
Financing activities				
Issue (repayment) of bank credit facilities and commercial paper, net	11, 21	**2,025**	(1,595)	2,222
(Repayment) issue of medium-term notes	11, 21	**(1,000)**	—	1,791
(Repayment) issue of US dollar debt securities	11, 21	**—**	(1,236)	2,733
Payment of lease liabilities	8	**(237)**	—	—
Issue of common shares on exercise of stock options		**360**	332	466
Dividends on common shares		**(1,743)**	(1,562)	(1,252)
Purchase of common shares under Normal Course Issuer Bid		**(941)**	(1,282)	—
Cash flows (used in) from financing activities		**(1,536)**	(5,343)	5,960
Investing activities				
Net expenditures on exploration and evaluation assets	21	**(73)**	(266)	(124)
Net expenditures on property, plant and equipment		**(3,535)**	(4,175)	(4,574)
Acquisition of Devon assets (1)	7	**(3,412)**	—	—
Acquisition of AOSP and other assets, net of cash acquired (2)	7	**—**	—	(8,630)
Investment in other long-term assets		**—**	(28)	(87)
Net change in non-cash working capital	21	**(235)**	(345)	313
Cash flows used in investing activities		**(7,255)**	(4,814)	(13,102)
Increase (decrease) in cash and cash equivalents		**38**	(36)	120
Cash and cash equivalents – beginning of year		**101**	137	17
Cash and cash equivalents – end of year		**$ 139**	$ 101	$ 137
Interest paid on long-term debt, net		**$ 865**	$ 911	$ 725
Income taxes paid (received)		**$ 445**	$ (225)	$ (792)

(1) The acquisition of assets from Devon Canada Corporation ("Devon") in 2019 includes net working capital and other long-term assets of $195 million (see note 7).
(2) The acquisition of AOSP in 2017 includes net working capital of $291 million and excludes non-cash share consideration of $3,818 million (see note 7).

(tabular amounts in millions of Canadian dollars, unless otherwise stated)

1. Accounting Policies

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire and South Africa in Offshore Africa.

The "Oil Sands Mining and Upgrading" segment produces synthetic crude oil through bitumen mining and upgrading operations at Horizon Oil Sands ("Horizon") and through the Company's direct and indirect interest in AOSP.

Within Western Canada, in the "Midstream and Refining" segment, the Company maintains certain activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("Redwater Partnership"), a general partnership formed to upgrade and refine bitumen in the Province of Alberta.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2100, 855 - 2 Street S.W., Calgary, Alberta, Canada.

The Company's consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The accounting policies adopted by the Company under IFRS are set out below. The Company has consistently applied the same accounting policies throughout all periods presented, except where IFRS permits new accounting standards to be adopted prospectively. Changes in the Company's accounting policies are discussed in note 2.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements have been prepared under the historical cost basis, unless otherwise required.

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and wholly owned partnerships. Subsidiaries include all entities over which the Company has control. Subsidiaries are consolidated from the date on which the Company obtains control. They are deconsolidated from the date that control ceases.

Certain of the Company's activities are conducted through joint arrangements in which two or more parties have joint control. Where the Company has determined that it has a direct ownership interest in jointly controlled assets and obligations for the liabilities (a "joint operation"), the assets, liabilities, revenue and expenses related to the joint operation are included in the consolidated financial statements in proportion to the Company's interest. Where the Company has determined that it has an interest in jointly controlled entities (a "joint venture"), it uses the equity method of accounting. Under the equity method, the Company's initial and subsequent investments are recognized at cost and subsequently adjusted for the Company's share of the joint venture's income or loss, less distributions received. If the Company's share of the joint venture's loss equals or exceeds its interest in the joint venture, the Company discontinues recognizing its share of further losses. The Company resumes recognizing profits when its share of profits exceeds the accumulated share of losses not recognized.

Joint ventures accounted for using the equity method of accounting are tested for impairment whenever objective evidence indicates that the carrying amount of the investment may not be recoverable. Indications of impairment include a history of losses, significant capital expenditure overruns, liquidity concerns, financial restructuring of the investee or significant adverse changes in the technological, economic or legal environment. The amount of the impairment is measured as the difference between the carrying amount of the investment and the higher of its fair value less costs of disposal and its value in use. Impairment losses are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

(B) SEGMENTED INFORMATION

Operating segments have been determined based on the nature of the Company's activities and the geographic locations in which the Company operates, and are consistent with the level of information regularly provided to and reviewed by the Company's chief operating decision makers.

(C) CASH AND CASH EQUIVALENTS

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with an original term to maturity at purchase of three months or less are reported as cash equivalents in the consolidated balance sheets.

(D) INVENTORY

Inventory is primarily comprised of product inventory and materials and supplies and is carried at the lower of cost and net realizable value. Product inventory is comprised of crude oil held for sale, including pipeline linefill and crude oil stored in floating production, storage and offloading vessels ("FPSO"). Cost of product inventory consists of purchase costs, direct production costs, directly attributable overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Net realizable value for product inventory is determined by reference to forward prices. Cost for materials and supplies consists of purchase costs and is based on a first-in, first-out or an average cost basis. Net realizable value for materials and supplies is determined by reference to current market prices.

(E) EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation ("E&E") assets consist of the Company's crude oil and natural gas exploration projects that are pending the determination of proved reserves.

E&E costs are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area. These costs are recognized in net earnings.

Once the technical feasibility and commercial viability of E&E assets are determined and a development decision is made by management, the E&E assets are tested for impairment upon reclassification to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. An E&E asset is derecognized upon disposal or when no future economic benefits are expected to arise from its use. Any gain or loss arising on derecognition of the asset is recognized in net earnings within depletion, depreciation and amortization.

E&E assets are also tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of the related Cash Generating Units ("CGUs"), aggregated at a segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks.

(F) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Assets under construction are not depleted or depreciated until available for their intended use.

Exploration and Production

The cost of an asset comprises its acquisition costs, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs. Property acquisition costs are comprised of the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

When significant components of an item of property, plant and equipment, including crude oil and natural gas interests, have different useful lives, they are accounted for separately.

Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves, except for certain major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves.

Oil Sands Mining and Upgrading

Capitalized costs for the Oil Sands Mining and Upgrading segment are reported separately from the Company's North America Exploration and Production segment. Capitalized costs include acquisition costs, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs.

Mine-related costs are depleted using the unit-of-production method based on proved reserves. Costs of the upgraders and related infrastructure located on the Horizon and AOSP sites are depreciated on the unit-of-production method based on the estimated productive capacity of the respective upgraders and related infrastructure. Other equipment is depreciated on a straight-line basis over its estimated useful life ranging from 2 to 18 years.

Midstream, Refining and Head Office

The Company capitalizes all costs that expand the capacity or extend the useful life of the midstream, refining and head office assets. Midstream and Refining assets are depreciated on a straight-line basis over their estimated useful lives ranging from 5 to 30 years. Head office assets are depreciated on a declining balance basis.

Useful lives

The depletion rates and expected useful lives of property, plant and equipment are reviewed on an annual basis, with changes in depletion rates and useful lives accounted for prospectively.

Derecognition

A property, plant and equipment asset is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is recognized in net earnings within depletion, depreciation and amortization.

Major maintenance expenditures

Inspection costs associated with major maintenance turnarounds are capitalized and depreciated over the period to the next major maintenance turnaround. Maintenance costs are expensed as incurred.

Impairment

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs an impairment test related to the assets. Individual assets are grouped for impairment assessment purposes into CGUs, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount through depletion, depreciation and amortization expense.

In subsequent periods, an assessment is made at each reporting date to determine whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is re-estimated and the net carrying amount of the asset is increased to its revised recoverable amount. The revised recoverable amount cannot exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, had no impairment loss been recognized for the asset in prior periods. A reversal of impairment is recognized in net earnings. After a reversal, the depletion, depreciation and amortization charge is adjusted in future periods to allocate the asset’s revised carrying amount over its remaining useful life.

(G) BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed in a business combination are recognized at their fair value at the date of the acquisition. Any excess of the consideration paid over the fair value of the net assets acquired is recognized as an asset. Any excess of the fair value of the net assets acquired over the consideration paid is recognized in net earnings.

(H) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during the initial development of a mine at Horizon and AOSP are capitalized to property, plant and equipment. Overburden removal costs incurred during the production of a mine are included in the cost of inventory, unless the overburden removal activity has resulted in a probable inflow of future economic benefits to the Company, in which case the costs are capitalized to property, plant and equipment. Capitalized overburden removal costs are depleted over the life of the mining reserves that directly benefit from the overburden removal activity.

(I) CAPITALIZED BORROWING COSTS

Borrowing costs attributable to the acquisition, construction or production of qualifying assets are capitalized to the cost of those assets until such time as the assets are substantially available for their intended use. Qualifying assets are comprised of those significant assets that require a period greater than one year to be available for their intended use. All other borrowing costs are recognized in net earnings.

(J) LEASES

At inception of a contract, the Company assesses whether a contract is, or contains a lease. A contract is, or contains a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, the Company assesses whether: the contract involves the use of an identified asset; the Company has the right to obtain substantially all of the economic benefits from the use of the asset throughout the period of use; and, the Company has the right to direct the use of the asset.

The Company recognizes a lease asset and a lease liability at the commencement date of the lease contract, which is the date that the lease asset is available to the Company. The lease asset is initially measured at cost. The cost of a lease asset includes the amount of the initial measurement of the lease liability, lease payments made prior to the commencement date, initial direct costs and estimates of the asset retirement obligation, if any. Subsequent to initial recognition, the lease asset is depreciated using the straight-line method over the earlier of the end of the useful life of the lease asset or the lease term.

Lease liabilities are initially measured at the present value of lease payments discounted at the rate implicit in the lease, or if not readily determinable, the Company's incremental borrowing rate. Lease payments include fixed lease payments, variable lease payments based on indices or rates, residual value guarantees, and purchase options expected to be exercised. Subsequent to initial recognition, the lease liability is measured at amortized cost using the effective interest method. Lease liabilities are remeasured if there are changes in the lease term or if the Company changes its assessment of whether it is reasonably certain it will exercise a purchase, extension or termination option. Lease liabilities are also remeasured if there are changes in the estimate of the amounts payable under the lease due to changes in indices or rates, or residual value guarantees.

Lease assets are reported in a separate caption in the consolidated balance sheet. Lease liabilities are reported within other long-term liabilities in the consolidated balance sheet.

Depreciation on lease assets used in the construction of property, plant and equipment is capitalized to the cost of those assets over their period of use until such time as the property, plant and equipment is substantially available for its intended use.

Where the Company acts as the operator of a joint operation, the Company recognizes 100% of the related lease asset and lease liability. As the Company recovers its joint operation partners' share of the costs of the lease contract, these recoveries are recognized as other income in the consolidated statements of earnings.

On January 1, 2019 the Company adopted IFRS 16 "Leases" (see note 2) and as permitted in the transition requirements of the standard, the Company continues to account for leases for the years ended December 31, 2018 and 2017 in accordance with the Company's previous accounting policy for leases as follows:

Finance leases, which transfer substantially all of the risks and rewards incidental to ownership of the leased item to the Company, are capitalized at the commencement of the lease term at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term. Operating lease payments are recognized in net earnings over the lease term.

(K) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on all of its property, plant and equipment and certain exploration and evaluation assets based on current legislation and industry operating practices. Provisions for asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Provisions are measured at the present value of management’s best estimate of expenditures required to settle the obligation as at the date of the balance sheets. Subsequent to the initial measurement, the obligation is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes due to discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Actual costs incurred upon settlement of the asset retirement obligation are charged against the provision.

(L) FOREIGN CURRENCY TRANSLATION

Functional and presentation currency

Items included in the financial statements of the Company’s subsidiary companies and partnerships are measured using the currency of the primary economic environment in which the subsidiary operates (the "functional currency"). The consolidated financial statements are presented in Canadian dollars, which is the Company’s functional currency.

The assets and liabilities of subsidiaries that have a functional currency different from that of the Company are translated into Canadian dollars at the closing rate at the date of the balance sheets, and revenue and expenses are translated at the average rate for the period. Cumulative foreign currency translation adjustments are recognized in other comprehensive income.

When the Company disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in other comprehensive income related to the foreign operation are recognized in net earnings.

Transactions and balances

Foreign currency transactions are translated into the functional currency of the Company and its subsidiaries and partnerships using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at balance sheet date exchange rates of monetary assets and liabilities denominated in currencies other than the functional currency are recognized in net earnings.

(M) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the sale of crude oil and NGLs and natural gas products is recognized when performance obligations in the sales contract are satisfied and it is probable that the Company will collect the consideration to which it is entitled. Performance obligations are generally satisfied at the point in time when the product is delivered to a location specified in a contract and control passes to the customer. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Contracts for sale of the Company's products generally have terms of less than a year, with certain contracts extending beyond one year. Contracts in North America generally specify delivery of crude oil and NGLs and natural gas throughout the term of the contract. Contracts in the North Sea and Offshore Africa generally specify delivery of crude oil at a point in time.

Sales of the Company's crude oil and NGLs and natural gas products to customers are made pursuant to contracts based on prevailing commodity pricing at or near the time of delivery and volumes of product delivered. Revenues are typically collected in the month following delivery and accordingly, the Company has elected to apply the practical expedient to not adjust consideration for the effects of a financing component. Purchases and sales of crude oil and NGLs and natural gas with the same counterparty, made to facilitate sales to customers or potential customers, that are entered into in contemplation of one another, are combined and recorded as non-monetary exchanges and measured at the net settlement amount.

Revenue in the consolidated statement of earnings represents the Company's share of product sales net of royalty payments to governments and other mineral interest owners. The Company discloses the disaggregation of revenues from sales of crude oil and NGLs and natural gas in the segmented information in note 22. Related costs of goods sold are comprised of production, transportation, blending and feedstock, and depletion, depreciation and amortization expenses. These amounts have been separately presented in the consolidated statements of earnings.

On January 1, 2018 the Company adopted IFRS 15 "Revenue from Contracts with Customers" and as permitted in the transition requirements of the standard, the Company continues to report revenue for the year ended December 31, 2017 in accordance with the Company's previous accounting policy for revenue and cost of goods sold as follows:

Revenue from the sale of crude oil and natural gas is recognized when title passes to the customer, delivery has taken place and collection is reasonably assured. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

(N) PRODUCTION SHARING CONTRACTS

Production generated from Côte d'Ivoire and Gabon in Offshore Africa is shared under the terms of various Production Sharing Contracts ("PSCs"). Product sales are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the respective government state oil companies (the "Governments"). Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Governments. The Governments' share of profit oil attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the terms of the respective PSCs.

(O) INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases.

Deferred income tax assets and liabilities are calculated using the substantively enacted income tax rates that are expected to apply when the asset or liability is recovered. Deferred income tax assets or liabilities are not recognized when they arise on the initial recognition of an asset or liability in a transaction (other than in a business combination) that, at the time of the transaction, affects neither accounting nor taxable profit. Deferred income tax assets or liabilities are also not recognized on possible future distributions of retained earnings of subsidiaries where the timing of the distribution can be controlled by the Company and it is probable that a distribution will not be made in the foreseeable future, or when distributions can be made without incurring income taxes.

Deferred income tax assets for deductible temporary differences and tax loss carryforwards are recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized. The carrying amount of deferred income tax assets is reviewed at each reporting date, and is reduced if it is no longer probable that sufficient future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized.

Current income tax is calculated based on net earnings for the period, adjusted for items that are non-taxable or taxed in different periods, using income tax rates that are substantively enacted at each reporting date.

Income taxes are recognized in net earnings or other comprehensive income, consistent with the items to which they relate.

(P) SHARE-BASED COMPENSATION

The Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The liability for awards granted to employees is initially measured based on the grant date fair value of the awards and the number of awards expected to vest. The awards are re-measured each reporting period for subsequent changes in the fair value of the liability. Fair value is determined using the Black-Scholes valuation model under a graded vesting method. Expected volatility is estimated based on historic results. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by the employee and any previously recognized liability associated with the stock options are recorded as share capital.

