Targa Resources

Investor Presentation

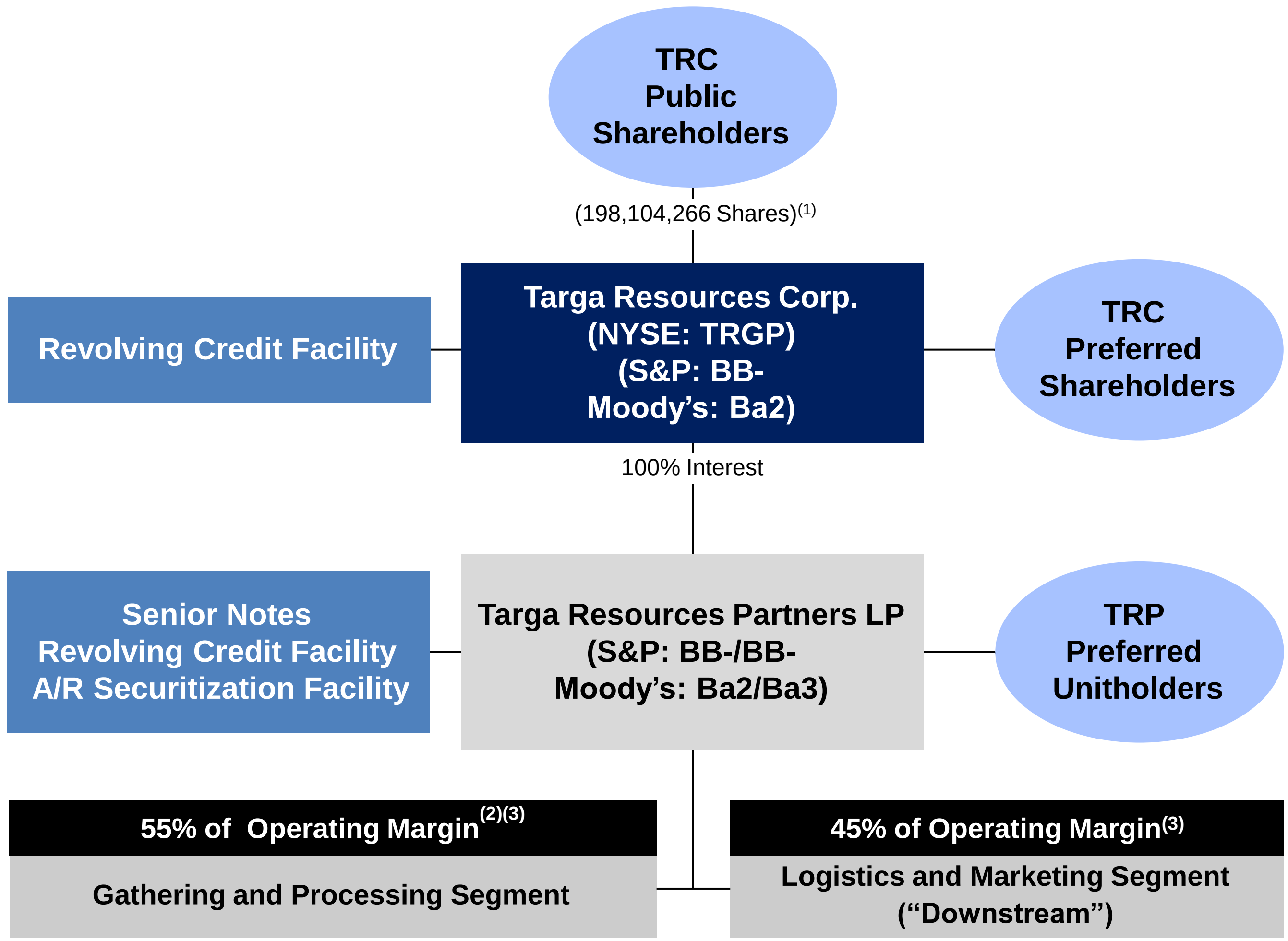
First Quarter 2017

May 4, 2017

Forward Looking Statements

Certain statements in this presentation are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that Targa Resources Corp. (NYSE: TRGP; “Targa”, “TRC” or the “Company”) expects, believes or anticipates will or may occur in the future are forward-looking statements. These forward-looking statements rely on a number of assumptions concerning future events and are subject to a number of uncertainties, factors and risks, many of which are outside the Company’s control, which could cause results to differ materially from those expected by management of Targa Resources Corp. Such risks and uncertainties include, but are not limited to, weather, political, economic and market conditions, including declines in the production of natural gas or in the price and market demand for natural gas and natural gas liquids, the timing and success of business development efforts, the credit risk of customers and other uncertainties. These and other applicable uncertainties, factors and risks are described more fully in the Company’s Annual Report on Form 10-K for the year ended December 31, 2016 and subsequently filed reports with the Securities and Exchange Commission. The Company undertakes no obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

Corporate Structure



(1) Represents shares of our common stock outstanding as of May 1, 2017
(2) Includes the effects of commodity derivative hedging activities
(3) Reflective of trailing twelve months as of March 31, 2017

Strong Asset Base Poised for Growth

A Strong Footprint in Active Basins

- Premier Permian Basin footprint across Midland Basin and Delaware Basin
- Midcontinent position well exposed to SCOOP play and STACK play
- Dedicated acreage across the most attractive counties in the Bakken
- Enhanced Eagle Ford presence through attractive JV with active producer partner

And a Leading Position at Mont Belvieu

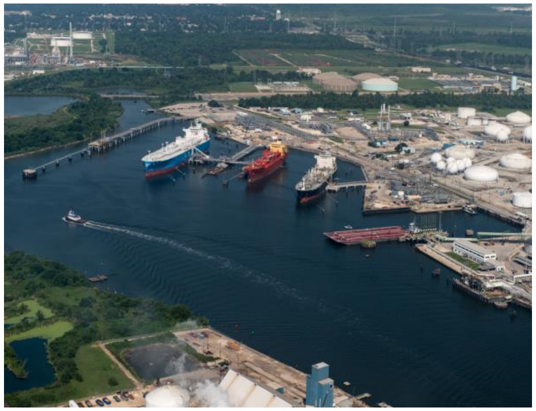
- Premier fractionation ownership position in NGL market hub at Mont Belvieu
