Second Quarter 2019 Results

AltaGas

August 1, 2019

Forward-Looking Information

This presentation contains forward-looking statements. When used in this presentation, the words "will", "intend", "plan", "potential", "generate", "grow", "deliver", "can", "continue", "drive", "anticipate", "target", "come", "create", "position", "achieve", "seek", "propose", "forecast", "estimate", "expect", "solution", "outlook", "assumes" and similar expressions, as they relate to AltaGas or any affiliate of AltaGas, are intended to identify forward-looking statements. In particular, this presentation contains forward-looking statements with respect to, among others things, strategy, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. Specifically, such forward-looking statements included in this document include, but are not limited to, statements with respect to the following: estimated 2019 EBITDA attributable to Stonewall and distributed generation assets; anticipated closing date of the distributed generation asset sale; target of $3 billion in net debt reduction in 2019; anticipated asset sales for the remainder of 2019; use of proceeds from asset sales; operational priorities; anticipated sales volumes from RIPET for the remainder of 2019; expectations for the FEI-EDM spread for the balance of 2019; expected maximum capability of 80,000 bbl/day at RIPET; improved Western Canadian netbacks obtained by providing access to Asian markets; anticipated in-service dates for North Pine facility, Townsend facility, Nig Creek gas plant and other Utilities and Midstream capital projects; expectation for significant growth in the Utilities segment; expected application, decision and effective dates for new rate cases; anticipated benefit in 2019 from new rates at Washington Gas; anticipated $1.3 billion 2019 capital program; anticipated sources and uses of growth capital; total funding requirement of $2.1 billion prior to de-levering; total funding plan for 2019 of $4 billion; *near-term financial and operational priorities; drivers expected to impact 2020 EBITDA; expected decline in utilities earnings in third quarter of 2019; expected sources and uses of 2019 funding plan; expectation that hybrid or preferred offering will only be executed on an opportunistic basis; expectation that capital and funding plan, dividend reduction and lower corporate risk profile will contribute to improving investment grade metrics; expectation that metrics will support an investment grade credit rating; expectation that credit profile will continue to improve; Normalized EBITDA guidance of $1.2 to $1.3 billion for 2019; Normalized EBITDA guidance by segment for 2019; expectation to add EPS to guidance metric; expectation for 2020 EBITDA to be at least equal to 2019 levels; improving Debt/EBITDA to approximately 5.5 at end of 2019; expected 2019 Normalized EBITDA quarterly profile on an enterprise and segmented basis; 2019 Guidance for Normalized FFO, AFFO and UAFFO; anticipated maintenance capital expenses in 2019 and expected expenditures on the Accelerated Replacement Program.*
Information and statements contained in this presentation that are not historical facts may be forward-looking statements.

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect AltaGas' current views with respect to future events based on certain material factors and assumptions and are subject to certain risks and uncertainties, including, without limitation, access to and use of capital markets; market value of AltaGas' securities; AltaGas' ability to pay dividends; AltaGas' ability to service or refinance its debt and manage its credit rating and risk; prevailing economic conditions; potential litigation; AltaGas' relationships with external stakeholders, including Indigenous stakeholders; volume throughput and the impacts of commodity pricing, supply, composition and other market risks; available electricity prices; interest rate, exchange rate and counterparty risks; legislative and regulatory environment; underinsured losses; weather, hydrology and climate changes; the potential for service interruptions; availability of supply from Cook Inlet; availability of biomass fuel; AltaGas' ability to economically and safely develop, contract and operate assets; AltaGas' ability to update infrastructure on a timely basis; AltaGas' dependence on certain partners; impacts of climate change and carbon taxing; effects of decommissioning, abandonment and reclamation costs; impact of labour relations and reliance on key personnel; cybersecurity risks; and other factors set out in AltaGas' continuous disclosure documents. Many factors could cause AltaGas' or any of its business segments' actual results, performance or achievements to vary from those described in this presentation including, without limitation, those listed above as well as the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this presentation as intended, planned, anticipated, believed, sought, proposed, forecasted, estimated or expected, and such forward-looking statements included in this presentation herein should not be unduly relied upon. These statements speak only as of the date of this presentation. AltaGas does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this presentation are expressly qualified by this cautionary statement.

Financial outlook information contained in this presentation about prospective financial performance, financial position or cash flows is based on assumptions about future events, including, without limitation, economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this presentation should not be used for purposes other than for which it is disclosed herein.
In this presentation we use certain supplementary measures, including EBITDA, Normalized EBITDA, Normalized Net Loss; Normalized Funds from Operations ("FFO"), AFFO and UAFFO and Net Debt that do not have any standardized meaning as prescribed under U.S. generally accepted accounting principles ("GAAP") and, therefore, are considered non-GAAP measures. AltaGas' method of calculating these non-GAAP measures may differ from the methods used by other issuers. Readers are advised to refer to AltaGas' Management's Discussion and Analysis ("MD&A") as at and for the three and six months ended June 30, 2019 for a description of the manner in which AltaGas calculates such non-GAAP measures and for a reconciliation to the nearest GAAP financial measure.

Readers are also cautioned that these non-GAAP measures should not be considered as alternatives to other measures of financial performance calculated in accordance with GAAP. Additional information relating to AltaGas can be found on its website at www.altagas.ca. The continuous disclosure materials of AltaGas, including its annual and interim MD&A and Consolidated Financial Statements, Annual Information Form, Information Circular, material change reports and press releases, are also available through AltaGas' website or directly through the SEDAR system at www.sedar.com and provide more information on risks and uncertainties associated with forward-looking statements.
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Randy Crawford

Delivering on Plan

Randy Crawford
President and Chief Executive Officer

Welcome James Harbilas

Executive Vice President and Chief Financial Officer

- Deep background in both energy and utilities
- Proven track record in business optimization and integration
- Ability to build and transform functions
- Strong cultural and values alignment