The Performance Share Unit ("PSU") plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met. PSUs vest three years from original grant date. The liability for PSUs is initially measured in reference to the Company's stock price and the number of awards expected to vest and is re-measured at each reporting period for changes in the fair value of the liability.

The unamortized costs of employer contributions to the Company's share bonus program are included in other long-term assets.

(Q) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: financial assets at amortized cost; financial liabilities at amortized cost; and fair value through profit or loss. All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Fair value through profit or loss financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash and cash equivalents, accounts receivable and certain other long-term assets are classified as financial assets at amortized cost since it is the Company's intention to hold these assets to maturity and the related cash flows are solely comprised of payments of principal and interest. Investments in publicly traded shares are classified as fair value through profit or loss. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as financial liabilities at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

Financial assets and liabilities are also categorized using a three-level hierarchy that reflects the significance of the inputs used in making fair value measurements for these assets and liabilities. The fair values of financial assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of financial assets and liabilities in Level 2 are based on inputs other than Level 1 quoted prices that are observable for the asset or liability either directly (as prices) or indirectly (derived from prices). The fair values of Level 3 financial assets and liabilities are not based on observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability.

Transaction costs in respect of financial instruments at fair value through profit or loss are recognized in net earnings. Transaction costs in respect of other financial instruments are included in the initial measurement of the financial instrument.

Impairment of financial assets

At each reporting date, on a forward looking basis, the Company assesses the expected credit losses associated with its financial assets carried at amortized cost. Expected credit losses are measured as the difference between the cash flows that are due to the Company and the cash flows that the Company expects to receive, discounted at the effective interest rate determined at initial recognition. For trade accounts receivable, the Company applies the simplified approach permitted by IFRS 9, which requires expected lifetime credit losses to be recognized from initial recognition of the receivables. To measure expected credit losses, accounts receivable are grouped based on the number of days the receivables have been outstanding and internal credit assessments of the customers. Credit risk for longer-term receivables is assessed based on an external credit rating of the counterparty. For longer-term receivables with credit risk that has not increased significantly since the date of recognition, the Company measures the expected credit loss as the 12-month expected credit loss.

Changes in the provision for expected credit loss are recognized in net earnings.

On January 1, 2018 the Company adopted IFRS 9 "Financial Instruments" and as permitted in the transition requirements of the standard, the Company continues to report impairment of financial assets for the year ended December 31, 2017 in accordance with the Company's previous accounting policy for impairment of financial assets as follows:

At each reporting date, the Company assesses whether there is objective evidence that a financial asset is impaired. If such evidence exists, an impairment loss is recognized. Impairment losses on financial assets carried at amortized cost are calculated as the difference between the amortized cost of the financial asset and the present value of the estimated future cash flows, discounted using the instrument's original effective interest rate. Impairment losses on financial assets carried at amortized cost are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

(R) RISK MANAGEMENT ACTIVITIES

The Company periodically uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The carrying amount of a risk management liability is adjusted for the Company's own credit risk.

The Company documents all derivative financial instruments that are formally designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company periodically enters into commodity price contracts to manage anticipated sales and purchases of crude oil and natural gas in order to protect its cash flow for its capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts formally designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in net earnings in the same period or periods in which the commodity is sold or purchased. The ineffective portion of changes in the fair value of these designated contracts is recognized in risk management activities in net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in net earnings.

The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on certain of its long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are recognized in interest expense in net earnings. Changes in the fair value of non-designated interest rate swap contracts are recognized in risk management activities in net earnings.

Upon termination of an interest rate swap designated as a fair value hedge, the interest rate swap is derecognized in the consolidated balance sheets and the related long-term debt hedged is no longer revalued for subsequent changes in fair value due to interest rates changes. The fair value adjustment due to interest rates on the long-term debt at the date of termination of the interest rate swap is amortized to interest expense over the remaining term of the long-term debt.

Cross currency swap contracts are periodically used to manage currency exposure on US dollar denominated long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges related to the notional principal amounts are recognized in foreign exchange gains and losses in net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to interest expense when the hedged item is recognized in net earnings, with the ineffective portion recognized in risk management activities in net earnings. Changes in the fair value of non-designated cross currency swap contracts are recognized in risk management activities in net earnings.

Realized gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income and amortized into net earnings in the periods in which the underlying hedged items are recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized in net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in net earnings.

Foreign currency forward contracts are periodically used to manage foreign currency cash requirements. The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of foreign currency forward contracts designated as cash flow hedges are initially recorded in other comprehensive income and are reclassified to foreign exchange gains and losses when the hedged item is recognized in net earnings. Changes in the fair value of non-designated foreign currency forward contracts are recognized in risk management activities in net earnings.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not clearly and closely related to the host contract, except when the host contract is an asset.

(S) COMPREHENSIVE INCOME

Comprehensive income is comprised of the Company's net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses arising from the net investment in foreign operations that do not have a Canadian dollar functional currency. Other comprehensive income is shown net of related income taxes.

(T) PER COMMON SHARE AMOUNTS

The Company calculates basic earnings per common share by dividing net earnings by the weighted average number of common shares outstanding during the period. As the Company's Option Plan allows for the settlement of stock options in either cash or shares at the option of the holder, diluted earnings per common share is calculated using the more dilutive of cash settlement or share settlement under the treasury stock method.

(U) SHARE CAPITAL

Common shares are classified as equity. Costs directly attributable to the issue of new shares or options are included in equity as a deduction from proceeds, net of tax. When the Company acquires its own common shares, share capital is reduced by the average carrying value of the shares purchased. The excess of the purchase price over the average carrying value is recognized as a reduction of retained earnings. Shares are cancelled upon purchase.

(V) DIVIDENDS

Dividends on common shares are recognized in the Company's financial statements in the period in which the dividends are declared by the Board of Directors.

2. Changes in Accounting Policies

IFRS 16 "LEASES"

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaced IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and generally requires balance sheet recognition for all leases. Certain short-term (12 months or less) and low-value leases are exempt from the requirements, and the Company continues to treat these leases as expenses. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are also exempt from the standard.

The Company adopted IFRS 16 on January 1, 2019 using the modified retrospective approach with no impact to opening retained earnings at the date of adoption. In accordance with the transitional provisions in the standard, balances reported in the comparative periods have not been restated and continue to be reported using the Company's previous accounting policy under IAS 17.

On adoption, the Company applied the following practical expedients under the standard. Certain expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- leases with a remaining lease term of twelve months or less as at January 1, 2019 were treated as short-term leases;
- exclusion of initial direct costs for the measurement of lease assets at the date of initial application; and
- the application of the Company's previous assessment for onerous contracts under IAS 37, instead of re-assessing impairment on the Company's lease assets as at January 1, 2019.

The Company did not apply any practical expedients pertaining to grandfathering of leases assessed under the previous standard.

In connection with the adoption of IFRS 16, the Company recognized lease liabilities (included in other long-term liabilities) of $1,539 million, measured at the present value of the remaining lease payments, discounted at the Company's incremental borrowing rate at the transition date. Lease assets were measured at an amount equal to the lease liability. The adoption of IFRS 16 resulted in increases in depletion, depreciation and amortization expense and interest expense and corresponding decreases in production, transportation and administration expenses. Under the new standard, the Company reports cash outflows for payment of the principal portion of the lease liability as cash flows used in financing activities. The interest portion of the lease payments is classified as cash flows from operating activities.

Further details of the Company's lease assets and lease liabilities on transition to the new Leases standard at January 1, 2019 and as at December 31, 2019 are shown in note 8.

CHANGES IN OTHER ACCOUNTING POLICIES

In October 2017, the IASB issued amendments to IAS 28 "Investments in Associates and Joint Ventures" to clarify that the impairment provisions in IFRS 9 apply to financial instruments in an associate or joint venture that are not accounted for using the equity method, including long-term assets that form part of the net investment in the associate or the joint venture. The Company retrospectively adopted the amendments on January 1, 2019. These amendments did not have a significant impact on the Company's consolidated financial statements.

In June 2017, the IASB issued IFRIC 23 "Uncertainty over Income Tax Treatments". The interpretation provides guidance on how to reflect the effects of uncertainty in accounting for income taxes where IAS 12 is unclear. The Company adopted the interpretation on January 1, 2019. The interpretation did not have a significant impact on the Company's consolidated financial statements.

3. Accounting Standards Issued But Not Yet Applied

In October 2018, the IASB issued amendments to IFRS 3 "Definition of a Business" that narrowed and clarified the definition of a business. The amendments permit a simplified assessment of whether an acquired set of activities and assets is a group of assets rather than a business. The amendments are effective January 1, 2020 with earlier adoption permitted. The amendments apply to business combinations after the date of adoption. The Company prospectively adopted the amendments on January 1, 2020.

In October 2018, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" and IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors". The amendments make minor changes to the definition of the term "material" and align the definition across all IFRS Standards. Materiality is used in making judgments related to the preparation of financial statements. The amendments are effective January 1, 2020 with earlier adoption permitted. The Company prospectively adopted the amendments on January 1, 2020.

4. Critical Accounting Estimates and Judgements

The Company has made estimates, assumptions and judgements regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements, primarily related to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts. The estimates, assumptions and judgements that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

(A) CRUDE OIL AND NATURAL GAS RESERVES

Purchase price allocations, depletion, depreciation and amortization, asset retirement obligations, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserves estimates are based on engineering data, estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations and judgements. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information.

(B) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on its property, plant and equipment based on current legislation and operating practices. Estimated future costs include assumptions of dates of future abandonment and technological advances and estimates of future inflation rates and discount rates. Actual costs may vary from the estimated provision due to changes in environmental legislation, the impact of inflation, changes in technology, changes in operating practices, and changes in the date of abandonment due to changes in reserves life. These differences may have a material impact on the estimated provision.

(C) INCOME TAXES

The Company is subject to income taxes in numerous legal jurisdictions. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

(D) FAIR VALUE OF DERIVATIVES AND OTHER FINANCIAL INSTRUMENTS

The fair value of financial instruments that are not traded in an active market is determined using valuation techniques. The Company uses its judgement to select a variety of methods and make assumptions that are primarily based on market conditions existing at the end of each reporting period. The Company uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates.

(E) PURCHASE PRICE ALLOCATIONS

Purchase prices related to business combinations are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation, and amortization expense and impairment tests.

(F) SHARE-BASED COMPENSATION

The Company has made various assumptions in estimating the fair values of stock options granted under its Option Plan, including expected volatility, expected exercise timing and future forfeiture rates. At each period end, stock options outstanding are remeasured for changes in the estimated fair value of the liability.

(G) IDENTIFICATION OF CGUs

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGUs requires significant judgement and interpretations with respect to the integration between assets, the existence of active markets, shared infrastructures, and the way in which management monitors the Company's operations.

(H) IMPAIRMENT OF ASSETS

The recoverable amount of a CGU or an individual asset has been determined as the higher of the CGUs' or the asset's fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available, including information on future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and operating costs, after-tax discount rates currently ranging from 10% to 12%, and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

(I) LEASES

Purchase, extension and termination options are included in certain of the Company's leases to provide operational flexibility. To measure the lease liability, the Company uses judgment to assess the likelihood of exercising these options. These assessments are reviewed when significant events or circumstances indicate that the likelihood of exercising these options may have changed. The Company also uses estimates to determine its incremental borrowing costs if the interest rate implicit in the lease is not readily determinable.

(J) CONTINGENCIES

Contingencies are subject to measurement uncertainty as the related financial impact will only be confirmed by the outcome of a future event. The assessment of contingencies requires the application of judgements and estimates including the determination of whether a present obligation exists and the reliable estimation of the timing and amount of cash flows required to settle the contingency.

5. Inventory

		2019		2018
Product inventory	**$**	**468**	$	297
Materials and supplies		**684**		658
	$	**1,152**	$	955

The Company recorded a write-down of its product inventory of $4 million from cost to net realizable value as at December 31, 2019 (2018 – $13 million).

6. Exploration and Evaluation Assets

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2017	$ 2,282	$ —	$ 91	$ 259	$ 2,632
Additions	245	—	35	222	502
Transfers to property, plant and equipment	(175)	—	—	(222)	(397)
Disposals/derecognitions and other	(4)	—	(89)	(7)	(100)
At December 31, 2018	2,348	—	37	252	2,637
Additions	**38**	**—**	**33**	**—**	**71**
Acquisition of Devon assets (note 7)	**91**	**—**	**—**	**—**	**91**
Transfers to property, plant and equipment	**(219)**	**—**	**—**	**—**	**(219)**
Foreign exchange adjustments	**—**	**—**	**(1)**	**—**	**(1)**
At December 31, 2019	**$ 2,258**	**$ —**	**$ 69**	**$ 252**	**$ 2,579**

On June 27, 2019, the Company completed the acquisition of substantially all of the assets of Devon including thermal in situ and heavy crude oil assets, for total cash purchase consideration of $3,412 million, including $91 million of exploration and evaluation assets (see note 7).

During 2018, the Company acquired a number of exploration and evaluation properties in the Oil Sands Mining and Upgrading and North America Exploration and Production segments:

In the Oil Sands Mining and Upgrading segment, the Company acquired the Joslyn oil sands project including exploration and evaluation assets of $222 million and associated asset retirement obligations of $4 million. Total consideration of $218 million was comprised of $100 million cash on closing with the remaining balance paid equally over each of the next five years. In the fourth quarter of 2018, following integration of the acquired assets into the Horizon mine plan and determination of proved crude oil reserves, the exploration and evaluation assets were transferred to property, plant and equipment.

In the North America Exploration and Production segment, the Company acquired Laricina Energy Ltd., including exploration and evaluation assets of $118 million and property, plant and equipment of $44 million. In addition, the Company acquired cash of $24 million and deferred income tax assets of $168 million and assumed net working capital liabilities of $18 million, asset retirement obligations of $17 million, and notes payable of $48 million. Total purchase consideration was $46 million, resulting in a pre-tax gain of $225 million on the acquisition, representing the excess of the fair value of the net assets acquired compared to total purchase consideration. The Company settled the notes payable immediately following the completion of the acquisition. The transaction was accounted for using the acquisition method of accounting.

During 2018, the Company also completed two additional farm-out agreements in the Offshore Africa segment to dispose of a combined 30% interest in its exploration right in South Africa, comprised of exploration and evaluation assets of $89 million, including a recovery of $14 million of past incurred costs, for net proceeds of $105 million (US$79 million), resulting in a pre-tax gain of $16 million ($12 million after-tax). The Company retains a 20% working interest in the exploration right following the completion of these farm-out agreements. Under the terms of the various agreements, in the event of a commercial crude oil or natural gas discovery on the exploration right and conversion to a production right, additional cash payments would be made to the Company.

During 2017, the Company also disposed of a number of North America exploration and evaluation assets with a net book value of $1 million for consideration of $36 million, resulting in a pre-tax gain on sale of properties of $35 million.