- Most flexible LPG export facility along the US Gulf Coast is substantially contracted over the long-term
- Infrastructure network difficult to replicate
- Well-positioned to serve growing Gulf Coast petrochemical complex

Drive Targa's Long-Term Growth

- Well positioned to continue to pursue G&P expansions as producer activity increases
- Adding fractionation over time to support NGL supply increases, "when" not "if"
- Vertically integrated asset position bolsters competitiveness
- Strong balance sheet and demonstrated access to capital markets supports additional growth opportunities

TARGA

Strategic Outlook



- **Increasing producer activity drives the need for additional G&P infrastructure**
  - Adding over 1 Bcf/d of incremental natural gas processing capacity in 2017 and 2018
    - Adding four new plants and 775 MMcf/d of additional Permian processing capacity(1)
    - Adding 260MMcf/d of processing capacity in SouthTX in 2017, supported by JV with Sanchez Energy ("SN") / Sanchez Production Partners ("SPP")
    - Expanding infrastructure to support growing producer activity in the Bakken
    - Building a pipeline in SouthOK to bring additional SCOOP volumes to our system
  - Q1 2017 acquisition of additional Delaware and Midland assets in the Permian augments strong organic growth portfolio
- **Downstream benefits from rising G&P activity, and is also supported by positive long-term demand fundamentals**
  - Additional fractionation volumes from:
    - Greater ethane extraction as new petrochemical facilities come online; and
    - Higher producer activity
  - Excess propane and butanes from expected NGL growth will be exported to clear domestic market
  - Downstream growth capital focused on increasing storage footprint and connectivity to growing petrochemical complex
- **Visibility to invest growth capital in attractive projects in 2017 and beyond**
  - 2017E net growth capital spend of $960 million, based on announced projects
    - $800 million of 2017E net growth capex for G&P projects
    - $160 million of 2017E net growth capex for Downstream projects
  - Additional G&P and Downstream projects under development