Second Quarter Highlights

Strong Start to 2019, Positioned for the Future

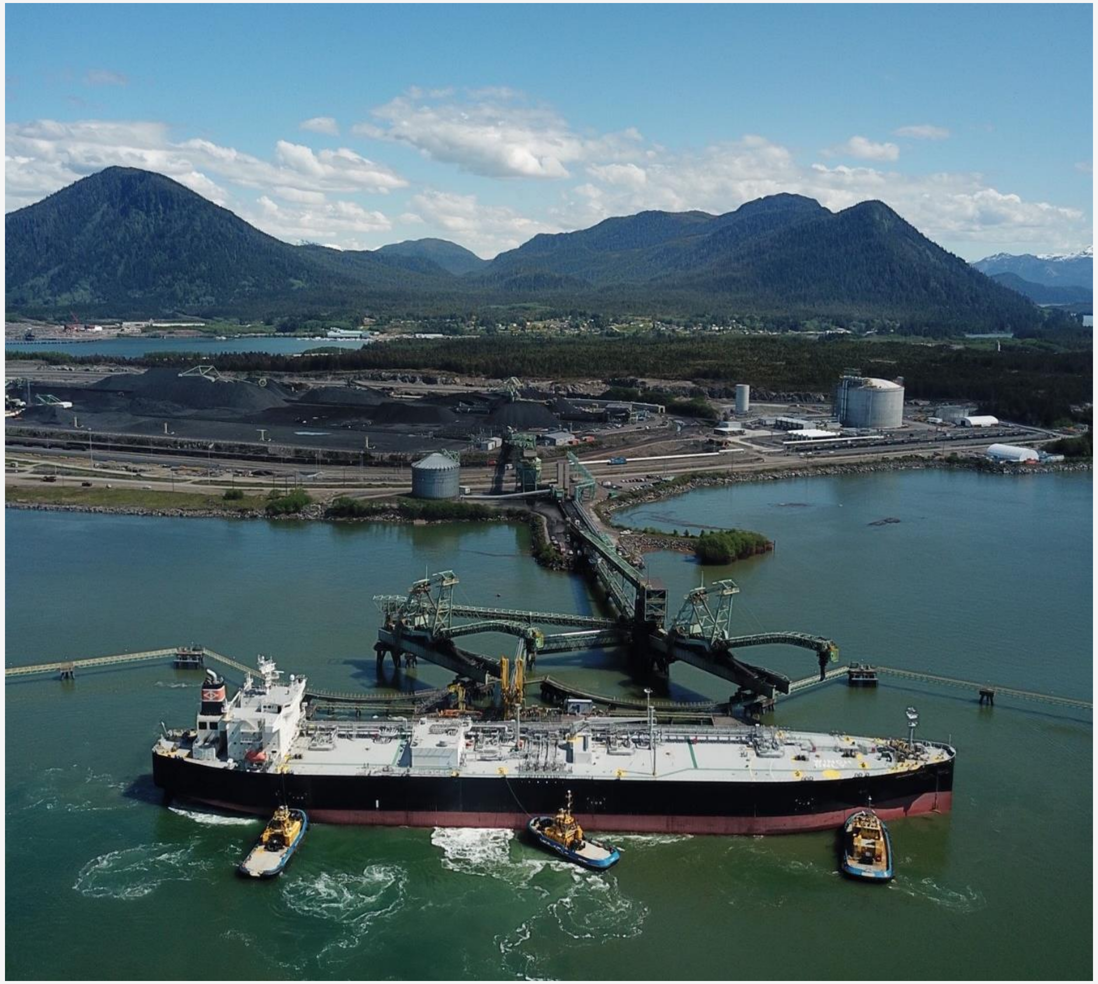
Q2 2019 **Normalized EBITDA[1] of $203M**

Commissioned RIPET in May 2019

Announced **$1.3B in Asset Sales**

Reduced Net Debt[1] by $2B YTD

SEMCO Gas **Rate Case Filed**



1 Non-GAAP measure; see discussion in the advisories

Announced $1.3 Billion of Non-Core Asset Sales

Well-positioned to achieve 2019 asset sales target of $1.5 - $2 billion

Distributed Generation Assets

- Included 322 MW of contracted distributed generation assets located in 20 states and in the District of Columbia
- Total gross proceeds of ~US$720 million
- 2019E EBITDA[1] of ~US$60 million
- Sale expected to close in Q3 2019

Stonewall Gas Gathering System

- 1.4 Bcf/d, 67-mile gathering system transporting from various production points in West Virginia to the Columbia Gas Pipeline
- Total gross proceeds of ~US$280 million
- 2019E EBITDA[1] of ~US$23 million
- Sale closed May 31, 2019