7. Property, Plant and Equipment

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2017	$ 64,816	$ 7,126	$ 4,881	$ 42,084	$ 428	$ 414	$ 119,749
Additions [1]	2,428	237	212	1,050	13	21	3,961
Transfers from E&E assets	175	—	—	222	—	—	397
Disposals/derecognitions and other	(412)	(703)	(70)	(209)	—	—	(1,394)
Foreign exchange adjustments and other	—	661	448	—	—	—	1,109
At December 31, 2018	67,007	7,321	5,471	43,147	441	435	123,822
Additions	**2,613**	**349**	**233**	**2,154**	**10**	**34**	**5,393**
Acquisition of Devon assets	**3,325**	**—**	**—**	**—**	**—**	**—**	**3,325**
Transfers from E&E assets	**219**	**—**	**—**	**—**	**—**	**—**	**219**
Disposals/derecognitions [2]	**(537)**	**—**	**(1,515)**	**(285)**	**—**	**(3)**	**(2,340)**
Foreign exchange adjustments and other	**—**	**(374)**	**(256)**	**—**	**—**	**—**	**(630)**
At December 31, 2019	**$ 72,627**	**$ 7,296**	**$ 3,933**	**$ 45,016**	**$ 451**	**$ 466**	**$ 129,789**
Accumulated depletion and depreciation							
At December 31, 2017	$ 41,151	$ 5,653	$ 3,719	$ 3,628	$ 124	$ 304	$ 54,579
Expense	3,111	257	201	1,557	14	21	5,161
Disposals/derecognitions	(393)	(703)	(70)	(209)	—	—	(1,375)
Foreign exchange adjustments and other	12	528	353	5	—	—	898
At December 31, 2018	43,881	5,735	4,203	4,981	138	325	59,263
Expense	**3,215**	**256**	**214**	**1,564**	**15**	**23**	**5,287**
Disposals/derecognitions [2]	**(537)**	**—**	**(1,515)**	**(285)**	**—**	**(3)**	**(2,340)**
Foreign exchange adjustments and other	**18**	**(279)**	**(190)**	**(13)**	**—**	**—**	**(464)**
At December 31, 2019	**$ 46,577**	**$ 5,712**	**$ 2,712**	**$ 6,247**	**$ 153**	**$ 345**	**$ 61,746**
Net book value							
– at December 31, 2019	**$ 26,050**	**$ 1,584**	**$ 1,221**	**$ 38,769**	**$ 298**	**$ 121**	**$ 68,043**
– at December 31, 2018	$ 23,126	$ 1,586	$ 1,268	$ 38,166	$ 303	$ 110	$ 64,559

(1) Additions in North Sea during 2018 include a pre-tax revaluation gain of $19 million relating to acquisitions of its previously held interest.
(2) Following demobilization of the FPSO at the Olowi field, Gabon in 2019, the Company derecognized property, plant and equipment and associated accumulated depletion and depreciation of $1,515 million.

Acquisitions in the current and comparative years have been accounted for as business combinations using the acquisition method of accounting. Gains reported on the acquisitions represent the excess of the fair value of the net assets acquired compared to total purchase consideration.

During 2019, the Company acquired a number of producing crude oil and natural gas properties in the North America Exploration and Production segment, excluding the impact of acquisitions disclosed below, for net cash consideration of $80 million (2018 – $170 million; 2017 – $1,013 million including $27 million of exploration and evaluation assets) and assumed associated asset retirement obligations of $20 million (2018 – $13 million; 2017 – $63 million). No net deferred income tax liabilities were recognized (2018 – $nil; 2017 – $nil) and no pre-tax gains were recognized on these net transactions (2018 – pre-tax gain of $47 million; 2017 – $nil).

During 2018, in connection with the acquisition of the remaining interest in certain operations in the North Sea Exploration and Production segment, the Company acquired $108 million of property, plant and equipment, for net proceeds received of $73 million. The Company also acquired net working capital of $7 million, assumed associated asset retirement obligations of $41 million and recognized net deferred income tax liabilities of $27 million. The Company recognized a pre-tax gain of $120 million on the acquisition and a pre-tax revaluation gain of $19 million relating to its previously held interest.

During 2018, the Gabonese Republic agreed to cessation of production from the Company's Olowi field, as well as the terms of termination of the Olowi Production Sharing Contract and the return of the permit area back to the Gabonese Republic, including the associated asset retirement obligations of $69 million. The transaction resulted in a pre-tax gain on disposition of property of $20 million ($14 million after-tax).

In connection with the acquisition of pipeline system assets in the Midstream and Refining segment in 2017, the Company recognized a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in the pipeline.

As at December 31, 2019, the Company assessed the recoverability of its property, plant and equipment and its exploration and evaluation assets, and determined the carrying amounts to be recoverable.

As at December 31, 2019, the Company recognized certain project costs, not subject to depletion and depreciation, of $115 million in the Oil Sands Mining and Upgrading segment (2018 – $1,424 million in the North America Exploration and Production segment). As at December 31, 2018, project costs not subject to depletion and depreciation primarily related to the Kirby North project, which was fully commissioned in 2019.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. During 2019, pre-tax interest of $53 million (2018 – $69 million; 2017 – $82 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 4.0% (2018 – 3.9%; 2017 – 3.8%).

ACQUISITION OF THERMAL IN SITU AND PRIMARY HEAVY CRUDE OIL ASSETS

On June 27, 2019, the Company completed the acquisition of substantially all of the assets of Devon including thermal in situ and heavy crude oil assets, for total cash purchase consideration of $3,412 million, subject to final closing adjustments.

In connection with the acquisition, the Company arranged a new $3,250 million committed term facility (see note 11) and assumed certain product transportation commitments (see note 20).

The acquisition has been accounted for as a business combination using the acquisition method of accounting. The allocation of the purchase price was based on management's best estimates of the fair value of the assets and liabilities acquired as at the acquisition date. Key assumptions used in the determination of estimated fair value were future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and operating costs, discount rates, and income taxes.

The following provides a summary of the net assets acquired relating to the acquisition:

Property, plant and equipment	**$**	**3,325**
Exploration and evaluation assets		**91**
Inventory, prepaids and other long-term assets		**195**
Accrued liabilities		**(21)**
Asset retirement obligations		**(178)**
Net assets acquired	**$**	**3,412**

The above amounts are estimates, and may be subject to change based on the receipt of new information.

As a result of the acquisition, revenue increased by approximately $1,540 million to $22,871 million and revenue, less production and transportation, blending and feedstock expenses increased by approximately $590 million to $11,895 million for the year ended December 31, 2019.

If the acquisition had been completed on January 1, 2019, the Company estimates that pro forma revenue, net of blending costs would have increased by an additional $1,010 million and pro forma revenue, net of blending costs, less production and transportation and feedstock expenses would have increased by an additional $670 million for the year ended December 31, 2019. Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have resulted had the acquisition actually occurred on January 1, 2019, or of future results. Pro forma results are based on available historical information for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition date.

ACQUISITION OF INTERESTS IN THE ATHABASCA OIL SANDS PROJECT AND OTHER ASSETS

On May 31, 2017, the Company completed the acquisition of a direct and indirect 70% interest in AOSP from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), including a 70% interest in the mining and extraction operations north of Fort McMurray, Alberta, 70% of the Scotford Upgrader and Quest Carbon Capture and Storage ("CCS") project, and a 100% working interest in the Peace River thermal in situ operations and Cliffdale heavy oil field, as well as other oil sands leases. The Company also assumed certain pipeline and other commitments (see note 20). The Company consolidates its direct and indirect interest in the assets, liabilities, revenue and expenses of AOSP and other assets in proportion to the Company's interests.

Total purchase consideration of $12,541 million was comprised of cash payments of $8,217 million, approximately 97.6 million common shares of the Company issued to Shell with a fair value of approximately $3,818 million, and deferred purchase consideration of $506 million (US$375 million) paid to Marathon in March 2018. The fair value of the Company's common shares was determined using the market price of the shares as at the acquisition date.

The acquisition has been accounted for as a business combination using the acquisition method of accounting. The allocation of the purchase price was based on management's best estimates of the fair value of the assets and liabilities acquired as at the acquisition date. For the year ended December 31, 2017, the Company recognized a gain of $230 million, net of transaction costs of $3 million, representing the excess of the fair value of the net assets acquired compared to total purchase consideration.

8. Leases

LEASE ASSETS

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At January 1, 2019 (1)	$ 823	$ 332	$ 252	$ 132	$ 1,539
Additions	**452**	**43**	**12**	**20**	**527**
Depreciation	**(106)**	**(54)**	**(72)**	**(27)**	**(259)**
Derecognitions	**—**	**(6)**	**—**	**—**	**(6)**
Foreign exchange adjustments and other	**(3)**	**2**	**(10)**	**(1)**	**(12)**
At December 31, 2019	**$ 1,166**	**$ 317**	**$ 182**	**$ 124**	**$ 1,789**

(1) The Company adopted IFRS 16 "Leases" on January 1, 2019 using the modified retrospective approach. At December 31, 2018, the Company did not report any finance leases in accordance with its previous accounting policy for leases.

LEASE ASSETS, BY SEGMENT

	Dec 31, 2019
Exploration and Production	
North America	**$ 300**
North Sea	**38**
Offshore Africa	**154**
Oil Sands Mining and Upgrading	**1,191**
Head office	**106**
	$ 1,789

LEASE LIABILITIES

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities at December 31, 2019 were as follows:

		Dec 31, 2019
Lease liabilities	$	1,809
Less: current portion		233
	$	1,576

In addition to the lease assets disclosed above, on an ongoing basis the Company enters into short-term leases related to its Exploration and Production and Oil Sands Mining and Upgrading activities.

Other amounts included in net earnings and cash flows during 2019 are provided below:

		Dec 31, 2019
Expenses relating to short-term leases (1)	$	448
Interest expense on lease liabilities	$	70
Variable lease payments not included in the measurement of lease liabilities	$	118
Total cash outflows for leases (2)	$	1,178

(1) During 2019, the Company capitalized $305 million of short-term leases as additions to property, plant and equipment.
(2) Comprised of cash outflows relating to lease liabilities, short-term leases, and variable lease payments.

IMPACTS TO THE CONSOLIDATED FINANCIAL STATEMENTS ON TRANSITION

On transition to IFRS 16, the Company recognized $1,539 million of lease liabilities and corresponding lease assets. Lease liabilities were measured at the discounted value of lease payments using a weighted average incremental borrowing rate of 4.0% at January 1, 2019.

A reconciliation showing the impact of adoption of the standard is provided below:

		Jan 1, 2019
Leases previously reported as commitments at December 31, 2018 (1) (2)	$	1,430
Impact of discounting		(317)
Leases previously reported as commitments, discounted at January 1, 2019		1,113
Leases recognized at adoption on January 1, 2019:		
Lease extension options and renewals reasonably certain to be exercised		243
Arrangements determined to be leases under IFRS 16		83
Leases entered into on behalf of a joint operation (3)		100
Lease liabilities recognized at January 1, 2019	$	1,539

(1) At December 31, 2018, the Company did not report any finance leases in accordance with its previous accounting policy for leases.
(2) Commitments for operating leases, previously reported in note 20, are now reported as part of lease liabilities and included in other long-term liabilities in note 12. Operating leases previously reported in note 20 have been aggregated into one line in the reconciliation table. Other non-lease commitments continue to be reported in the table in note 20.
(3) In accordance with the previous accounting for operating leases used in joint operations, the Company reported commitments and related expenses in accordance with the Company's proportionate interest in these joint operations. Under IFRS 16, where the Company acts as the operator of a joint operation, the Company recognizes 100% of the related lease asset and lease liability.

9. Investments

As at December 31, 2019 and 2018, the Company had the following investments:

		2019		2018
Investment in PrairieSky Royalty Ltd.	$	**345**	$	400
Investment in Inter Pipeline Ltd.		**145**		124
	$	**490**	$	524

INVESTMENT IN PRAIRIESKY ROYALTY LTD.

The Company's investment of 22.6 million common shares of PrairieSky Royalty Ltd. ("PrairieSky") does not constitute significant influence, and is accounted for at fair value through profit or loss, measured at each reporting date. As at December 31, 2019, the Company's investment in PrairieSky was classified as a current asset. PrairieSky is in the business of acquiring and managing oil and gas royalty income assets through indirect third-party oil and gas development.

The loss (gain) from the investment in PrairieSky was comprised as follows:

		2019		2018		2017
Fair value loss (gain) from PrairieSky	$	**55**	$	326	$	(3)
Dividend income from PrairieSky		**(17)**		(17)		(17)
	$	**38**	$	309	$	(20)

INVESTMENT IN INTER PIPELINE LTD.

The Company's investment of 6.4 million common shares of Inter Pipeline Ltd. ("Inter Pipeline") does not constitute significant influence, and is accounted for at fair value through profit or loss, measured at each reporting date. As at December 31, 2019, the Company's investment in Inter Pipeline was classified as a current asset. Inter Pipeline is in the business of oil sands transportation, natural gas liquids processing and conventional oil pipelines in Canada and bulk liquid storage in Europe.

The (gain) loss from the investment in Inter Pipeline was comprised as follows:

		2019		2018		2017
Fair value (gain) loss from Inter Pipeline	$	**(21)**	$	43	$	23
Dividend income from Inter Pipeline		**(11)**		(11)		(10)
	$	**(32)**	$	32	$	13

10. Other Long-Term Assets

		2019		2018
North West Redwater Partnership subordinated debt (1)	$	**652**	$	591
Prepaid cost of service toll		**130**		62
Investment in North West Redwater Partnership		**—**		287
Risk management (note 19)		**290**		373
Long-term inventory		**121**		96
Other		**84**		50
		1,277		1,459
Less: current portion		**54**		116
	$	**1,223**	$	1,343

(1) Includes accrued interest.

INVESTMENT IN NORTH WEST REDWATER PARTNERSHIP

The Company's 50% interest in Redwater Partnership is accounted for using the equity method based on Redwater Partnership's voting and decision-making structure and legal form. Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2018, Redwater Partnership commenced commissioning activities in the Project's light oil units while continuing work on the heavy oil units. In the first quarter of 2019, the light oil units transitioned from pre-commissioning and startup to operations and are processing synthetic crude oil into refined products. In December 2019, the light oil refinery completed activities relating to the planned maintenance shutdown. The Project continues to operate as a light oil refinery and will continue to process synthetic crude oil into refined products until the heavy oil units can reliably commence commercial processing of bitumen. As at December 31, 2019, the total estimate of capital costs incurred for the Project, net of margins from pre-commercial sales, was approximately $10 billion.

During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. As at December 31, 2019, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $213 million, for a Company total of $652 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, currently consisting of interest and fees, with principal repayments beginning in 2020 (see note 20). The Company is unconditionally obligated to pay this portion of the cost of service tolls over the 30-year tolling period. As at December 31, 2019, the Company had recognized $130 million in prepaid cost of service tolls (2018 – $62 million).

Redwater Partnership has a secured $3,500 million syndicated credit facility, of which $2,000 million is revolving and matures in June 2021 and the remaining $1,500 million is fully drawn on a non-revolving basis. During 2019, Redwater Partnership extended the $1,500 million non-revolving facility, previously scheduled to mature in February 2020, to February 2021. As at December 31, 2019, Redwater Partnership had borrowings of $2,715 million under the syndicated credit facility.

The assets, liabilities, partners' equity, product sales and equity loss related to Redwater Partnership and the Company's 50% interest at December 31, 2019 and 2018 were comprised as follows:

	2019		2018	
	Redwater Partnership 100% interest	**Company 50% interest**	Redwater Partnership 100% interest	Company 50% interest
Current assets	**$ 248**	**$ 124**	$ 210	$ 105
Non-current assets	**$ 11,328**	**$ 5,664**	$ 11,250	$ 5,625
Current liabilities	**$ 384**	**$ 192**	$ 352	$ 176
Non-current liabilities	**$ 11,310**	**$ 5,655**	$ 10,534	$ 5,267
Partners' equity	**$ (118)**	**$ (59)**	$ 574	$ 287
Product sales	**$ 1,736**	**$ 868**	$ —	$ —
Net loss	**$ 692**	**$ 346**	$ 10	$ 5

During 2019, the Company's interest in Redwater Partnership's net loss was $346 million (2018 – $5 million). Of this, the Company recognized an equity loss of $287 million, reducing the carrying value in Redwater Partnership to $nil. The unrecognized share of losses for 2019 from Redwater Partnership was $59 million (2018 – $nil).