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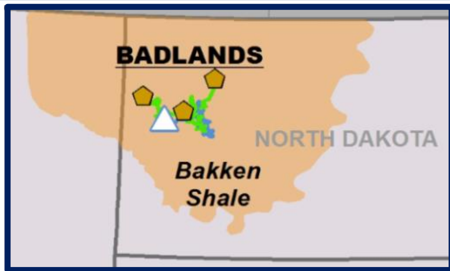
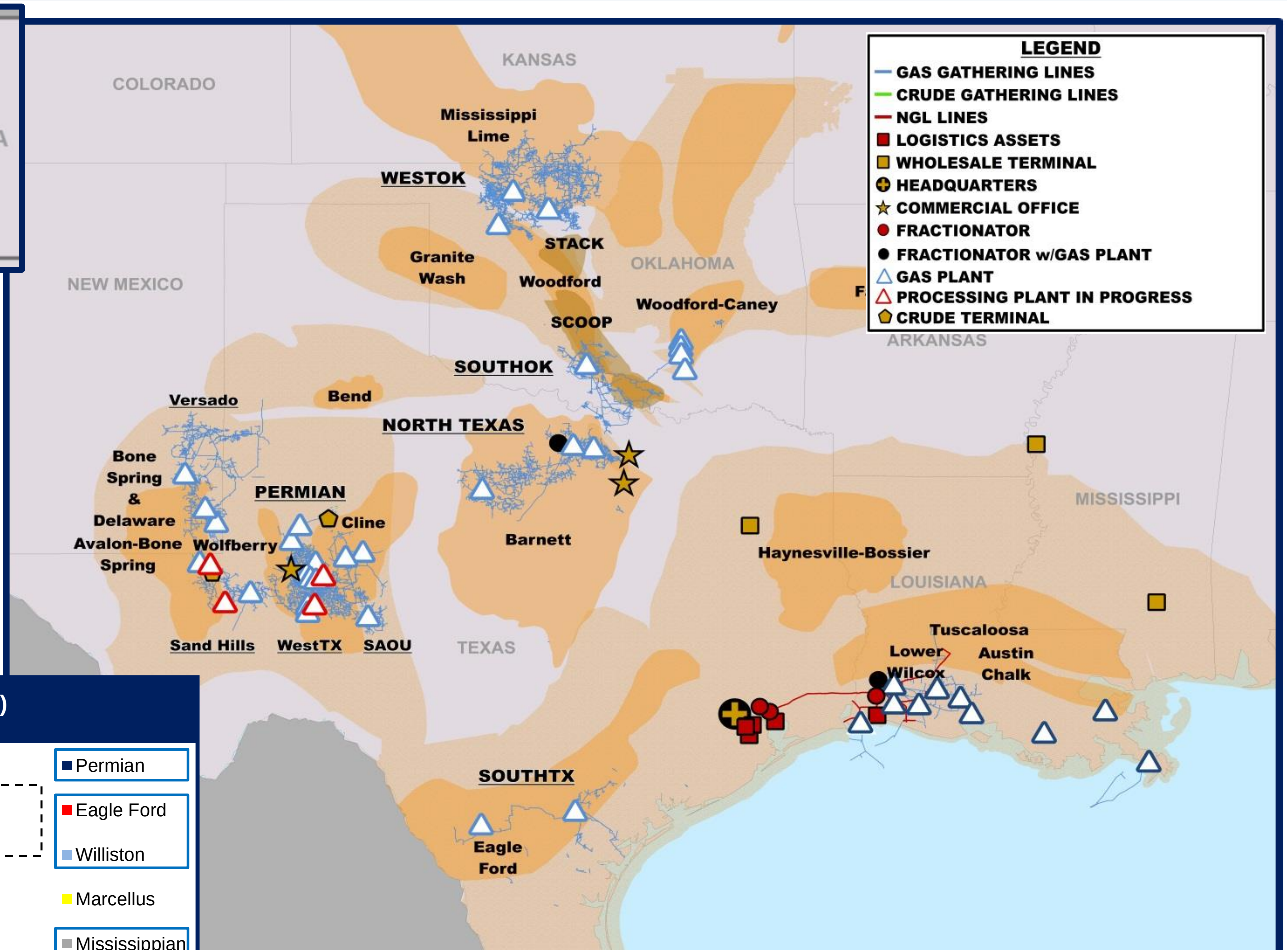
(1) Includes Benedum re-start (online Q1 2017), expansion at Midkiff (expected completion Q2 2017), and Joyce (expected online Q1 2018), Johnson (expected online Q3 2018), Oahu (expected online Q4 2017), and Wildcat (expected online Q3 2018) plants