1 Non-GAAP measure; see discussion in the advisories
See "Forward-looking Information“

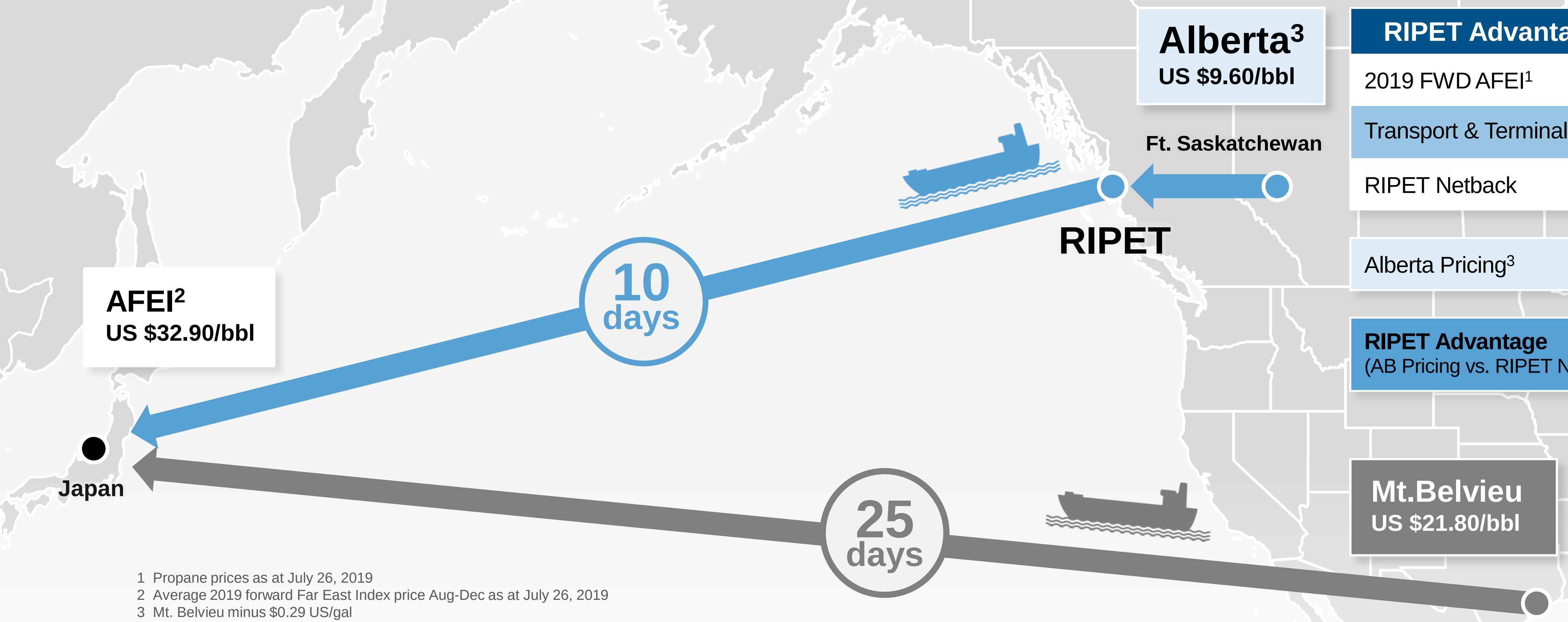
Near-Term Operational Priorities

Priorities	Actions
First cargo out of RIPET early Q2 2019	✓ Complete construction and initiate operational phase ✓ Introduce feedstock to fill the LPG tank ✓ First cargo in May 2019
Capitalize on structural advantage within Canadian Midstream to maximize returns and drive growth	✓ Provide upstream producers with access to export markets ▪ Leverage integrated service offering to attract additional volumes ✓ Tourmaline liquids handling arrangement

Enhance returns across our Utilities and implement performance-based culture focused on operational excellence and prudent capital allocation	▪ Drive operational excellence
	▪ Improve the customer experience
	▪ Achieve more timely recovery of invested capital
	    ▪ Maryland rate case
	    ▪ SEMCO Gas rate case
	✓ New incentive performance program with new value-drivers

RIPET Netback Advantage

RIPET provides enhanced netbacks to producers – At current propane prices[1] the RIPET advantage is estimated at ~US$5.00/bbl



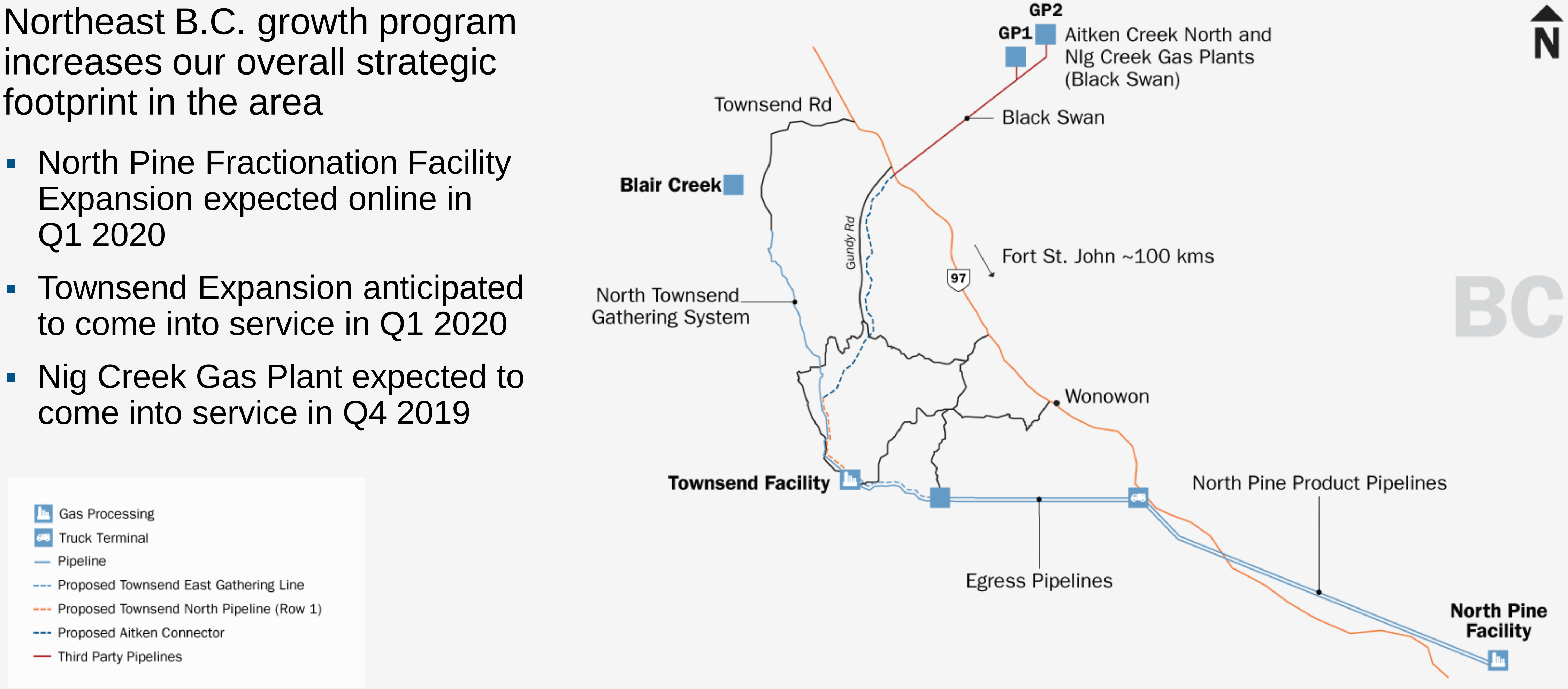
RIPET Advantage (US$/bbl)	
2019 FWD AFEI[1]	~$32.90
Transport & Terminalling[4]	~$18.30
RIPET Netback	~$14.60
Alberta Pricing[3]	~$9.60
RIPET Advantage (AB Pricing vs. RIPET Netback)	**~$5.00**

1 Propane prices as at July 26, 2019
2 Average 2019 forward Far East Index price Aug-Dec as at July 26, 2019
3 Mt. Belvieu minus $0.29 US/gal
4 Transportation and Terminalling charges include: pipeline transportation fees; rail transportation and loading fees; RIPET operating and capital charges; and ocean freight and port fees. See "Forward-looking Information"