11. Long-Term Debt

		2019		2018
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**1,688**	$	831
Medium-term notes				
3.05% debentures due June 19, 2019		**—**		500
2.60% debentures due December 3, 2019		**—**		500
2.05% debentures due June 1, 2020		**900**		900
2.89% debentures due August 14, 2020		**1,000**		1,000
3.31% debentures due February 11, 2022		**1,000**		1,000
3.55% debentures due June 3, 2024		**500**		500
3.42% debentures due December 1, 2026		**600**		600
4.85% debentures due May 30, 2047		**300**		300
		5,988		6,131
US dollar denominated debt, unsecured				
Bank credit facilities (December 31, 2019 – US$3,745 million; December 31, 2018 – US$2,954 million)		**4,855**		4,031
Commercial paper (December 31, 2019 – US$254 million; December 31, 2018 – US$104 million)		**329**		141
US dollar debt securities				
3.45% due November 15, 2021 (US$500 million)		**648**		682
2.95% due January 15, 2023 (US$1,000 million)		**1,296**		1,364
3.80% due April 15, 2024 (US$500 million)		**648**		682
3.90% due February 1, 2025 (US$600 million)		**778**		819
3.85% due June 1, 2027 (US$1,250 million)		**1,621**		1,706
7.20% due January 15, 2032 (US$400 million)		**519**		546
6.45% due June 30, 2033 (US$350 million)		**454**		478
5.85% due February 1, 2035 (US$350 million)		**454**		478
6.50% due February 15, 2037 (US$450 million)		**583**		614
6.25% due March 15, 2038 (US$1,100 million)		**1,426**		1,501
6.75% due February 1, 2039 (US$400 million)		**519**		546
4.95% due June 1, 2047 (US$750 million)		**972**		1,023
		15,102		14,611
Long-term debt before transaction costs and original issue discounts, net		**21,090**		20,742
Less: original issue discounts, net (1)		**17**		17
transaction costs (1) (2)		**91**		102
		20,982		20,623
Less: current portion of commercial paper		**329**		141
current portion of other long-term debt (1) (2)		**2,062**		1,000
	$	**18,591**	$	19,482

(1) The Company has included unamortized original issue discounts and premiums, and directly attributable transaction costs in the carrying amount of the outstanding debt.

(2) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

BANK CREDIT FACILITIES AND COMMERCIAL PAPER

As at December 31, 2019, the Company had in place revolving bank credit facilities of $4,959 million of which $4,737 million was available for use. Additionally, the Company had in place fully drawn term credit facilities of $6,650 million. Details of these facilities are described below. This excludes certain other dedicated credit facilities supporting letters of credit.

- a $100 million demand credit facility;
- a $750 million non-revolving term credit facility maturing February 2021;
- a $2,425 million revolving syndicated credit facility maturing June 2022;
- a $3,250 million non-revolving term credit facility maturing June 2022;
- a $2,650 million non-revolving term credit facility maturing February 2023;
- a $2,425 million revolving syndicated credit facility maturing June 2023; and
- a £5 million demand credit facility related to the Company's North Sea operations.

During 2019, the Company fully repaid and cancelled the $1,800 million non-revolving term credit facility scheduled to mature in May 2020. In addition, the $2,200 million non-revolving term credit facility, originally due October 2020, was extended to February 2023 and increased to $2,650 million.

During 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon (see note 7). The facility matures in June 2022 and is subject to annual amortization of 5% of the original balance.

Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2019, the non-revolving term credit facilities were fully drawn.

During 2019, the Company extended the $2,425 million revolving syndicated credit facility, of which $330 million was originally due June 2019 and $2,095 million was originally due June 2021, to June 2023. The revolving credit facilities are extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.

During 2019, the Company reduced the £15 million demand credit facility related to the Company's North Sea operations, to £5 million.

The Company's borrowings under its US commercial paper program are authorized up to a maximum US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at December 31, 2019 was 2.5% (December 31, 2018 – 2.6%), and on total long-term debt outstanding for the year ended December 31, 2019 was 4.0% (December 31, 2018 – 3.9%).

As at December 31, 2019, letters of credit and guarantees aggregating to $468 million were outstanding.

MEDIUM-TERM NOTES

During 2019, the Company repaid $500 million of 2.60% medium-term notes and $500 million of 3.05% medium-term notes.

In July 2019, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 2021, replacing the Company's previous base shelf prospectus, which would have expired in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

US DOLLAR DEBT SECURITIES

In July 2019, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2021, replacing the Company's previous base shelf prospectus, which would have expired in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

During 2018, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

SCHEDULED DEBT REPAYMENTS

Scheduled debt repayments are as follows:

Year		Repayment
2020	$	2,391
2021	$	1,552
2022	$	3,879
2023	$	3,894
2024	$	1,148
Thereafter	$	8,226

12. Other Long-Term Liabilities

	2019	2018
Asset retirement obligations	**$ 5,771**	$ 3,886
Lease liabilities (note 8)	**1,809**	—
Share-based compensation	**297**	124
Risk management (note 19)	**112**	17
Deferred purchase consideration (1)	**95**	118
Other	**98**	80
	8,182	4,225
Less: current portion	**819**	335
	$ 7,363	$ 3,890

(1) Relates to the acquisition of the Joslyn oil sands project in 2018, payable in annual installments of $25 million over the next four years.

ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 3.8% (2018 – 5.0%; 2017 – 4.7%) and inflation rates of up to 2% (December 31, 2018 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	2019	2018	2017
Balance – beginning of year	**$ 3,886**	$ 4,327	$ 3,243
Liabilities incurred	**15**	19	12
Liabilities acquired, net	**198**	6	784
Liabilities settled	**(296)**	(290)	(274)
Asset retirement obligation accretion	**190**	186	164
Revision of cost, inflation rates and timing estimates	**412**	(111)	(40)
Change in discount rates	**1,412**	(334)	509
Foreign exchange adjustments	**(46)**	83	(71)
Balance – end of year	**5,771**	3,886	4,327
Less: current portion	**208**	186	92
	$ 5,563	$ 3,700	$ 4,235

Segmented Asset Retirement Obligations

	2019	2018
Exploration and Production		
North America	**$ 2,792**	$ 1,665
North Sea	**816**	707
Offshore Africa	**161**	134
Oil Sands Mining and Upgrading	**2,000**	1,379
Midstream and Refining	**2**	1
	$ 5,771	$ 3,886

SHARE-BASED COMPENSATION

The liability for share-based compensation includes costs incurred under the Company's Stock Option Plan and PSU plans. The Company's Stock Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met.

The Company recognizes a liability for potential cash settlements under these plans. The current portion of the liability represents the maximum amount of the liability payable within the next twelve month period if all vested stock options and PSUs are settled in cash.

		2019		2018		2017
Balance – beginning of year	**$**	**124**	$	414	$	426
Share-based compensation expense (recovery)		**223**		(146)		134
Cash payment for stock options surrendered		**(2)**		(5)		(6)
Transferred to common shares		**(53)**		(120)		(154)
Charged to (recovered from) Oil Sands Mining and Upgrading, net		**5**		(19)		14
Balance – end of year		**297**		124		414
Less: current portion		**227**		92		348
	$	**70**	$	32	$	66

Included within share-based compensation liability as at December 31, 2019 was $62 million (2018 – $13 million; 2017 – $5 million) related to PSUs granted to certain executive employees.

The fair value of stock options outstanding was estimated using the Black-Scholes valuation model with the following weighted average assumptions:

		2019		2018		2017
Fair value	**$**	**7.88**	$	3.33	$	11.82
Share price	**$**	**42.00**	$	32.94	$	44.92
Expected volatility		**26.7%**		27.4%		27.1%
Expected dividend yield		**3.6%**		4.1%		2.5%
Risk free interest rate		**1.7%**		1.9%		1.8%
Expected forfeiture rate		**4.3%**		4.2%		5.0%
Expected stock option life [1]		**4.4 years**		4.4 years		4.5 years

(1) At original time of grant.

The intrinsic value of vested stock options at December 31, 2019 was $75 million (2018 – $27 million; 2017 – $195 million).

13. Income Taxes

The provision for income tax was as follows:

Expense (recovery)		**2019**		2018		2017
Current corporate income tax – North America	**$**	**354**	$	312	$	(145)
Current corporate income tax – North Sea		**112**		28		57
Current corporate income tax – Offshore Africa		**44**		54		45
Current PRT [1] – North Sea		**(89)**		(29)		(132)
Other taxes		**13**		9		11
Current income tax		**434**		374		(164)
Deferred corporate income tax		**(895)**		540		586
Deferred PRT [1] – North Sea		**1**		17		54
Deferred income tax		**(894)**		557		640
Income tax	**$**	**(460)**	$	931	$	476

(1) Petroleum Revenue Tax.

The provision for income tax is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes. The reasons for the difference are as follows:

	2019	2018	2017
Canadian statutory income tax rate	**26.5%**	27.0%	27.0%
Income tax provision at statutory rate	**$ 1,313**	$ 951	$ 776
Effect on income taxes of:			
UK PRT and other taxes	**(76)**	(3)	(67)
Impact of deductible UK PRT and other taxes on corporate income tax	**32**	3	28
Foreign and domestic tax rate differentials	**(48)**	6	(43)
Non-taxable portion of capital (gains) losses	**(65)**	142	(86)
Stock options exercised for common shares	**47**	(41)	33
Income tax rate and other legislative changes	**(1,618)**	—	10
Non-taxable gain on corporate acquisitions	**—**	(119)	(63)
Revisions arising from prior year tax filings	**(41)**	(136)	(3)
Change in unrecognized capital loss carryforward asset	**(65)**	142	(86)
Other	**61**	(14)	(23)
Income tax (recovery) expense	**$ (460)**	$ 931	$ 476

The following table summarizes the temporary differences that give rise to the net deferred income tax liability:

	2019	2018
Deferred income tax liabilities		
Property, plant and equipment and exploration and evaluation assets	**$ 12,074**	$ 12,885
Lease assets	**412**	—
Unrealized risk management activities	**27**	33
PRT deduction for corporate income tax	**—**	1
Investments	**36**	46
Investment in North West Redwater Partnership	**593**	414
Other	**52**	179
	13,194	13,558
Deferred income tax assets		
Asset retirement obligations	**(1,488)**	(1,142)
Lease liabilities	**(416)**	—
Share-based compensation	**(16)**	(5)
Loss carryforwards	**(685)**	(855)
Unrealized foreign exchange loss on long-term debt	**(49)**	(104)
Deferred PRT	**(1)**	(1)
	(2,655)	(2,107)
Net deferred income tax liability	**$ 10,539**	$ 11,451

Movements in deferred tax assets and liabilities recognized in net earnings during the year were as follows:

		2019		2018		2017
Property, plant and equipment and exploration and evaluation assets	**$**	**(775)**	$	281	$	541
Lease assets		**414**		—		—
Unrealized foreign exchange loss (gain) on long-term debt		**55**		(75)		120
Unrealized risk management activities		**(14)**		18		(46)
Asset retirement obligations		**(317)**		175		(88)
Lease liabilities		**(418)**		—		—
Share-based compensation		**(11)**		(5)		—
Loss carryforwards		**170**		(61)		48
Investments		**(10)**		(50)		(2)
Investment in North West Redwater Partnership		**179**		162		30
Deferred PRT		**1**		17		54
PRT deduction for corporate income tax		**—**		(7)		(21)
Other		**(168)**		102		4
	$	**(894)**	$	557	$	640

The following table summarizes the movements of the net deferred income tax liability during the year:

		2019		2018		2017
Balance – beginning of year	**$**	**11,451**	$	10,975	$	9,073
Deferred income tax (recovery) expense		**(894)**		557		640
Deferred income tax expense (recovery) included in other comprehensive income		**8**		(6)		4
Foreign exchange adjustments		**(26)**		41		(29)
Business combinations (note 6, 7)		**—**		(116)		1,287
Balance – end of year	**$**	**10,539**	$	11,451	$	10,975

Current income taxes recognized in each operating segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

During 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by $1,618 million.

During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $10 million.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's reported results of operations, financial position or liquidity.

Deferred income tax assets are recognized for temporary differences to the extent that the realization of the related tax benefit through future taxable profits is probable. The Company has not recognized deferred income tax assets with respect to taxable capital loss carryforwards in excess of $1,000 million in North America, which can be carried forward indefinitely and only applied against future taxable capital gains. In addition, the Company has not recognized deferred income tax assets related to North American tax pools of approximately $750 million, which can only be claimed against income from certain oil and gas properties.

Deferred income tax liabilities have not been recognized on the unremitted net earnings of wholly controlled subsidiaries. The Company is able to control the timing and amount of distributions and no taxes are payable on distributions from these subsidiaries provided that the distributions remain within certain limits.

14. Share Capital

AUTHORIZED

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	2019		2018	
Issued Common shares	**Number of shares** (thousands)	**Amount**	Number of shares (thousands)	Amount
Balance – beginning of year	**1,201,886**	**$ 9,323**	1,222,769	$ 9,109
Issued upon exercise of stock options	**10,871**	**360**	9,975	332
Previously recognized liability on stock options exercised for common shares	**—**	**53**	—	120
Purchase of common shares under Normal Course Issuer Bid	**(25,900)**	**(203)**	(30,858)	(238)
Balance – end of year	**1,186,857**	**$ 9,533**	1,201,886	$ 9,323

PREFERRED SHARES

Preferred shares are issuable in a series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions and conditions attached to the shares will be determined by the Board of Directors of the Company.

DIVIDEND POLICY

The Company has paid regular quarterly dividends in each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 4, 2020, the Board of Directors declared a quarterly dividend of $0.425 per common share, an increase from the previous quarterly dividend of $0.375 per common share, beginning with the dividend payable on April 1, 2020. On March 6, 2019, the Board of Directors declared a quarterly dividend of $0.375 per common share, an increase from the previous quarterly dividend of $0.335 per common share. On February 28, 2018, the Board of Directors declared a quarterly dividend of $0.335 per common share, an increase from the previous quarterly dividend of $0.275 per common share. On March 1, 2017, the Board of Directors declared a quarterly dividend of $0.275 per common share.

NORMAL COURSE ISSUER BID

On May 21, 2019, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 59,729,706 common shares, over a 12-month period commencing May 23, 2019 and ending May 22, 2020. The Company's Normal Course Issuer Bid announced in May 2018 expired on May 22, 2019.

For the year ended December 31, 2019, the Company purchased 25,900,000 common shares at a weighted average price of $36.32 per common share for a total cost of $941 million. Retained earnings were reduced by $738 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2019, the Company purchased 6,970,000 common shares at a weighted average price of $38.84 per common share for a total cost of $271 million.

SHARE-BASED COMPENSATION – STOCK OPTIONS

The Company's Option Plan provides for the granting of stock options to employees. Stock options granted under the Option Plan have terms ranging from five to six years to expiry and vest over a five-year period. The exercise price of each stock option granted is determined at the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the grant. Each stock option granted provides the holder the choice to purchase one common share of the Company at the stated exercise price or receive a cash payment equal to the difference between the stated exercise price and the market price of the Company's common shares on the date of surrender of the stock option.

The Option Plan is a "rolling 7%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 7% of the common shares outstanding from time to time.