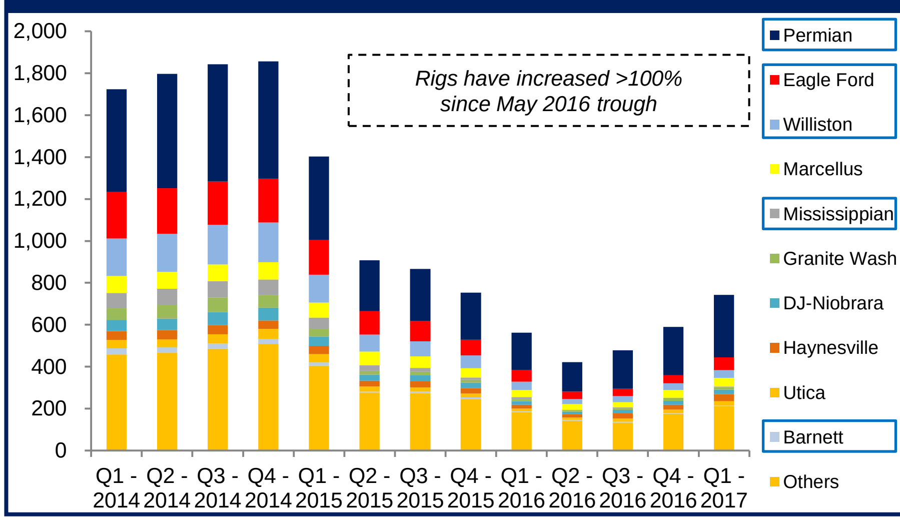
Attractive Asset Footprint



- Targa's assets are positioned in some of the best U.S. basins (Permian - Midland, Permian – Delaware, STACK, SCOOP, Bakken and Eagle Ford)
- Integration of G&P and Downstream assets continued area of focus



U.S. Land Rig Count by Basin[1]



Asset Highlights

- ~9.2 Bcf/d gross processing capacity[2]
- 46 natural gas processing plants[3]
- 5 crude terminals with 145MBbls of storage capacity
- ~ 28,600 miles of natural gas, NGL and crude oil pipelines
- Gross NGL production of ~318 MBbls/d in Q1 2017
- 3 refined products terminals with 2.5 MMBbls of storage
- Over 670 MBbl/d gross fractionation capacity
- 7.0 MMBbl/month or more capacity LPG export terminal