Utilize our Existing Infrastructure to Deliver Strong Integrated Economics

Northeast B.C. growth program increases our overall strategic footprint in the area

- North Pine Fractionation Facility Expansion expected online in Q1 2020
- Townsend Expansion anticipated to come into service in Q1 2020
- Nig Creek Gas Plant expected to come into service in Q4 2019



2019: Drive Operational Excellence at the Utilities

Opportunities to unlock embedded organic growth

Operating a Safe and Reliable System	Providing Exceptional Customer Service	Enhancing Efficiencies to Reinvest Earnings and Increase Returns
▪ Improving system reliability and upgrading aging infrastructure through accelerated replacement programs	▪ Regularly conduct customer satisfaction surveys and monitor responsiveness to customer calls and inquiries ▪ Implementation of new technologies to improve customer interfaces	▪ Accelerate returns through the execution of strategic projects (Marquette Connector) ▪ Implementation of new technologies to improve the dispatch and utilization of leak response and remediation resources

Rate Case Status

	2018			2019				2020	2021
	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1 – Q4	Q1 – Q4
Maryland					**APR.** Rate Case Filed ($36M[1], 10.4% ROE)		**NOV.** Final Decision **DEC.** New Rates		
Virginia		**JUL.** Rate Case Filed ($38M[2], 10.3% ROE)		**JAN.** Interim Rates			**LATE 2019** Final Decision		
Washington D.C.[3]			**DEC.** Project*pipes* 2 Application					**Date TBD** Rate Case To Be Filed	
SEMCO					**MAY.** Rate Case Filed ($38M[4], 10.5% ROE)			**MAR.** Final Decision **APR.** New Rates no later than April 1, 2020	
ENSTAR									**Mid-2021** Rate Case To Be Filed
CINGSA	**APR.** Rate Case Filed ($(4)M[5], 11.875% ROE)					**AUG.** Final Decision			

1 Partially offset by a reduction of ~US$5 million in surcharges currently paid by customers for system upgrades.
2 Includes proposed increases of ~US$38 million, of which ~US$15 million relates to costs being collected through the monthly SAVE surcharges for accelerated pipeline replacement.
3 Requesting approval of ~US$305 million in accelerated infrastructure replacement in the District of Columbia during the 2019 to 2024 period.
4 Increase SEMCO Gas's base rates by ~US$38 million on an annual basis established with a forecasted test year of 2020. In addition, filing also includes the addition of a new MRP and the introduction of an Infrastructure Reliability Improvement Program (IRIP) to recover the capital costs associated with the replacement of certain mains, services, and other infrastructure through surcharges similar to the currently-enacted MRP program.
5 Reducing rates by US$4 million due to a lower rate base, lower ROE and lower federal income tax.

Delivering on the Plan

1H 2019: Refocused company delivers results

- Strong results in first half of 2019 position us well to achieve 2019 guidance
- Delivering on the balanced funding plan: strengthening the balance sheet with $2 billion reduction in net debt
- Cornerstone Midstream asset, RIPET, brought into service on-time and on-budget

2020: Unlocking the growth potential of our assets

- Appropriate capital discipline, hurdle rates and business optimization, in addition to driving operational excellence, will position us well to deliver strong performance
- Leverage our expertise along the energy value chain to connect customers with premier energy solutions
- Capture more timely returns and drive rate base growth at our Utilities

James Harbilas

Q2 2019 Results and Capital Funding Update

James Harbilas
Executive Vice President and Chief Financial Officer

Highlights

($CAD unless otherwise noted)

$203M
Q2 Normalized EBITDA[1]

$120M
Q2 Normalized FFO[1]

$5M
Q2 Normalized Net Loss[1]

$1.3B
2019 Announced Asset Sales

1 Non-GAAP measure; see discussion in the advisories

Contributions from WGL Continue to Drive Results; Strong Performance in Base Business

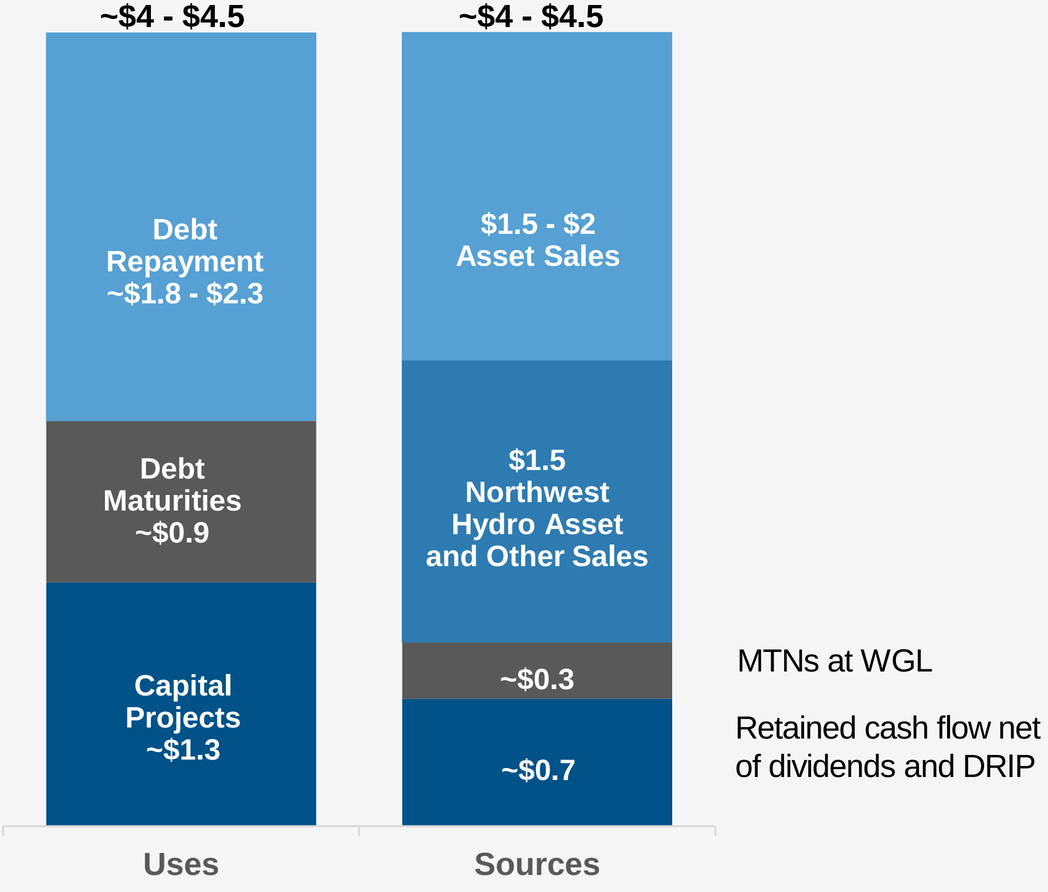
($ millions)