The following table summarizes information relating to stock options outstanding at December 31, 2019 and 2018:

	2019			2018		
	Stock options (thousands)		**Weighted average exercise price**	Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of year	**46,685**	**$**	**37.92**	56,036	$	36.67
Granted	**16,314**	**$**	**34.84**	4,256	$	43.75
Surrendered for cash settlement	**(1,003)**	**$**	**34.52**	(392)	$	33.46
Exercised for common shares	**(10,871)**	**$**	**33.16**	(9,975)	$	33.28
Forfeited	**(3,479)**	**$**	**37.65**	(3,240)	$	38.76
Outstanding – end of year	**47,646**	**$**	**38.04**	46,685	$	37.92
Exercisable – end of year	**17,057**	**$**	**38.74**	19,436	$	36.03

The range of exercise prices of stock options outstanding and exercisable at December 31, 2019 was as follows:

			Stock options outstanding			**Stock options exercisable**		
Range of exercise prices			**Stock options outstanding** (thousands)	**Weighted average remaining term** (years)		**Weighted average exercise price**	**Stock options exercisable** (thousands)		**Weighted average exercise price**
$22.90	–	$24.99	2,361	1.03	$	22.90	1,579	$	22.90
$25.00	–	$29.99	3,524	1.04	$	28.85	2,236	$	28.85
$30.00	–	$34.99	5,174	4.97	$	32.38	536	$	32.58
$35.00	–	$39.99	16,635	3.91	$	36.85	2,263	$	37.62
$40.00	–	$44.99	16,117	2.24	$	43.60	8,939	$	43.58
$45.00	–	$46.74	3,835	3.06	$	45.20	1,504	$	45.13
			47,646	3.04	$	38.04	17,057	$	38.74

15. Accumulated Other Comprehensive Income

The components of accumulated other comprehensive income, net of taxes, were as follows:

		2019		2018
Derivative financial instruments designated as cash flow hedges	**$**	**71**	$	13
Foreign currency translation adjustment		**(37)**		109
	$	**34**	$	122

16. Capital Disclosures

The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined at each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2019, the ratio was within the target range at 37%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

		2019		2018
Long-term debt, net [1]	**$**	**20,843**	$	20,522
Total shareholders' equity	**$**	**34,991**	$	31,974
Debt to book capitalization		**37%**		39%

(1) Includes the current portion of long-term debt, net of cash and cash equivalents.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. At December 31, 2019, the Company was in compliance with this covenant.

17. Net Earnings Per Common Share

			2019		2018		2017
Weighted average common shares outstanding – basic (thousands of shares)			**1,190,977**		1,218,798		1,175,094
Effect of dilutive stock options (thousands of shares)			**2,129**		4,960		7,729
Weighted average common shares outstanding – diluted (thousands of shares)			**1,193,106**		1,223,758		1,182,823
Net earnings		**$**	**5,416**	$	2,591	$	2,397
Net earnings per common share	– basic	**$**	**4.55**	$	2.13	$	2.04
	– diluted	**$**	**4.54**	$	2.12	$	2.03

In 2019, the Company excluded 36,834,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share (year ended December 31, 2018 – 23,458,000; 2017 – 17,547,000).

18. Interest and Other Financing Expense

		2019		2018		2017
Interest and other financing expense:						
Long-term debt	**$**	**895**	$	867	$	810
Lease liabilities (1)		**70**		—		—
Less: amounts capitalized on qualifying assets		**(53)**		(69)		(82)
Total interest and other financing expense		**912**		798		728
Total interest income		**(76)**		(59)		(97)
Net interest and other financing expense	**$**	**836**	$	739	$	631

(1) The Company adopted IFRS 16 "Leases" on January 1, 2019 using the modified retrospective approach (see note 8).

19. Financial Instruments

The carrying amounts of the Company's financial instruments by category were as follows:

						2019				
Asset (liability)		**Financial assets at amortized cost**		**Fair value through profit or loss**		**Derivatives used for hedging**		**Financial liabilities at amortized cost**		**Total**
Accounts receivable	**$**	**2,465**	**$**	**—**	**$**	**—**	**$**	**—**	**$**	**2,465**
Investments		**—**		**490**		**—**		**—**		**490**
Other long-term assets		**652**		**—**		**290**		**—**		**942**
Accounts payable		**—**		**—**		**—**		**(816)**		**(816)**
Accrued liabilities		**—**		**—**		**—**		**(2,611)**		**(2,611)**
Other long-term liabilities (1)		**—**		**(21)**		**(91)**		**(1,904)**		**(2,016)**
Long-term debt (2)		**—**		**—**		**—**		**(20,982)**		**(20,982)**
	$	**3,117**	**$**	**469**	**$**	**199**	**$**	**(26,313)**	**$**	**(22,528)**

						2018				
Asset (liability)		Financial assets at amortized cost		Fair value through profit or loss		Derivatives used for hedging		Financial liabilities at amortized cost		Total
Accounts receivable	$	1,148	$	—	$	—	$	—	$	1,148
Investments		—		524		—		—		524
Other long-term assets		591		12		361		—		964
Accounts payable		—		—		—		(779)		(779)
Accrued liabilities		—		—		—		(2,356)		(2,356)
Other long-term liabilities (1)		—		(17)		—		(118)		(135)
Long-term debt (2)		—		—		—		(20,623)		(20,623)
	$	1,739	$	519	$	361	$	(23,876)	$	(21,257)

(1) Includes $1,809 million of lease liabilities (December 31, 2018 – $nil) and $95 million of deferred purchase consideration payable over the next four years (December 31, 2018 – $118 million).

(2) Includes the current portion of long-term debt.

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt. The fair values of the Company's investments, recurring other long-term assets (liabilities) and fixed rate long-term debt are outlined below:

	2019			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3** (4) (5)
Investments (3)	**$ 490**	**$ 490**	**$ —**	**$ —**
Other long-term assets	**$ 942**	**$ —**	**$ 290**	**$ 652**
Other long-term liabilities	**$ (207)**	**$ —**	**$ (112)**	**$ (95)**
Fixed rate long-term debt (6) (7)	**$ (14,110)**	**$ (15,938)**	**$ —**	**$ —**

	2018			
	Carrying amount	Fair value		
Asset (liability) (1) (2)		Level 1	Level 2	Level 3 (4) (5)
Investments (3)	$ 524	$ 524	$ —	$ —
Other long-term assets	$ 964	$ —	$ 373	$ 591
Other long-term liabilities	$ (135)	$ —	$ (17)	$ (118)
Fixed rate long-term debt (6) (7)	$ (15,620)	$ (15,952)	$ —	$ —

(1) Excludes financial assets and liabilities where the carrying amount approximates fair value due to the short-term nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and purchase consideration payable).
(2) There were no transfers between Level 1, 2 and 3 financial instruments.
(3) The fair values of the investments are based on quoted market prices.
(4) The fair value of the deferred purchase consideration included in other long-term liabilities is based on the present value of future cash payments.
(5) The fair value of Redwater Partnership subordinated debt is based on the present value of future cash receipts.
(6) The fair value of fixed rate long-term debt has been determined based on quoted market prices.
(7) Includes the current portion of fixed rate long-term debt.

RISK MANAGEMENT

The Company periodically uses derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The following provides a summary of the carrying amounts of derivative financial instruments held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)	**2019**	2018
Derivatives held for trading		
Foreign currency forward contracts	**$ (10)**	$ 8
Natural gas AECO basis swaps	**(8)**	1
Natural gas AECO fixed price swaps	**(3)**	3
Crude oil WCS (1) differential swaps	**—**	(17)
Cash flow hedges		
Foreign currency forward contracts	**(91)**	70
Cross currency swaps	**290**	291
	$ 178	$ 356
Included within:		
Current portion of other long-term assets	**$ 8**	$ 92
Current portion of other long-term liabilities	**(112)**	(17)
Other long-term assets	**282**	281
	$ 178	$ 356

(1) Western Canadian Select.

During 2019, the Company recognized a gain of $3 million (2018 – gain of $2 million, 2017 – gain of $5 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair values of derivative financial instruments in Level 2 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications. Level 2 fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs as applicable, including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States interest rate yield curves, and Canadian and United States forward foreign exchange rates, discounted to present value as appropriate. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

The changes in estimated fair values of derivative financial instruments included in the risk management asset were recognized in the financial statements as follows:

Asset (liability)		**2019**		2018
Balance – beginning of year	**$**	**356**	$	101
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**(13)**		35
Foreign exchange		**(231)**		260
Other comprehensive income (loss)		**66**		(40)
Balance – end of year		**178**		356
Less: current portion		**(104)**		75
	$	**282**	$	281

Net loss (gain) from risk management activities for the years ended December 31 were as follows:

		2019		2018		2017
Net realized risk management loss (gain)	**$**	**64**	$	(99)	$	(2)
Net unrealized risk management loss (gain)		**13**		(35)		37
	$	**77**	$	(134)	$	35

FINANCIAL RISK FACTORS

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

COMMODITY PRICE RISK MANAGEMENT

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases.

At December 31, 2019, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

	Remaining term	**Volume**	**Weighted average price**	**Index**
Natural Gas				
AECO basis swaps	Jan 2020 – Mar 2020	140,000 MMbtu/d	US$0.93	NYMEX
AECO fixed price swaps	Apr 2020 – Oct 2020	102,500 GJ/d	$1.51	AECO

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

INTEREST RATE RISK MANAGEMENT

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2019, the Company had no interest rate swap contracts outstanding.

FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt, commercial paper and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based.

At December 31, 2019 the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Jan 2020	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2020	–	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at December 31, 2019 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2019, the Company had US$4,564 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$3,999 million designated as cash flow hedges.

FINANCIAL INSTRUMENT SENSITIVITIES

The following table summarizes the annualized sensitivities of the Company's 2019 net earnings and other comprehensive income (loss) to changes in the fair value of financial instruments outstanding as at December 31, 2019, resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those sensitivities disclosed in the Company's other continuous disclosure documents, are limited to the impact of changes in a specified variable applied to financial instruments only and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	2019		2018	
	Increase (decrease) to net earnings	**(Increase) decrease to other comprehensive loss**	Increase (decrease) to net earnings	Increase (decrease) to other comprehensive income
Commodity price risk				
Increase NYMEX/AECO basis US$0.10 MMBtu	**$ 1**	**$ —**	$ —	$ —
Decrease NYMEX/AECO basis US$0.10 MMBtu	**$ (1)**	**$ —**	$ —	$ —
Increase AECO $0.10/Mcf (1)	**$ (1)**	**$ —**	$ (1)	$ —
Decrease AECO $0.10/Mcf (1)	**$ 1**	**$ —**	$ 1	$ —
Increase WCS differential US$1.00/bbl	**$ —**	**$ —**	$ (5)	$ —
Decrease WCS differential US$1.00/bbl	**$ —**	**$ —**	$ 5	$ —
Interest rate risk				
Increase interest rate 1%	**$ (48)**	**$ (21)**	$ (33)	$ (21)
Decrease interest rate 1%	**$ 48**	**$ 24**	$ 33	$ 25
Foreign currency exchange rate risk				
Weakening of the Canadian dollar by US$0.01	**$ (103)**	**$ —**	$ (114)	$ —
Strengthening of the Canadian dollar by US$0.01	**$ 100**	**$ —**	$ 113	$ —

(1) Movements in AECO are based on the Company's contracted AECO fixed price swap volumes at December 31, 2019 and 2018.

b) Credit risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

COUNTERPARTY CREDIT RISK MANAGEMENT

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At December 31, 2019, substantially all of the Company's accounts receivable were due within normal trade terms and the average expected credit loss was approximately 1% of the Company's accounts receivable balance (December 31, 2018 – 1%).

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. At December 31, 2019, the Company had net risk management assets of $265 million with specific counterparties related to derivative financial instruments (December 31, 2018 – $361 million). The carrying amount of financial assets approximates the maximum credit exposure.

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates of the Company's financial liabilities were as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Accounts payable	$	816	$	—	$	—	$	—
Accrued liabilities	$	2,611	$	—	$	—	$	—
Long-term debt (1)	$	2,391	$	1,552	$	8,921	$	8,226
Other long-term liabilities (2)	$	370	$	196	$	436	$	1,014
Interest and other financing expense (3)	$	881	$	813	$	1,771	$	4,856

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.
(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, $233 million; one to less than two years, $171 million; two to less than five years, $391 million; and thereafter $1,014 million.
(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates at December 31, 2019.

20. Commitments and Contingencies

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2019 (1):

		2020		2021		2022		2023		2024		Thereafter
Product transportation (2) (3)	$	730	$	722	$	637	$	726	$	699	$	7,907
North West Redwater Partnership service toll (4)	$	133	$	167	$	157	$	164	$	156	$	2,815
Offshore vessels and equipment	$	69	$	63	$	9	$	—	$	—	$	—
Field equipment and power	$	27	$	21	$	20	$	21	$	20	$	249
Other	$	26	$	20	$	17	$	17	$	17	$	30

(1) Subsequent to the adoption of IFRS 16, the Company reports its payments for lease liabilities in the maturity table in note 19.
(2) On June 27, 2019, the Company assumed $2,381 million of product transportation commitments related to the acquisition of assets from Devon.
(3) Includes commitments pertaining to a 20 year product transportation agreement on the Trans Mountain Pipeline Expansion. In addition, the Company has entered into certain product transportation agreements on pipelines that have not yet received regulatory and other approvals. The Company may be required to reimburse certain construction costs to the service provider under certain conditions.
(4) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, which currently consists of interest and fees, with principal repayments beginning in 2020. Included in the cost of service tolls is $1,260 million of interest payable over the 30 year tolling period (see note 10).

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of its various development projects. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

21. Supplemental Disclosure of Cash Flow Information

		2019		2018		2017
Changes in non-cash working capital:						
Accounts receivable	**$**	**(1,310)**	$	1,233	$	(977)
Current income tax (liabilities) assets		**(164)**		471		527
Inventory		**(194)**		(74)		81
Prepaids and other		**2**		(3)		(28)
Other long-term assets		**117**		—		—
Accounts payable		**39**		(7)		175
Accrued liabilities		**265**		(268)		365
Other long-term liabilities (1) (2)		**(23)**		(351)		469
Net changes in non-cash working capital	**$**	**(1,268)**	$	1,001	$	612
Relating to:						
Operating activities	**$**	**(1,033)**	$	1,346	$	299
Investing activities		**(235)**		(345)		313
	$	**(1,268)**	$	1,001	$	612

		2019		2018		2017
Expenditures on exploration and evaluation assets	**$**	**73**	$	282	$	159
Net proceeds on sale of exploration and evaluation assets		**—**		(16)		(35)
Net expenditures on exploration and evaluation assets	**$**	**73**	$	266	$	124

(1) Included in other long-term liabilities at December 31, 2019 is $95 million of deferred purchase consideration payable over the next four years (December 31, 2018 – $118 million).
(2) Included in other long-term liabilities at December 31, 2017 is $469 million (US$375 million) of deferred purchase consideration paid to Marathon.

The following table summarizes movements in the Company's liabilities arising from financing activities for the years' ended December 31, 2019 and 2018:

		Long-term debt		Cash flow hedges on US dollar debt securities		Lease liabilities		Liabilities from financing activities
At December 31, 2017	$	22,458	$	(139)	$	—	$	22,319
Changes from financing cash flows:								
Repayment of long-term debt, net (1)		(2,831)		—		—		(2,831)
Changes in foreign exchange and fair value (2)		996		(222)		—		774
At December 31, 2018		20,623		(361)		—		20,262
Adoption of IFRS 16 (3)		—		—		1,539		1,539
At January 1, 2019		20,623		(361)		1,539		21,801
Changes from financing cash flows:								
Issue of long-term debt, net (1)		**1,025**		**—**		**—**		**1,025**
Payment of lease liabilities		**—**		**—**		**(237)**		**(237)**
Non-cash changes:								
Lease additions		**—**		**—**		**527**		**527**
Changes in foreign exchange and fair value (2)		**(666)**		**162**		**(20)**		**(524)**
At December 31, 2019	**$**	**20,982**	**$**	**(199)**	**$**	**1,809**	**$**	**22,592**

(1) Includes original issue discounts and premiums, and directly attributable transaction costs.
(2) Includes foreign exchange (gain) loss, changes in the fair value of cash flow hedges on US dollar debt, the amortization of original issue discounts and premiums and directly attributable transaction costs, and derecognitions of lease liabilities.
(3) The Company adopted IFRS 16 "Leases" on January 1, 2019 using the modified retrospective approach (see note 2).

22. Segmented Information

The Company's exploration and production activities are conducted in three geographic segments: North America, North Sea and Offshore Africa. These activities include the exploration, development, production and marketing of crude oil, natural gas liquids and natural gas. The Company's Oil Sands Mining and Upgrading activities are reported in a separate segment from exploration and production activities. Midstream and Refining activities include the Company's pipeline operations, an electricity co-generation system and Redwater Partnership.

Segmented revenue and segmented results include transactions between business segments. Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred. Sales to external customers are based on the location of the seller.