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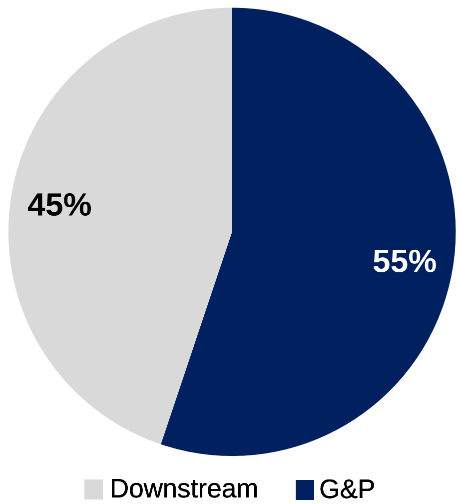
(1) Source: Baker Hughes

(2) Includes: Joyce Plant (200MMcf/d) and Johnson Plant (200MMcf/d) in process in the Midland Basin; Includes Oahu Plant (60MMcf/d) and Wildcat Plant (250MMcf/d) in process in the Delaware Basin; expansion of Raptor Plant (60MMcf/d) in the Eagle Ford

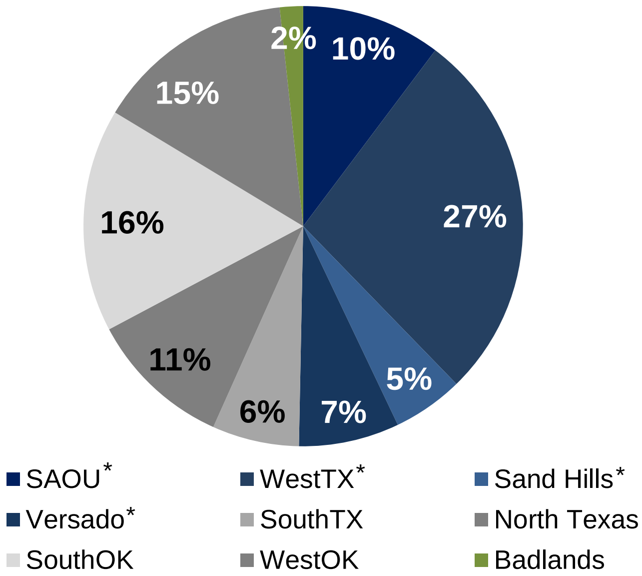
(3) Includes Joyce, Johnson, Oahu, and Wildcat Plants

Business Mix, Diversity and Fee-Based Margin

Business Mix – Operating Margin[1]



Field G&P Diversity – Q1 2017 Natural Gas Inlet Volumes



* *Permian Basin*

Full Service Midstream Provider

- **Targa has developed into a stable, fully-diversified midstream company**
  - Significant margin contributions from both Downstream and G&P segments
  - Diversification across 10+ shale/resource plays
  - Assortment of downstream services provided – fractionation, LPG exports, treating, storage, etc.
- **Vertical integration strengthens competitive advantage**
- **Operating margin is approximately two-thirds fee-based, providing cash flow stability**