Q2 2019 Normalized EBITDA[1]	Q2 2019	Q2 2018	Variance	Q2 2019 vs Q2 2018 Normalized EBITDA Drivers	
Utilities	81	50	+31	+ WGL (+$41M) + ACI equity income + Lower operating expenses + FX – stronger U.S. dollar	- ACI IPO (-$14M) - Warmer weather in Alaska
Midstream	97	48	+49	+ WGL (+$21M) + RIPET – 5 weeks in service ($13M) + Petrogas – higher margins and volumes + Higher revenues at Harmattan + Aitken Creek contributions + Higher realized frac spreads (after hedging)	- Lower NGL marketing margins - Asset Sales (-$3M) - Reduced ownership at Younger
Power	34	75	-41	+ WGL (+$15M) + FX – stronger U.S. dollar	- Asset sales (-$56M) - Extended planned outage at Blythe (-$3M)
Corporate	(9)	(7)	-2		- Higher information technology related costs
Total Normalized EBITDA	**203**	**166**	**+37**		

1 Non-GAAP financial measure; see discussion in the advisories
See "Forward-looking Information"

Robust Asset Sales Provide Flexibility in 2019 Funding Plan

2019 Sources and Uses
($ billions)



Secured Capital Program

(C$millions unless otherwise specified)

Utility Capital Projects	Expected Capex[1,2]	Target In-Service[1]
Utility 2019 Annual Capital	~$625	2019
Marquette Connector Pipeline	US$154	2019
Midstream Capital Projects		
Nig Creek Plant	$100	Q4 2019
Northeast B.C. Pipeline Projects	$68	Q4 2019, pending regulatory approvals
Townsend Expansion and Mercaptan Treating	$165	Q1 2020
North Pine Expansion	$58	Q1 2020
Mountain Valley Pipeline	US$350	Mid-2020
MVP Southgate Project	US$20	Late 2020
Central Penn Expansion (Leidy South)	US$50	Q4 2021

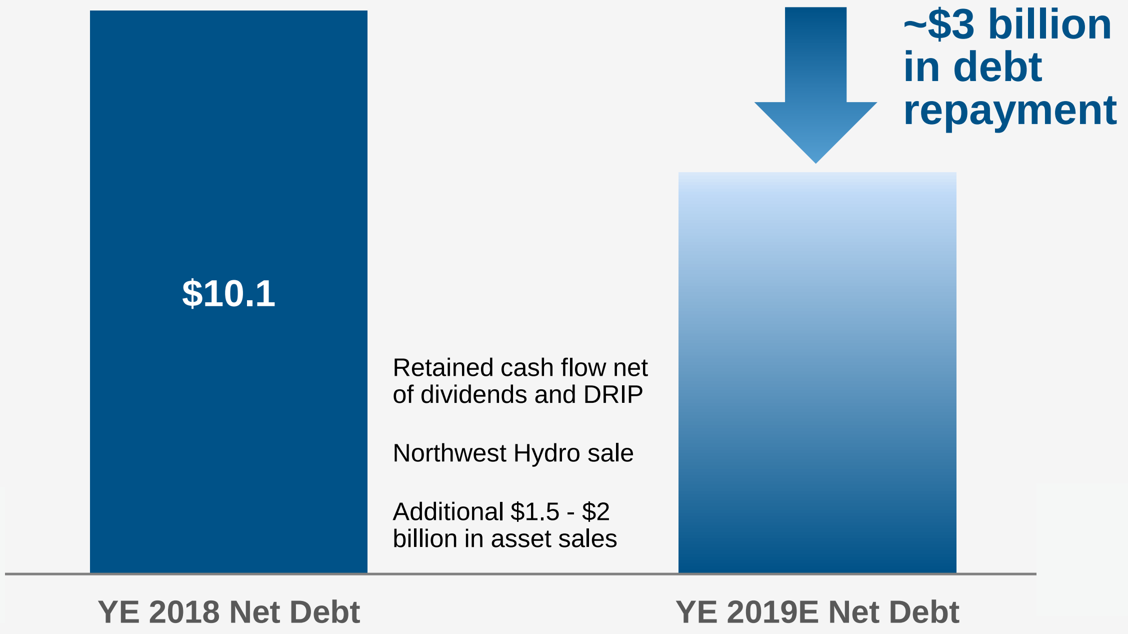
- Well-positioned to meet asset sale target of $1.5 - $2 billion with $1.3 billion announced to-date in 2019
- Hybrid market considered only on an opportunistic basis

1 Expectations based on most recent public disclosure / financial reports for AltaGas
2 Reflects AltaGas' share of the total cost (both incurred and expected)
See "Forward-looking Information"

De-leveraging Program on Track

~$2 billion reduction in net debt year-to-date

Net Debt[1]
($ billions)



2019 Plan Supports

- Lower debt and stronger balance sheet
- Improving net debt/EBITDA metrics to ~5.5x at year-end[2]
- Commitment to investment grade credit rating