	North America			**North Sea**			**Offshore Africa**		
(millions of Canadian dollars)	**2019**	2018	2017	**2019**	2018	2017	**2019**	2018	2017
Segmented product sales									
Crude oil and NGLs [1]	**$ 9,679**	$ 7,254	$ 7,655	**$ 860**	$ 753	$ 666	**$ 632**	$ 628	$ 579
Natural gas	**1,150**	1,256	1,506	**57**	140	118	**67**	70	53
Other [2]	**6**	—	—	**5**	—	—	**8**	—	—
Total segmented product sales	**10,835**	8,510	9,161	**922**	893	784	**707**	698	632
Less: royalties	**(998)**	(723)	(809)	**(2)**	(2)	(1)	**(42)**	(51)	(41)
Segmented revenue	**9,837**	7,787	8,352	**920**	891	783	**665**	647	591
Segmented expenses									
Production	**2,425**	2,405	2,362	**391**	405	400	**109**	208	226
Transportation, blending and feedstock [1]	**2,935**	2,587	2,291	**19**	22	31	**2**	2	1
Depletion, depreciation and amortization	**3,326**	3,132	3,243	**308**	257	509	**242**	201	205
Asset retirement obligation accretion	**95**	87	80	**28**	29	27	**6**	9	9
Realized risk management (commodity derivatives)	**49**	(10)	(45)	**—**	—	—	**—**	—	—
Gain on acquisition, disposition and revaluation of properties	**—**	(277)	(35)	**—**	(139)	—	**—**	(36)	—
Equity loss (gain) from investments	**—**	—	—	**—**	—	—	**—**	—	—
Total segmented expenses	**8,830**	7,924	7,896	**746**	574	967	**359**	384	441
Segmented earnings (loss) before the following	**$ 1,007**	$ (137)	$ 456	**$ 174**	$ 317	$ (184)	**$ 306**	$ 263	$ 150
Non–segmented expenses									
Administration									
Share-based compensation									
Interest and other financing expense									
Risk management activities (other)									
Foreign exchange (gain) loss									
Loss (gain) from investments									
Total non–segmented expenses									
Earnings before taxes									
Current income tax expense (recovery)									
Deferred income tax (recovery) expense									
Net earnings									

(1) Includes blending and feedstock costs associated with the processing of third party bitumen and other purchased feedstock in the Oil Sands Mining and Upgrading segment.
(2) 'Other' includes recoveries associated with the joint operation partners' share of the costs of lease contracts and other income of a trivial nature.

Inter-segment elimination and Other includes internal transportation and electricity charges. Production, processing and other purchasing and selling activities that are not included in the above segments are also reported in the segmented information as Inter-segment eliminations and Other. In connection with the adoption of IFRS 15 on January 1, 2018, the Company has reclassified certain comparative figures for product sales, production expense and transportation, blending and feedstock expense for the years ended December 31, 2017 in a manner consistent with the presentation adopted for the year ended December 31, 2018.

Operating segments are reported in a manner consistent with the internal reporting provided to the Company's chief operating decision makers.

Oil Sands Mining and Upgrading			Midstream and Refining			Inter–segment elimination and Other			Total		
2019	2018	2017	**2019**	2018	2017	**2019**	2018	2017	**2019**	2018	2017
$11,340	$ 11,521	$ 7,072	**$ 88**	$ 102	$ 102	**$ 351**	$ 410	$ 448	**$ 22,950**	$ 20,668	$ 16,522
—	—	—	**—**	—	—	**145**	148	161	**1,419**	1,614	1,838
6	—	—	**—**	—	—	**—**	—	—	**25**	—	—
11,346	11,521	7,072	**88**	102	102	**496**	558	609	**24,394**	22,282	18,360
(481)	(479)	(167)	**—**	—	—	**—**	—	—	**(1,523)**	(1,255)	(1,018)
10,865	11,042	6,905	**88**	102	102	**496**	558	609	**22,871**	21,027	17,342
3,276	3,367	2,600	**20**	21	16	**56**	58	71	**6,277**	6,464	5,675
1,306	1,087	679	**—**	—	—	**437**	491	527	**4,699**	4,189	3,529
1,656	1,557	1,220	**14**	14	9	**—**	—	—	**5,546**	5,161	5,186
61	61	48	**—**	—	—	**—**	—	—	**190**	186	164
—	—	—	**—**	—	—	**—**	—	—	**49**	(10)	(45)
—	—	(230)	**—**	—	(114)	**—**	—	—	**—**	(452)	(379)
—	—	—	**287**	5	(31)	**—**	—	—	**287**	5	(31)
6,299	6,072	4,317	**321**	40	(120)	**493**	549	598	**17,048**	15,543	14,099
$ 4,566	$ 4,970	$ 2,588	**$ (233)**	$ 62	$ 222	**$ 3**	$ 9	$ 11	**$ 5,823**	$ 5,484	$ 3,243
									344	325	319
									223	(146)	134
									836	739	631
									28	(124)	80
									(570)	827	(787)
									6	341	(7)
									867	1,962	370
									4,956	3,522	2,873
									434	374	(164)
									(894)	557	640
									$ 5,416	$ 2,591	$ 2,397

CAPITAL EXPENDITURES [1]

	2019			2018		
	Net expenditures	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [3]	$ 129	$ (219)	$ (90)	$ 118	$ (52)	$ 66
North Sea	—	—	—	—	—	—
Offshore Africa [4]	35	(2)	33	(54)	—	(54)
Oil Sands Mining and Upgrading [5]	—	—	—	218	(225)	(7)
	$ 164	$ (221)	$ (57)	$ 282	$ (277)	$ 5
Property, plant and equipment						
Exploration and Production						
North America [3]	$ 4,702	$ 918	$ 5,620	$ 2,553	$ (362)	$ 2,191
North Sea	196	153	349	131	(597)	(466)
Offshore Africa [6]	194	(1,476)	(1,282)	228	(86)	142
	5,092	(405)	4,687	2,912	(1,045)	1,867
Oil Sands Mining and Upgrading [7]	1,525	344	1,869	1,229	(166)	1,063
Midstream and Refining	10	—	10	13	—	13
Head office	34	(3)	31	21	—	21
	$ 6,661	$ (64)	$ 6,597	$ 4,175	$ (1,211)	$ 2,964

(1) This table provides a reconciliation of capitalized costs, reported in note 6 and note 7, to net expenditures reported in the investing activities section of the statements of cash flows. The reconciliation excludes the impact of foreign exchange adjustments.
(2) Derecognitions, asset retirement obligations, transfer of exploration and evaluation assets, and other fair value adjustments.
(3) Includes cash consideration paid of $91 million for exploration and evaluation assets and $3,126 million for property, plant and equipment acquired from Devon in 2019.
(4) Excludes the impact of a pre-tax cash gain of $16 million on the disposition of certain exploration and evaluation assets in 2018.
(5) In 2018, total purchase consideration for the acquisition of the Joslyn oil sands project included $222 million for exploration and evaluation assets and $4 million for asset retirement obligations assumed. In addition, following integration of the Joslyn oil sands project into the Horizon mine plan and determination of proved crude oil reserves, the exploration and evaluation assets were transferred to property, plant, and equipment.
(6) Includes a derecognition of property, plant and equipment of $1,515 million following the FPSO demobilization at the Olowi field, Gabon in 2019.
(7) Net expenditures include capitalized interest and share-based compensation.

SEGMENTED ASSETS

	2019	2018
Exploration and Production		
North America	$ 30,963	$ 27,199
North Sea	1,948	1,699
Offshore Africa	1,529	1,471
Other	30	33
Oil Sands Mining and Upgrading	42,006	39,634
Midstream and Refining	1,418	1,413
Head office	227	110
	$ 78,121	$ 71,559

23. Remuneration of Directors and Senior Management

Remuneration of Non-Management Directors

		2019		2018		2017
Fees earned	**$**	**2**	$	2	$	3

Remuneration of Senior Management (1)

		2019		2018		2017
Salary	**$**	**2**	$	2	$	3
Common stock option based awards		**8**		8		10
Annual incentive plans		**6**		4		5
Long-term incentive plans		**20**		15		17
	$	**36**	$	29	$	35

(1) Senior management identified above are consistent with the disclosure on Named Executive Officers provided in the Company's Information Circular to shareholders for the respective years.

24. Events Subsequent to December 31, 2019

Subsequent to December 31, 2019, crude oil benchmark prices decreased substantially due to a drop in global crude oil demand triggered by the impact of the COVID-19 virus on the global economy. In March 2020, crude oil prices decreased further due to a breakdown in negotiations between OPEC and non-OPEC partners regarding proposed production cuts. The recent volatility in the crude oil pricing environment may continue and could impact the Company's earnings and cash flows.

Supplementary Oil & Gas Information for the Fiscal Year Ended December 31, 2019 (Unaudited)

This supplementary crude oil and natural gas information is provided in accordance with the United States Financial Accounting Standards Board ("FASB") Topic 932 – "Extractive Activities – Oil and Gas" and where applicable, financial information is prepared in accordance with International Financial Reporting Standards ("IFRS").

For the years ended December 31, 2019, 2018, 2017 and 2016 the Company filed its reserves information under National Instrument 51-101 – "Standards of Disclosure of Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada.

There are significant differences to the type of volumes disclosed and the basis from which the volumes are economically determined under the United States Securities and Exchange Commission ("SEC") requirements and NI 51-101. The SEC requires disclosure of net reserves, after royalties, using 12-month average prices and current costs; whereas NI 51-101 requires gross reserves, before royalties, using forecast pricing and costs. Therefore the difference between the reported numbers under the two disclosure standards can be material.

For the purposes of determining proved crude oil and natural gas reserves for SEC requirements as at December 31, 2019, 2018, 2017, and 2016 the Company used the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The Company has used the following 12-month average benchmark prices to determine its 2019 reserves for SEC requirements.

Crude Oil and NGLs						Natural Gas		
WTI Cushing Oklahoma	WCS	Canadian Light Sweet	Cromer LSB	North Sea Brent	Edmonton C5+	Henry Hub Louisiana	AECO	BC Westcoast Station 2
(US$/bbl)	(C$/bbl)	(C$/bbl)	(C$/bbl)	(US$/bbl)	(C$/bbl)	(US$/MMBtu)	(C$/MMBtu)	(C$/MMBtu)
55.73	57.29	66.77	66.85	62.54	68.71	2.54	2.02	1.13

A foreign exchange rate of US$1.00/C$1.3297 was used in the 2019 evaluation, determined on the same basis as the 12-month average price.

Net Proved Crude Oil and Natural Gas Reserves

The Company retains Independent Qualified Reserves Evaluators to evaluate and review the Company's proved crude oil, bitumen, synthetic crude oil ("SCO"), natural gas, and natural gas liquids ("NGLs") reserves.

- For the years ended December 31, 2019, 2018, 2017 and 2016, the reports by GLJ Petroleum Consultants Ltd. covered 100% of the Company's SCO reserves. With the inclusion of non-traditional resources within the definition of "oil and gas producing activities" in the SEC's modernization of oil and gas reporting rules, effective January 1, 2010 these reserves volumes are included within the Company's crude oil and natural gas reserves totals.
- For the years ended December 31, 2019, 2018, 2017 and 2016, the reports by Sproule Associates Limited and Sproule International Limited covered 100% of the Company's crude oil, bitumen, natural gas and NGLs reserves.

Proved crude oil and natural gas reserves, as defined within the SEC's Regulation S-X, are the estimated quantities of oil and gas that by analysis of geoscience and engineering data demonstrate with reasonable certainty to be economically producible, from a given date forward, from known reservoirs under existing economic conditions, operating methods and government regulations. Developed crude oil and natural gas reserves are reserves of any category that can be expected to be recovered from existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of drilling a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Undeveloped crude oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Estimates of crude oil and natural gas reserves are subject to uncertainty and will change as additional information regarding producing fields and technology becomes available and as future economic and operating conditions change.

The following tables summarize the Company's proved and proved developed crude oil and natural gas reserves, net of royalties, as at December 31, 2019, 2018, 2017 and 2016:

Crude Oil and NGLs (MMbbl)[1]	North America: Synthetic Crude Oil	North America: Bitumen[2]	North America: Crude Oil & NGLs	North America: North America Total	North Sea	Offshore Africa	Total
Net Proved Reserves							
Reserves, December 31, 2016	2,542	1,301	504	4,347	93	74	4,514
Extensions and discoveries	—	28	17	45	—	—	45
Improved recovery	—	7	19	26	1	—	27
Purchases of reserves in place	2,232	37	67	2,336	—	—	2,336
Sales of reserves in place	—	—	—	—	—	—	—
Production	(100)	(70)	(44)	(214)	(9)	(6)	(229)
Economic revisions due to prices	—	18	17	35	18	1	54
Revisions of prior estimates	282	44	14	340	4	—	344
Reserves, December 31, 2017	4,956	1,365	594	6,915	107	69	7,091
Extensions and discoveries	744	151	17	912	—	—	912
Improved recovery	—	10	50	60	1	3	64
Purchases of reserves in place	—	2	7	9	7	—	16
Sales of reserves in place	—	(4)	—	(4)	—	—	(4)
Production	(148)	(64)	(47)	(259)	(9)	(6)	(274)
Economic revisions due to prices	—	(45)	(18)	(63)	11	1	(51)
Revisions of prior estimates	109	54	1	164	(3)	4	165
Reserves, December 31, 2018	5,661	1,469	604	7,734	114	71	7,919
Extensions and discoveries	**334**	**18**	**12**	**364**	**—**	**—**	**364**
Improved recovery	**—**	**169**	**12**	**181**	**—**	**—**	**181**
Purchases of reserves in place	**—**	**666**	**2**	**668**	**—**	**—**	**668**
Sales of reserves in place	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Production	**(137)**	**(81)**	**(49)**	**(267)**	**(10)**	**(7)**	**(285)**
Economic revisions due to prices[3]	**(288)**	**3**	**—**	**(285)**	**(1)**	**1**	**(285)**
Revisions of prior estimates	**(17)**	**(27)**	**17**	**(28)**	**3**	**6**	**(19)**
Reserves, December 31, 2019	**5,554**	**2,216**	**598**	**8,368**	**105**	**70**	**8,544**
Net proved developed reserves							
December 31, 2016	2,527	384	353	3,264	12	31	3,307
December 31, 2017	4,967	410	399	5,776	28	21	5,825
December 31, 2018	5,661	461	378	6,500	37	34	6,571
December 31, 2019	**5,452**	**661**	**354**	**6,466**	**38**	**39**	**6,543**

(1) Information in the reserves data tables may not add due to rounding.
(2) Bitumen as defined by the SEC, "is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis." Under this definition, all the Company's thermal and primary heavy crude oil reserves have been classified as bitumen.
(3) Reflects the impact of increased royalties at Oil Sands Mining and Upgrading (SCO) due to higher Bitumen pricing resulting in higher royalties and lower net reserves.

2019 total proved Crude Oil and NGLs reserves increased by 625 MMbbl:

- Extensions and discoveries: Increase of 364 MMbbl primarily due to the transfer of reserves from the probable category at Oil Sands Mining and Upgrading (SCO) and extension drilling/future offset additions at various Bitumen, Crude Oil and natural gas (NGLs) properties.
- Improved recovery: Increase of 181 MMbbl primarily due to increased steamflood recovery at the Primrose thermal oil (Bitumen) project.
- Purchases of reserves in place: Increase of 668 MMbbl primarily due to Bitumen property acquisitions from Devon Canada.
- Production: Decrease of 285 MMbbl.
- Economic revisions due to prices: Decrease of 285 MMbbl primarily at Oil Sands Mining and Upgrading (SCO) due to higher Bitumen pricing resulting in higher royalties and lower net reserves.
- Revisions of prior estimates: Decrease of 19 MMbbl primarily due to the 50-year reserves life cutoff at the Primrose thermal oil (Bitumen) project, increased royalties at Oil Sands Mining and Upgrading (SCO) as a result of lower operating costs, and the removal of future extension and infill undeveloped reserves in certain Crude Oil and Bitumen properties because of revised Company development plans, offset by improved performance at the Pelican Lake (Crude Oil) project and various natural gas (NGLs) properties.