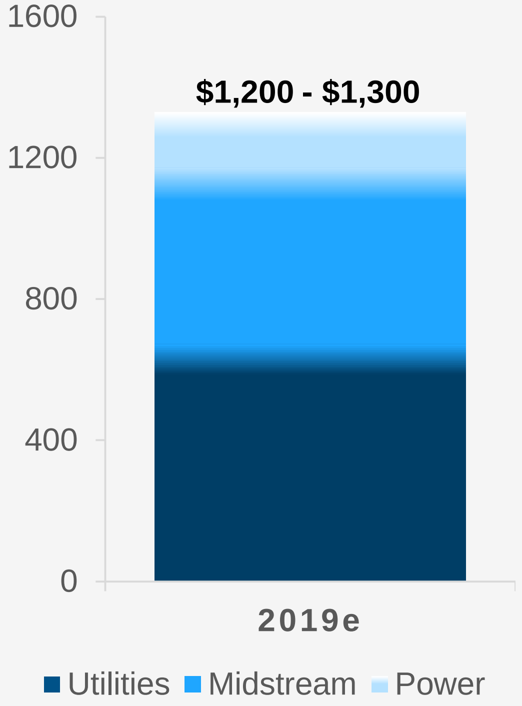
1 Non-GAAP financial measure; see discussion in the advisories
2 Internal calculation uses GAAP treatment for preferred shares as equity
See "Forward-looking Information"

2019 Outlook Unchanged

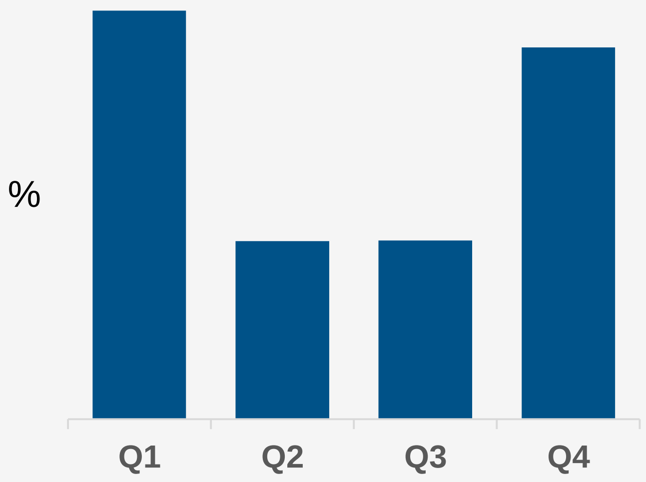
Significant Opportunity for Rebased Business in 2020

2019 EBITDA[1] Guidance

($ millions)



2019 Normalized EBITDA Quarterly Profile[2]



2020 Drivers

- ▲ Rate base and customer growth at Utilities
- ▲ RIPET
- ▲ Marquette Connector Pipeline
- ▲ Additional fractionation and gas processing volumes
- ▼ Asset sales

1 Non-GAAP financial measure; see discussion in the advisories.
2 Includes 2019 asset sales announced to date
See "Forward-looking Information"

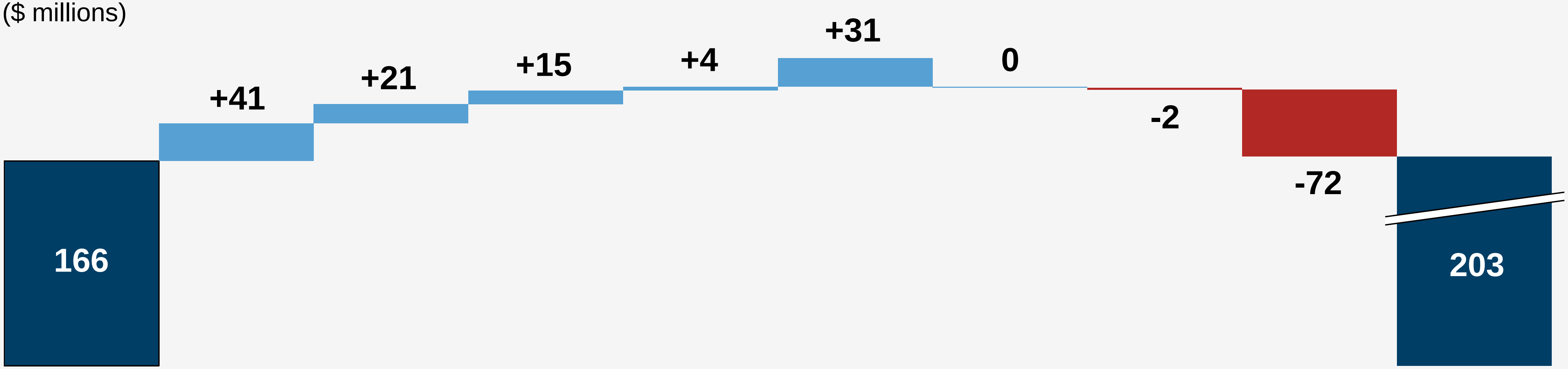
AltaGas | Our Strategy

We leverage the strength of our assets and expertise along the energy value chain to connect customers with premier energy solutions – from the wellsites of upstream producers to the doorsteps of homes and businesses, to new markets around the world.

Appendix

Q2 Normalized EBITDA[1] Walk Down

2019 Q2 Actuals vs. 2018 Q2 Actuals – Normalized EBITDA[1]
($ millions)



Q2 2018 Actual	WGL Utilities	WGL Midstream	WGL Power	ALA Utilities	ALA Midstream	ALA Power	Corporate/ Other	Asset Sales	Q2 2019 Actual
	▲ Rate base and customers ▲ Higher rates ▲ Interruptible conversions ▼ Lower asset optimization ▼ O&M and leak repair cost	▲ Central Penn in-service ▲ MVP ▼ Higher O&M ▼ Lower asset optimization ▼ Lower commodity margins ▼ Stonewall asset sale	▲ Favourable FX ▼ Higher capacity prices	▲ Higher rates ▲ Customer growth ▲ ACI equity income ▲ Favourable FX ▼ U.S. tax reform ▼ Weather	▲ RIPET ▲ Aitken Creek ▲ Petrogas ▲ Harmattan ▲ Realized frac spreads ▲ Frac volumes ▼ Younger ownership change ▼ NGL spot prices	▲ Favourable FX ▼ Biomass ▼ Blythe outage		▼ ACI IPO ▼ San Joaquin ▼ Northwest Hydro ▼ Non-core Midstream and Power	

1 Non-GAAP financial measure; see discussion in the advisories

YTD 2019 – Normalized EBITDA[1] Variance

($ millions)

YTD 2019 Normalized EBITDA[1]	YTD 2019	YTD 2018	Variance	YTD 2019 vs YTD 2018 Normalized EBITDA Drivers	
Utilities	422	162	+260	+ WGL (+$295M) + Higher utility rates and customer growth + FX – stronger U.S. dollar + Colder weather in Michigan + ACI equity income	- ACI IPO (-$49M) - U.S. tax reform - Lower storage volumes (CINGSA) - Warmer weather in Alaska
Midstream	204	119	+85	+ WGL (+$56M) + RIPET ($13M) + Petrogas – higher export volumes at Ferndale and improved margins + Higher revenues at Harmattan + Aitken Creek contributions + Higher realized frac spreads (after hedging)	- Lower frac exposed volumes due to reduced ownership at Younger - Lower NGL marketing margins - Asset Sales (-$7M)
Power	61	116	-55	+ WGL (+$28M)	- Asset sales (-$81M) - Extended planned outage at Blythe
Corporate	(18)	(9)	-9		- Higher information technology related costs - Higher expenses related to employee incentive plans as a result of recent share price appreciation
Total Normalized EBITDA	**669**	**388**	**+281**		

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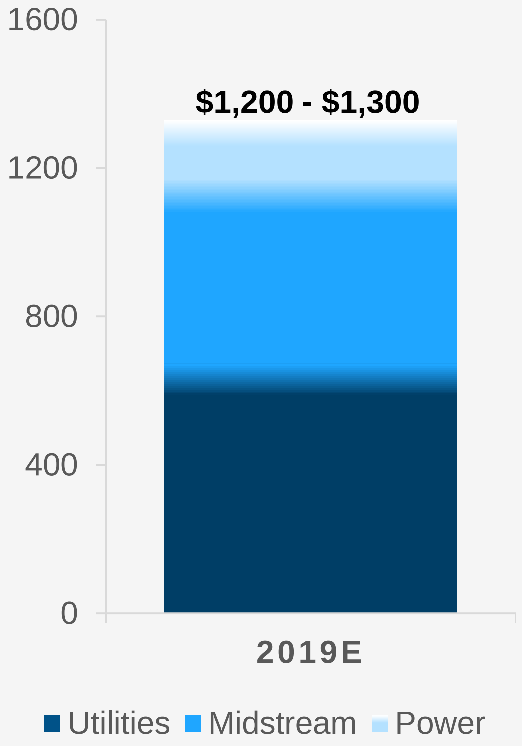
1 Non-GAAP financial measure; see discussion in the advisories
See "Forward-looking Information“

2019 Outlook Remains Unchanged

2019 Normalized EBITDA[1] Guidance
($ millions)



($ millions)

	2019E
Normalized EBITDA[1]	**$1,200 - $1,300**
Normalized FFO[1]	**$850 - $950**
Normalized AFFO[1]	**$750 - $850**
Normalized UAFFO[1]	**$500 - $600**
Growth Capital Expenditures	**$1,300**
Midstream Maintenance Capital	**$14**
Power Maintenance Capital	**$21**

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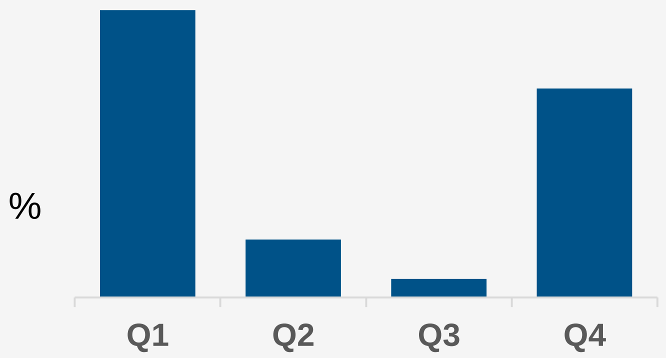
1 Non-GAAP financial measure; see discussion in the advisories
See "Forward-looking Information"

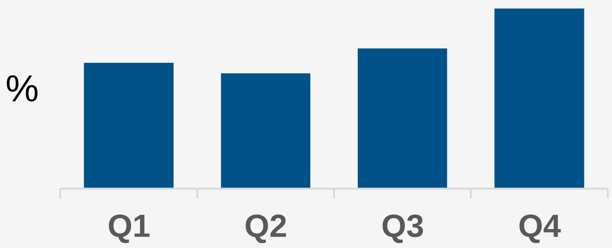
2019 Outlook - EBITDA Profile by Segment

2019 EBITDA[1] Profile[2,3]

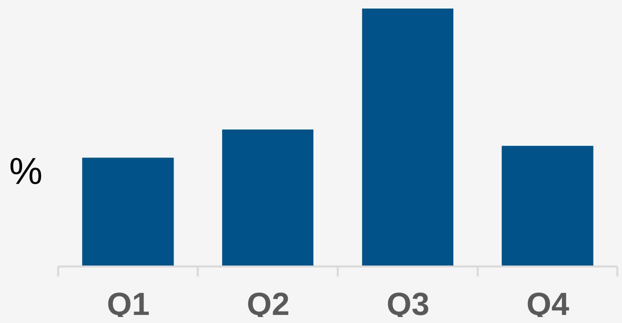
Utilities



Midstream



Power

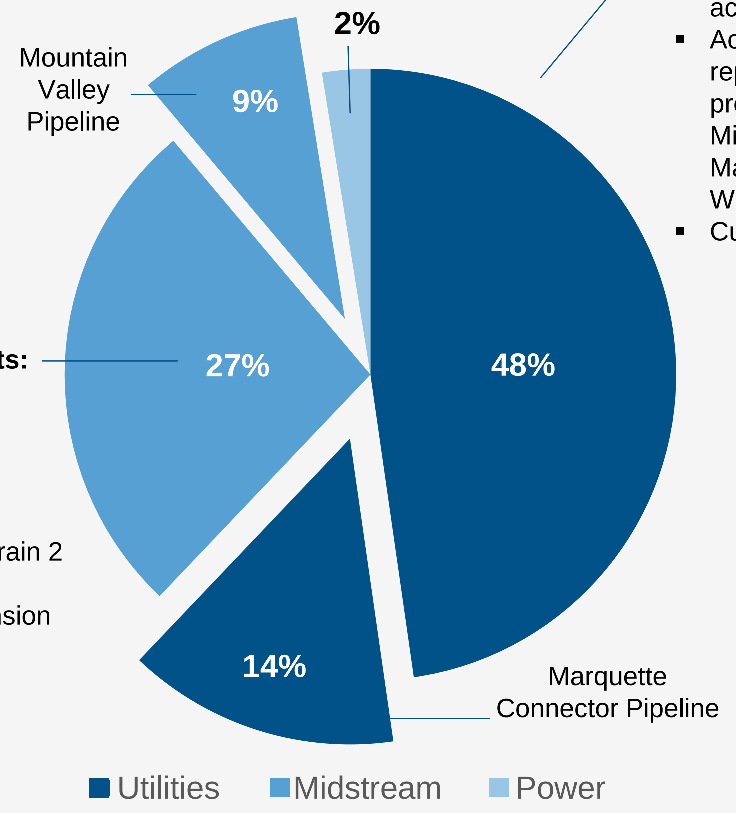


1 Non-GAAP financial measure; see discussion in the advisories See "Forward-looking Information"
2 EBITDA profile includes asset sales announced to-date
3 For illustrative purposes only, actual results may vary