2018 total proved Crude Oil and NGLs reserves increased by 828 MMbbl primarily due to the following:

- Extensions and discoveries: Increase of 912 MMbbl primarily due to the addition of the Horizon South Pit to the Horizon oil sands mining and upgrading Project ("Horizon") (SCO), future thermal (Bitumen) well pad additions at Primrose and extension drilling/future offset additions at various primary heavy crude oil (Bitumen), Crude Oil and natural gas (NGLs) properties.
- Improved recovery: Increase of 64 MMbbl primarily due to infill drilling/future offset additions at various primary heavy crude oil (Bitumen), thermal (Bitumen), Crude Oil and natural gas (NGLs) properties as well as thermal (Bitumen) improved recovery additions.
- Purchases of reserves in place: Increase of 16 MMbbl primarily due to property acquisitions in North America and North Sea core areas.
- Sales of reserves in place: Decrease of 4 MMbbl from the primary heavy crude oil (Bitumen) area.
- Production: Decrease of 274 MMbbl.
- Economic revisions due to prices: Decrease of 51 MMbbl primarily due to increased royalties at thermal (Bitumen) and Pelican Lake (Crude Oil) projects resulting from higher prices and uneconomic reserves at several North America natural gas (NGLs) core areas, partially offset by improved reserve life economics at the North Sea.
- Revisions of prior estimates: Increase of 165 MMbbl primarily due to geological model changes and improved mine/extraction/upgrading performance at the oil sands mining and upgrading projects (SCO) and improved recoveries at Primrose (Bitumen).

2017 total proved Crude Oil and NGLs reserves increased by 2,577 MMbbl primarily due to the following:

- Extensions and discoveries: Increase of 45 MMbbl primarily due to future thermal (Bitumen) well pad additions at Primrose and extension drilling/future offset additions at various primary heavy crude oil (Bitumen), Crude Oil and natural gas (NGLs) properties.
- Improved recovery: Increase of 27 MMbbl primarily due to infill drilling/future offset additions at various primary heavy crude oil (Bitumen) and Crude Oil and natural gas (NGLs) properties.
- Purchases of reserves in place: Increase of 2,336 MMbbl due to acquisitions of the Athabasca Oil Sands Project (SCO), Peace River thermal and Cliffdale primary heavy crude oil properties (Bitumen) and at Pelican Lake (Crude Oil).
- Production: Decrease of 229 MMbbl.
- Economic revisions due to prices: Increase of 54 MMbbl primarily due to improved reserves life economics at several North America Bitumen and Crude Oil core areas.
- Revisions of prior estimates: Increase of 344 MMbbl primarily due to Horizon (SCO) revising the stratigraphic well density used to define proved reserves quantities and increasing the Horizon (SCO) total-volume-to-bitumen-in-place-ratio, partially offset by Horizon (SCO) adopting a low fines mine plan. Additionally, there were overall positive revisions at several North America Bitumen and Crude Oil core areas including improved recoveries at Primrose (Bitumen).

Natural Gas (Bcf)[1]	North America	North Sea	Offshore Africa	Total
Net Proved Reserves				
Reserves, December 31, 2016	4,594	25	25	4,644
Extensions and discoveries	261	—	—	261
Improved recovery	179	—	—	179
Purchases of reserves in place	106	—	—	106
Sales of reserves in place	—	—	—	—
Production	(558)	(14)	(7)	(579)
Economic revisions due to prices	403	5	(1)	407
Revisions of prior estimates	214	9	(1)	222
Reserves, December 31, 2017	5,199	25	16	5,240
Extensions and discoveries	90	—	—	90
Improved recovery	414	—	—	414
Purchases of reserves in place	67	—	—	67
Sales of reserves in place	(3)	—	—	(3)
Production	(523)	(11)	(8)	(542)
Economic revisions due to prices	(746)	—	(2)	(748)
Revisions of prior estimates	(192)	13	15	(164)
Reserves, December 31, 2018	4,306	27	21	4,354
Extensions and discoveries	**106**	**—**	**—**	**106**
Improved recovery	**202**	**—**	**—**	**202**
Purchases of reserves in place	**34**	**—**	**—**	**34**
Sales of reserves in place	**—**	**—**	**—**	**—**
Production	**(511)**	**(9)**	**(8)**	**(528)**
Economic revisions due to prices	**246**	**—**	**2**	**248**
Revisions of prior estimates	**346**	**(2)**	**23**	**367**
Reserves, December 31, 2019	**4,728**	**16**	**38**	**4,782**
Net proved developed reserves				
December 31, 2016	2,805	18	18	2,841
December 31, 2017	3,081	22	9	3,112
December 31, 2018	2,382	23	12	2,417
December 31, 2019	**2,342**	**11**	**28**	**2,381**

(1) Information in the reserves data tables may not add due to rounding.

2019 total proved Natural Gas reserves increased by 428 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 106 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 202 Bcf primarily due to infill drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 34 Bcf primarily due to property acquisitions in several North America core areas.
- Production: Decrease of 528 Bcf.
- Economic revisions due to prices: Increase of 248 Bcf primarily due to increased Natural Gas price in North America.
- Revisions of prior estimates: Increase of 367 Bcf primarily due to overall positive revisions in several North America and Offshore Africa core areas as a result of increased recovery and category transfers from probable to proved. The increase is also due to improved economics on undeveloped reserves which, when combined with lower long term royalty rates, results in increased net, after royalties, reserves.

2018 total proved Natural Gas reserves decreased by 886 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 90 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 414 Bcf primarily due to infill drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 67 Bcf primarily due to property acquisitions in several North America core areas.
- Sales of reserves in place: Decrease of 3 Bcf.
- Production: Decrease of 542 Bcf.
- Economic revisions due to prices: Decrease of 748 Bcf due to uneconomic reserves at several North America Natural Gas core areas.
- Revisions of prior estimates: Decrease of 164 Bcf primarily due to the removal of future extension and infill undeveloped reserves at several North America properties as a result of revised Company development plans.

2017 total proved Natural Gas reserves increased by 596 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 261 Bcf primarily due to extension drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 179 Bcf primarily due to infill drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 106 Bcf primarily due to property acquisitions in several North America core areas.
- Production: Decrease of 579 Bcf.
- Economic revisions due to prices: Increase of 407 Bcf due to improved reserves life economics at several North America Natural Gas core areas.
- Revisions of prior estimates: Increase of 222 Bcf primarily due to overall positive revisions at several North America core areas triggered by production optimizations and reduced production costs.

Capitalized Costs Related to Crude Oil and Natural Gas Activities

		2019		
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Proved properties	**$ 117,643**	**$ 7,296**	**$ 3,933**	**$ 128,872**
Unproved properties	**2,510**	**—**	**69**	**2,579**
	120,153	**7,296**	**4,002**	**131,451**
Less: accumulated depletion and depreciation	**(52,824)**	**(5,712)**	**(2,712)**	**(61,248)**
Net capitalized costs	**$ 67,329**	**$ 1,584**	**$ 1,290**	**$ 70,203**

		2018		
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	$ 110,154	$ 7,321	$ 5,471	$ 122,946
Unproved properties	2,600	—	37	2,637
	112,754	7,321	5,508	125,583
Less: accumulated depletion and depreciation	(48,862)	(5,735)	(4,203)	(58,800)
Net capitalized costs	$ 63,892	$ 1,586	$ 1,305	$ 66,783

		2017		
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	$ 106,900	$ 7,126	$ 4,881	$ 118,907
Unproved properties	2,541	—	91	2,632
	109,441	7,126	4,972	121,539
Less: accumulated depletion and depreciation	(44,779)	(5,653)	(3,719)	(54,151)
Net capitalized costs	$ 64,662	$ 1,473	$ 1,253	$ 67,388

Costs Incurred in Crude Oil and Natural Gas Activities

			2019	
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Property acquisitions				
Proved	**$ 3,405**	**$ —**	**$ —**	**$ 3,405**
Unproved	**91**	**—**	**—**	**91**
Exploration	**38**	**—**	**33**	**71**
Development	**4,687**	**349**	**233**	**5,269**
Costs incurred	**$ 8,221**	**$ 349**	**$ 266**	**$ 8,836**

			2018	
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 214	$ 127	$ —	$ 341
Unproved	340	—	(89)	251
Exploration	116	—	35	151
Development	3,245	110	212	3,567
Costs incurred	$ 3,915	$ 237	$ 158	$ 4,310

			2017	
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 15,091	$ —	$ —	$ 15,091
Unproved	321	—	—	321
Exploration	112	—	15	127
Development	3,753	255	101	4,109
Costs incurred	$ 19,277	$ 255	$ 116	$ 19,648

Results of Operations from Crude Oil and Natural Gas Producing Activities

The Company's results of operations from crude oil and natural gas producing activities for the years ended December 31, 2019, 2018 and 2017 are summarized in the following tables:

			2019	
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	**$ 17,348**	**$ 920**	**$ 676**	**$ 18,944**
Production	**(5,701)**	**(391)**	**(109)**	**(6,201)**
Transportation	**(968)**	**(19)**	**(2)**	**(989)**
Depletion, depreciation and amortization	**(4,982)**	**(308)**	**(242)**	**(5,532)**
Asset retirement obligation accretion	**(156)**	**(28)**	**(6)**	**(190)**
Petroleum revenue tax	**—**	**88**	**—**	**88**
Income tax	**(1,468)**	**(105)**	**(79)**	**(1,652)**
Results of operations	**$ 4,073**	**$ 157**	**$ 238**	**$ 4,468**

(millions of Canadian dollars)		2018 North America		North Sea		Offshore Africa		Total
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	$	16,065	$	891	$	647	$	17,603
Production		(5,772)		(405)		(208)		(6,385)
Transportation		(929)		(22)		(2)		(953)
Depletion, depreciation and amortization		(4,689)		(257)		(201)		(5,147)
Asset retirement obligation accretion		(148)		(29)		(9)		(186)
Petroleum revenue tax		—		12		—		12
Income tax		(1,223)		(76)		(51)		(1,350)
Results of operations	$	3,304	$	114	$	176	$	3,594

(millions of Canadian dollars)		2017 North America		North Sea		Offshore Africa		Total
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	$	13,083	$	784	$	578	$	14,445
Production		(4,962)		(400)		(226)		(5,588)
Transportation		(790)		(31)		(1)		(822)
Depletion, depreciation and amortization		(4,463)		(509)		(205)		(5,177)
Asset retirement obligation accretion		(128)		(27)		(9)		(164)
Petroleum revenue tax		—		78		—		78
Income tax		(740)		42		(28)		(726)
Results of operations	$	2,000	$	(63)	$	109	$	2,046

Standardized Measure of Discounted Future Net Cash Flows from Proved Crude Oil and Natural Gas Reserves and Changes Therein

The following standardized measure of discounted future net cash flows from proved crude oil and natural gas reserves has been computed using the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, costs as at the balance sheet date and year-end statutory income tax rates. A discount factor of 10% has been applied in determining the standardized measure of discounted future net cash flows. The Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair value of the crude oil and natural gas properties. Actual net cash flows will differ from the presented estimated future net cash flows due to several factors including:

- Future production will include production not only from proved properties, but may also include production from probable and possible reserves;
- Future production of crude oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future prices and costs rather than 12-month average prices and costs as at the balance sheet date will apply;
- Economic factors such as interest rates, income tax rates, regulatory and fiscal environments and operating conditions will change;
- Future estimated income taxes do not take into account the effects of future exploration and evaluation expenditures; and
- Future development and asset retirement obligations will differ from those estimated.

Future net revenues, development, production and asset retirement obligation costs have been based upon the estimates referred to above. The following tables summarize the Company's future net cash flows relating to proved crude oil and natural gas reserves based on the standardized measure as prescribed in FASB Topic 932 - "Extractive Activities - Oil and Gas":

(millions of Canadian dollars)		2019 North America		North Sea		Offshore Africa		Total
Future cash inflows	**$**	**515,864**	**$**	**10,030**	**$**	**5,858**	**$**	**531,752**
Future production costs		**(194,076)**		**(4,893)**		**(2,081)**		**(201,050)**
Future development costs and asset retirement obligations		**(70,879)**		**(2,648)**		**(1,076)**		**(74,603)**
Future income taxes		**(53,759)**		**(936)**		**(547)**		**(55,242)**
Future net cash flows		**197,150**		**1,553**		**2,154**		**200,857**
10% annual discount for timing of future cash flows		**(136,616)**		**(1)**		**(715)**		**(137,332)**
Standardized measure of future net cash flows	**$**	**60,534**	**$**	**1,552**	**$**	**1,439**	**$**	**63,525**

(millions of Canadian dollars)		2018 North America		North Sea		Offshore Africa		Total
Future cash inflows	$	500,557		$12,002	$	6,447	$	519,006
Future production costs		(193,387)		(5,148)		(2,284)		(200,819)
Future development costs and asset retirement obligations		(63,202)		(2,909)		(1,099)		(67,210)
Future income taxes		(60,526)		(1,484)		(626)		(62,636)
Future net cash flows		183,442		2,461		2,438		188,341
10% annual discount for timing of future cash flows		(126,699)		(545)		(771)		(128,015)
Standardized measure of future net cash flows	$	56,743	$	1,916	$	1,667	$	60,326

(millions of Canadian dollars)		2017 North America		North Sea		Offshore Africa		Total
Future cash inflows	$	413,180	$	8,740	$	4,786	$	426,706
Future production costs		(198,304)		(4,168)		(1,876)		(204,348)
Future development costs and asset retirement obligations		(61,169)		(2,853)		(1,258)		(65,280)
Future income taxes		(35,645)		(595)		(248)		(36,488)
Future net cash flows		118,062		1,124		1,404		120,590
10% annual discount for timing of future cash flows		(73,171)		(59)		(455)		(73,685)
Standardized measure of future net cash flows	$	44,891	$	1,065	$	949	$	46,905

The principal sources of change in the standardized measure of discounted future net cash flows are summarized in the following table:

(millions of Canadian dollars)		**2019**		2018		2017
Sales of crude oil and natural gas produced, net of production costs	**$**	**(11,807)**	$	(10,229)	$	(8,013)
Net changes in sales prices and production costs		**(3,515)**		20,386		7,466
Extensions, discoveries and improved recovery		**5,883**		2,807		481
Changes in estimated future development costs		**(1,889)**		(698)		(5,548)
Purchases of proved reserves in place		**7,418**		396		25,782
Sales of proved reserves in place		**—**		(55)		—
Revisions of previous reserve estimates		**(3,384)**		2,711		4,245
Accretion of discount		**8,062**		6,119		3,075
Changes in production timing and other		**447**		(955)		(662)
Net change in income taxes		**1,984**		(7,061)		(4,236)
Net change		**3,199**		13,421		22,590
Balance - beginning of year		**60,326**		46,905		24,315
Balance - end of year	**$**	**63,525**	$	60,326	$	46,905