$1.3 Billion Capital Program

Focused on superior near-term returns

~$1.3 Billion Top-Quality Projects, YTD $700 Million Spent



Identified Projects:
- System betterment across all Utilities
- Accelerated pipe replacement programs in Michigan, Virginia, Maryland and Washington D.C.
- Customer growth

Identified Projects:
- RIPET
- Townsend Expansion
- Aitken Creek Development
- North Pine – Train 2
- Central Penn Pipeline Expansion

Capital Allocation Criteria:

- Strong organic growth potential and strategic fit
- Strong risk adjusted returns and near-term contributions to per share FFO[1] and Earnings
- Strong commercial underpinning

1 Non-GAAP financial measure; see discussion in the advisories
See "Forward-looking Information"

Supportive Regulatory Environment for Utilities

Utility	2018 YE Rate Base ($US)	Average Customers	Allowed ROE and Equity Thickness	Regulatory Update
SEMCO Michigan	$472M	303,000	10.35% 49%	▪ Distribution rates approved under cost of service model. ▪ Projected test year used for rate cases with 10 month limit to issue a rate order. ▪ Last rate case settled in 2011. Filed rate case in May 2019; decision expected at the end of Q1 2020. ▪ In August 2017, received approval from the Michigan Public Service Commission for the Act 9 application for the Marquette Connector Pipeline
ENSTAR Alaska	$291M	145,000	11.875% 51.81%	▪ Distribution rates approved under cost of service model using historical test year and allows for known and measurable changes. ▪ Rate Order approving rate increase issued on September 22, 2017. Final rates effective November 1, 2017. ▪ Required to file another rate case no later than June 1, 2021 based upon 2020 test year.
CINGSA Alaska	$77M[1]	ENSTAR, 3 electric utilities and 5 other customers	11.875%[2] 50.00%	▪ Distribution rates approved under cost of service model using historical test year and allows for known and measurable changes. ▪ Rate case filed in 2018 based on 2017 historical test year. ▪ Rate case hearing took place in May 2019 with a decision expected in August 2019.

AltaGas

1 Reflects 65% ownership
2 CINGSA implemented interim rates reflecting an assumed ROE of 11.875% based on a rate case filed in April 2018
See "Forward-looking Information"

Supportive Regulatory Environment for Utilities

Utility	2018 YE Rate Base ($US)	Average Customers	Allowed ROE and Equity Thickness	Regulatory Update
Virginia	$2.8B	531,000	9.50% 52.3%	▪ Distribution rates approved under cost of service model. ▪ Rate case filed in July 31, 2018 seeking rate increase of US$37.6M, including transfer of US$14.7M rider under the Steps to Advance Virginia's Energy Plan ("SAVE") for net increase of US$22.9M; US$1.3B projected rate base based on 10.6% ROE and ~53.3% of equity thickness. WG Rebuttal Testimony filed on April 12th lowered the rate increase to US$33.3M, reflecting acceptance of SCC Staff adjustments and lowering ROE request to 10.3% and increasing equity thickness to 53.5%. Hearing took place in April, expect decision in late 2019.
Maryland		489,000	9.70% 51.7%	▪ Distribution rates approved under cost of service model. ▪ Rates approved in December 2018; US$28.6M in new revenues including transfer of US$15M of Maryland Strategic Infrastructure Development and Enhancement ("STRIDE") costs and increased return on equity to 9.7% ▪ Rate case filed in April 2019, seeking an increase in base rates of US$35.9M, partially offset by a reduction of US$5.1M in surcharges currently paid by customers for system upgrades. Filing proposes a Safety Response Tracker (SRT) that would allow for more timely recovery of actual annual leak management and related costs. Hearing takes place around end of August; final decision expected in November and final rates expected to be effective in December 2019.
Washington D.C.		165,000	9.25% 55.7%	▪ Distribution rates approved under cost of service model. ▪ Last rate case was filed in February 2016 with final rates approved in March 2017. ▪ Rate case to be submitted in 2020.

Accelerated Replacement Program

Utility	Location	Program
SEMCO ENERGY GAS COMPANY	Michigan	▪ Main Replacement Program (MRP) expires in 2020. Rate case filed in May seeks approval for MRP extension for 2021-2025 with total spending to be ~US$60M, and introduction of a new Infrastructure Reliability Improvement Program (IRIP) for 2021-2025 with total capex around US$55M. ▪ Expect to incur MRP capex approximately US$10M in 2019.
Washington Gas A WGL Company	Virginia	▪ Authorized to invest US$500M, including cost of removal over a five-year calendar period ending in 2022. ▪ The SAVE application for 2019 was approved and the rider was implemented beginning January 2019. ▪ Expect to incur approximately US$90M in 2019.
Washington Gas A WGL Company	Maryland	▪ STRIDE renewal approved in 2018 to be US$350M over 5 years (2019-2023) ▪ Expect to incur approximately US$65M in 2019.
Washington Gas A WGL Company	Washington D.C.	▪ PROJECT*pipes* 1 expires September 30, 2019. ▪ PROJECT*pipes 2* for accelerated replacement filed in December 2018 requesting approval of approximately US$305M in accelerated infrastructure replacement in the District of Columbia during the 2019-2024 period. ▪ Seeking commission approval for three-month extension of the current program until the end of 2019 pending PSC decision on PROJECT*pipes* 2. ▪ Expect to incur approximately US$40M in 2019, including three-month extension.