Ten-Year Review

Years ended December 31	**2019**	2018	2017	2016	2015	2014	2013	2012	2011	2010 [9]
FINANCIAL INFORMATION [1] (C$ millions, except per share amounts)										
Net earnings (loss)	**5,416**	2,591	2,397	(204)	(637)	3,929	2,270	1,892	2,643	1,673
Per share – basic ($/share)	**4.55**	2.13	2.04	(0.19)	(0.58)	3.60	2.08	1.72	2.41	1.54
Per share – diluted ($/share)	**4.54**	2.12	2.03	(0.19)	(0.58)	3.58	2.08	1.72	2.40	1.53
Cash flows from operating activities	**8,829**	10,121	7,262	3,452	5,632	8,459	7,218	6,209	6,243	6,282
Adjusted funds flow [2]	**10,267**	9,088	7,347	4,293	5,785	9,587	7,477	6,013	6,547	6,333
Per share – basic ($/share)	**8.62**	7.46	6.25	3.90	5.29	8.78	6.87	5.48	5.98	5.82
Per share – diluted ($/share)	**8.61**	7.43	6.21	3.89	5.28	8.74	6.86	5.47	5.94	5.78
Cash flows used in investing activities	**7,255**	4,814	13,102	3,811	5,465	11,177	7,006	5,927	5,963	5,189
Net capital expenditures [3]	**7,121**	4,731	17,129	3,794	3,853	11,744	7,274	6,308	6,414	5,514
Balance sheet information (C$ millions)										
Working capital surplus (deficiency)	**241**	(601)	513	1,056	1,193	(673)	(1,574)	(1,264)	(894)	(1,200)
Exploration and evaluation assets	**2,579**	2,637	2,632	2,382	2,586	3,557	2,609	2,611	2,475	2,402
Property, plant and equipment, net	**68,043**	64,559	65,170	50,910	51,475	52,480	46,487	44,028	41,631	38,429
Total assets	**78,121**	71,559	73,867	58,648	59,275	60,200	51,754	48,980	47,278	42,954
Long-term debt [4]	**20,982**	20,623	22,458	16,805	16,794	14,002	9,661	8,736	8,571	8,485
Shareholders' equity	**34,991**	31,974	31,653	26,267	27,381	28,891	25,772	24,283	22,898	20,368
SHARE INFORMATION [1]										
Common shares outstanding (thousands)	**1,186,857**	1,201,886	1,222,769	1,110,952	1,094,668	1,091,837	1,087,322	1,092,072	1,096,460	1,090,848
Weighted average shares outstanding – basic (thousands)	**1,190,977**	1,218,798	1,175,094	1,100,471	1,093,862	1,091,754	1,088,682	1,097,084	1,095,582	1,088,096
Weighted average shares outstanding – diluted (thousands)	**1,193,106**	1,223,758	1,182,823	1,100,471	1,093,862	1,096,822	1,090,541	1,099,519	1,102,582	1,095,648
Dividends declared ($/share) [5]	**1.50**	1.34	1.10	0.94	0.92	0.90	0.58	0.42	0.36	0.30
Trading statistics [1]										
TSX – C$										
Trading volume (thousands)	**904,013**	806,254	588,422	653,727	728,033	717,580	683,003	729,700	800,044	661,832
Share Price ($/share)										
High	**42.56**	49.08	47.00	46.74	42.46	49.57	36.04	41.12	50.50	45.00
Low	**30.01**	30.11	35.90	21.27	25.01	31.00	28.44	25.58	27.25	31.97
Close	**42.00**	32.94	44.92	42.79	30.22	35.92	35.94	28.64	38.15	44.35
NYSE – US$										
Trading volume (thousands)	**679,697**	796,971	608,008	892,220	951,311	812,521	645,403	844,647	937,481	759,327
Share Price ($/share)										
High	**32.56**	38.19	36.78	35.28	34.46	46.65	33.92	41.38	52.04	44.77
Low	**22.58**	21.85	27.53	14.60	18.94	26.53	26.98	25.01	25.69	30.00
Close	**32.35**	24.13	35.72	31.88	21.83	30.88	33.84	28.87	37.37	44.42
RATIOS										
Debt to book capitalization [6]	**37%**	39%	41%	39%	38%	33%	27%	26%	27%	29%
Return on average common shareholders' equity, after tax [6]	**16%**	8%	8%	(1%)	(2%)	14%	9%	8%	12%	8%
Daily production before royalties per ten thousand common shares (BOE/d) [1]	**9.3**	9.0	7.9	7.3	7.8	7.2	6.2	6.0	5.5	5.8
Total proved plus probable reserves per common share (BOE) [1][7]	**12.0**	11.1	9.7	8.3	8.3	8.1	7.3	7.2	6.9	6.3
Net asset value ($/share) [1][8]	**97.09**	101.89	81.41	74.77	73.39	78.99	72.41	62.38	70.37	64.58

(1) Restated to reflect two-for-one share splits in May 2010.
(2) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The derivation of this measure is discussed in the MD&A.
(3) Net capital expenditures is a non-GAAP measure that the Company considers a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. For additional information and details, refer to the net capital expenditures table in the Company's MD&A.
(4) Includes current portion of long-term debt.
(5) On March 4, 2020, the Board of Directors approved a quarterly dividend of $0.425 per common share, an increase from the previous quarterly dividend of $0.375 per common share. The dividend is payable on April 1, 2020.
(6) Refer to the "Liquidity and Capital Resources" section of the MD&A for the definitions of these items.
(7) Based upon company gross reserves (forecast price and costs, before royalties), using year-end common shares outstanding.

Years ended December 31	**2019**	2018	2017	2016	2015	2014	2013	2012	2011	2010 [9]
OPERATING INFORMATION										
Crude oil and NGLs (MMbbl) [10]										
Company net proved reserves (after royalties)										
North America	**8,129**	7,163	6,423	3,909	3,645	3,380	3,290	3,268	3,007	2,763
North Sea	**109**	119	120	134	158	204	224	227	228	252
Offshore Africa	**70**	72	70	74	74	78	80	85	87	101
	8,307	7,354	6,613	4,117	3,877	3,662	3,594	3,580	3,322	3,116
Company net proved plus probable reserves (after royalties)										
North America	**10,231**	9,456	8,353	6,015	5,806	5,609	5,135	5,119	4,777	4,293
North Sea	**175**	186	180	252	284	308	325	332	349	376
Offshore Africa	**93**	98	102	108	113	119	122	127	131	149
	10,499	9,740	8,635	6,375	6,203	6,036	5,582	5,578	5,257	4,818
Natural gas (Bcf) [10]										
Company net proved reserves (after royalties)										
North America	**5,795**	6,005	6,032	5,845	5,383	5,054	3,684	3,540	3,778	3,638
North Sea	**16**	27	21	41	39	83	91	82	98	78
Offshore Africa	**37**	21	15	23	21	36	38	48	54	76
	5,849	6,053	6,068	5,909	5,443	5,173	3,813	3,670	3,930	3,792
Company net proved plus probable reserves (after royalties)										
North America	**8,556**	8,681	8,454	7,888	7,361	6,791	5,138	4,907	5,125	4,870
North Sea	**21**	38	32	85	96	114	125	102	134	107
Offshore Africa	**52**	44	47	55	50	68	70	76	83	113
	8,630	8,763	8,533	8,028	7,507	6,973	5,333	5,085	5,342	5,090
Total net proved reserves (after royalties) (MMBOE)	**9,282**	8,363	7,625	5,102	4,784	4,524	4,230	4,191	3,977	3,748
Total net proved plus probable reserves (after royalties) (MMBOE)	**11,938**	11,202	10,057	7,713	7,454	7,198	6,471	6,426	6,147	5,666
Daily production (before royalties)										
Crude oil and NGLs (Mbbl/d)										
North America – Exploration and Production	**406**	351	359	351	400	391	344	326	296	271
North America – Oil Sands Mining and Upgrading	**395**	426	282	123	123	111	100	86	40	91
North Sea	**28**	24	23	24	22	17	18	20	30	33
Offshore Africa	**21**	20	20	26	19	12	16	19	23	30
	850	821	685	524	564	531	478	451	389	425
Natural gas (MMcf/d)										
North America	**1,443**	1,490	1,601	1,622	1,663	1,527	1,130	1,198	1,231	1,217
North Sea	**24**	32	39	38	36	7	4	2	7	10
Offshore Africa	**24**	26	22	31	27	21	24	20	19	16
	1,491	1,548	1,662	1,691	1,726	1,555	1,158	1,220	1,257	1,243
Total production (before royalties) (MBOE/d)	**1,099**	1,079	962	806	852	790	671	655	599	632
Product pricing										
Average crude oil and NGLs price ($/bbl) [11]	**55.08**	46.92	48.57	36.93	41.13	77.04	73.81	72.44	79.16	65.81
Average natural gas price ($/Mcf) [11]	**2.34**	2.61	2.76	2.32	3.16	4.83	3.30	2.70	3.99	4.08
Average SCO price ($/bbl) [11] [12]	**70.18**	68.61	63.98	58.59	61.39	100.27	99.18	90.74	101.48	77.89

(8) Net present value, discounted at 10%, of the future net revenue (before income tax and excluding the ARO for development existing as at December 31, 2019) of the Company's total proved plus probable crude oil, natural gas and NGL reserves prepared using forecast prices and costs, as reported in the Company's AIF, plus the estimated market value of core unproved property at $285/acre (2015 to 2019, $300/acre for core unproved property from 2010 to 2014), less net debt and using common shares outstanding. Net debt is long term debt plus/minus the working capital deficit/surplus. Future development costs and abandonment, decommissioning and reclamation costs attributable to future development activity have been applied against the future net revenue.

(9) 2010 comparative figures have been restated in accordance with IFRS issued at December 31, 2011.

(10) Company net reserves were prepared using forecast prices and costs. Numbers may not add due to rounding.

(11) For the years 2011 to 2019, product prices reflect realized product prices before transportation costs. Prior to 2011, product prices were reported net of transportation costs.

(12) For the years 2017 to 2019, average SCO product price includes AOSP realized product prices net of blending and feedstock costs.

Corporate Information

Board of Directors

***Catherine M. Best,** FCA, ICD.D (1)(2)
Corporate Director
Calgary, Alberta

***M. Elizabeth Cannon,** O.C.
Past President and Professor Emeritus,
University of Calgary
Calgary, Alberta

N. Murray Edwards, O.C.
Corporate Director
St. Moritz, Switzerland

***Timothy W. Faithfull** (3)(5)
Corporate Director
London, England

***Christopher L. Fong** (3)(5)
Corporate Director
Calgary, Alberta

***Ambassador Gordon D. Giffin** (1)(4)
Partner, Dentons US LLP
Atlanta, Georgia

***Wilfred A. Gobert** (1)(2)(4)
Corporate Director
Calgary, Alberta

Steve W. Laut (5)
Executive Vice-Chairman,
Canadian Natural Resources Limited
Calgary, Alberta

Tim S. McKay (3)
President,
Canadian Natural Resources Limited
Calgary, Alberta

***Honourable Frank J. McKenna,** P.C., O.C., O.N.B., Q.C. (2)(4)
Deputy Chair, TD Bank Group
Cap Pelé, New Brunswick

***David A. Tuer** (1)(5)
Chairman, Optiom Inc.
Calgary, Alberta

***Annette M. Verschuren,** O.C. (2)(3)
Chairman and Chief Executive Officer, NRSTOR Inc.
Toronto, Ontario

(1) Audit Committee member
(2) Compensation Committee member
(3) Health, Safety, Asset Integrity and Environmental Committee member
(4) Nominating, Governance and Risk Committee member
(5) Reserves Committee member
*Determined to be independent by the Nominating, Governance and Risk Committee of the Board of Directors and pursuant to the independent standards established under National Instrument 58-101 and the New York Stock Exchange Corporate Governance Listing Standards.

Senior Officers

N. Murray Edwards
Executive Chairman

Steve W. Laut
Executive Vice-Chairman

Tim S. McKay
President

Darren M. Fichter
Chief Operating Officer, Exploration and Production

Scott G. Stauth
Chief Operating Officer, Oil Sands

Mark A. Stainthorpe
Chief Financial Officer and Senior Vice-President, Finance

Troy J.P. Andersen
Senior Vice-President, Canadian Conventional
Field Operations

Trevor J. Cassidy
Senior Vice-President, Thermal

Réal M. Cusson
Senior Vice-President, Marketing

Allan E. Frankiw
Senior Vice-President, Production

Jay E. Froc
Senior Vice-President, Oil Sands Mining and Upgrading

Ron K. Laing
Senior Vice-President, Corporate Development and Land

Pamela A. McIntyre
Senior Vice-President, Safety, Risk Management
and Innovation

Bill R. Peterson
Senior Vice-President, Development Operations

Ken W. Stagg
Senior Vice-President, Exploration

Robin S. Zabek
Senior Vice-President, Exploitation

Paul M. Mendes
Vice-President, Legal, General Counsel and
Corporate Secretary

Betty Yee
Vice-President, Land

Corporate Offices

HEAD OFFICE

Canadian Natural Resources Limited
2100, 855 – 2 Street S. W.
Calgary, Alberta T2P 4J8
Telephone: (403) 517-6700
Facsimile: (403) 517-7350
Website: www.cnrl.com

INVESTOR RELATIONS

Telephone: (403) 514-7777
Email: ir@cnrl.com

INTERNATIONAL OFFICE

CNR International (U.K.) Limited
St. Magnus House, Guild Street
Aberdeen AB11 6NJ Scotland

REGISTRAR AND TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario
Computershare Investor Services LLC
New York, New York

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

INDEPENDENT QUALIFIED RESERVES EVALUATORS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta
Sproule Associates Limited
Calgary, Alberta
Sproule International Limited
Calgary, Alberta

STOCK LISTING – CNQ

Toronto Stock Exchange
The New York Stock Exchange

COMPANY DEFINITION

Throughout the annual report, Canadian Natural Resources Limited is referred to as "us", "we", "our", "Canadian Natural", or the "Company".

CURRENCY

All amounts are reported in Canadian currency unless otherwise stated.

ABBREVIATIONS

Abbreviations can be found on page 10.

METRIC CONVERSION CHART

To Convert	To	Multiply by
barrels	cubic metres	0.159
thousand cubic feet	cubic metres	28.174
feet	metres	0.305
miles	kilometres	1.609
acres	hectares	0.405
tonnes	tons	1.102

COMMON SHARE DIVIDEND

The Company paid its first dividend on its common shares on April 1, 2001. Since then, dividends have been paid quarterly. The following table shows the aggregate amount of the cash dividends declared per common share of the Company and accrued in each of its last three years ended December 31, 2019.

	2019	2018	2017
Cash dividends declared per common share (1)	**$ 1.50**	$1.34	$1.10

(1) Annualized dividend value.

NOTICE OF ANNUAL MEETING

In light of the unprecedented public health impact as a result of the outbreak of the novel coronavirus known as COVID-19, Canadian Natural's Annual Meeting of the Shareholders will be held in a virtual online format via live webcast on Thursday, May 7, 2020 at 1:00 p.m. Mountain Daylight Time. Please see our website, www.cnrl.com, for any location information updates.

Corporate Governance

Canadian Natural's corporate governance practices and disclosure of those practices are in compliance with National Policy 58-201 Corporate Governance Guidelines and National Instrument 58-101 Disclosure of Corporate Governance Practices. Canadian Natural, as a "foreign private issuer" in the United States, may rely on home jurisdiction listing standards for compliance with most of the New York Stock Exchange ("NYSE") Corporate Governance Listing Standards but must disclose any significant differences between its corporate governance practices and those required for U.S. companies listed on the NYSE.

Canadian Natural follows Toronto Stock Exchange ("TSX") rules with respect to shareholder approval of equity compensation plans and material revisions to such plans. TSX rules provide that only the creation of or material amendments to equity compensation plans which provide for new issuance of securities are subject to shareholder approval. However, the NYSE requires shareholder approval of all equity compensation plans whether they provide for the delivery of newly issued securities, or rely on securities acquired in the open market by the issuing company for the purposes of redistribution to plan beneficiaries, and material revisions to such plans. Canadian Natural has a performance share unit plan pursuant to which common shares are purchased through the TSX. This is not a new issue of securities under the performance share unit plan and under TSX rules the plan is not subject to shareholder approval.

Canadian Natural has included as exhibits to its Annual Report on Form 40-F for the 2019 fiscal year filed with the United States Securities and Exchange Commission certificates of the Chief Executive Officer and Chief Financial Officer certifying as to disclosure controls and procedures and internal control over financial reporting.

Canadian Natural

2100, 855 – 2 Street S.W.
Calgary, AB T2P 4J8

T (403) 517-6700
F (403) 517-7350
E ir@cnrl.com

www.cnrl.com