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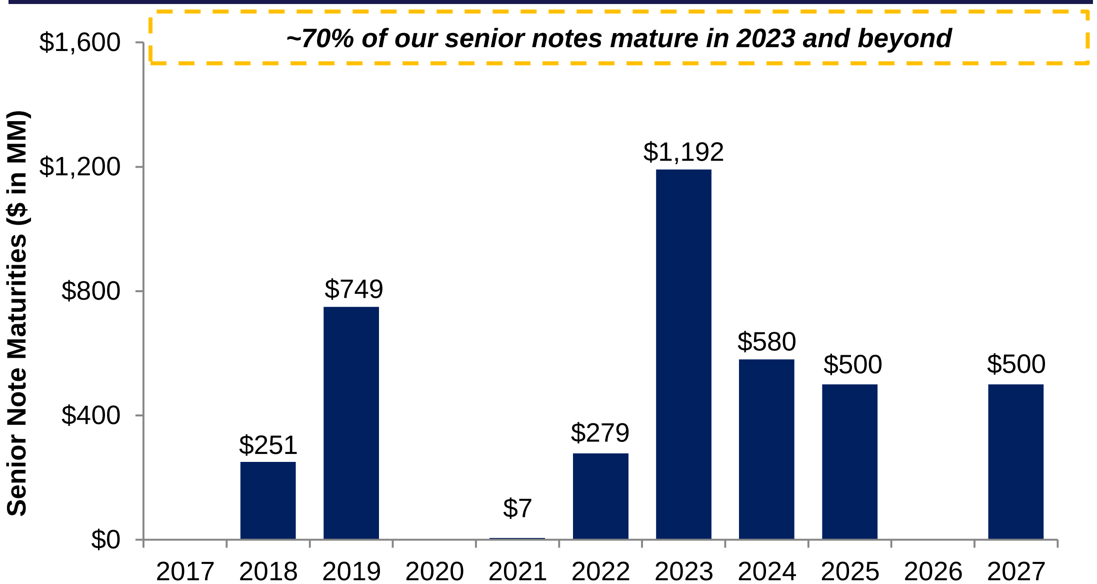
(1) Based on trailing twelve months as of March 31, 2017

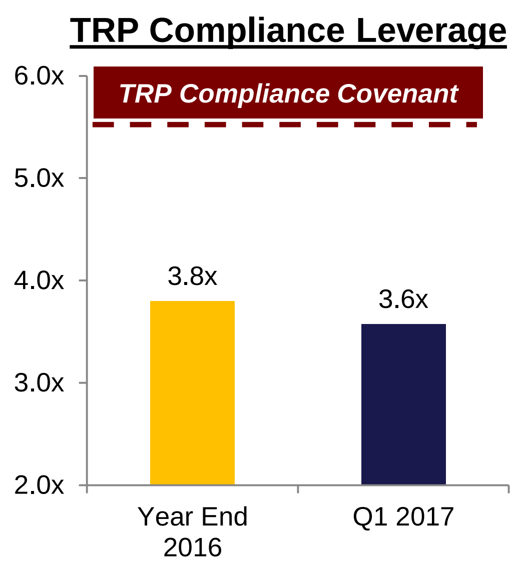
Financial Position and Leverage

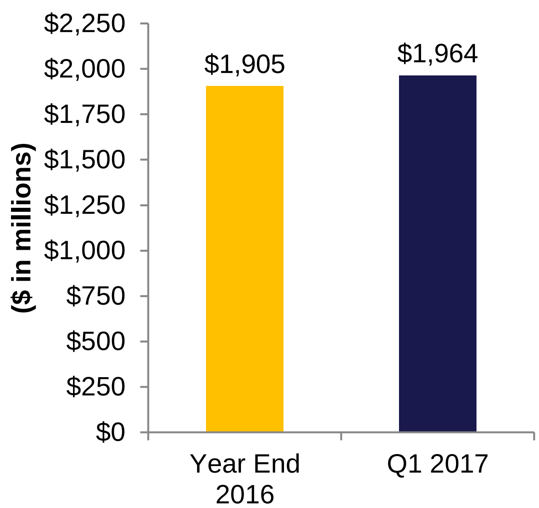
- **Protecting the balance sheet and maintaining balance sheet flexibility remain key objectives**
- **In Q1 2017, repaid $160 million outstanding on TRC Term Loan, using borrowings under TRC credit facility**
- **Strong available liquidity position of ~$2 billion**
- **Proven track record of accessing capital markets to fund growth**
  - Issued ~$1 billion of senior notes at attractive rates to refinance near-term maturities in Q4 2016
  - Raised ~$525 million of public equity in conjunction with the Permian acquisition that closed in Q1 2017
  - Raised ~$238 million of equity through the ATM YTD through April 2017
    - Expect to continue to use the ATM program to fund the equity portion of growth capex

Senior Note Maturities[1]



Pro Forma Leverage and Liquidity



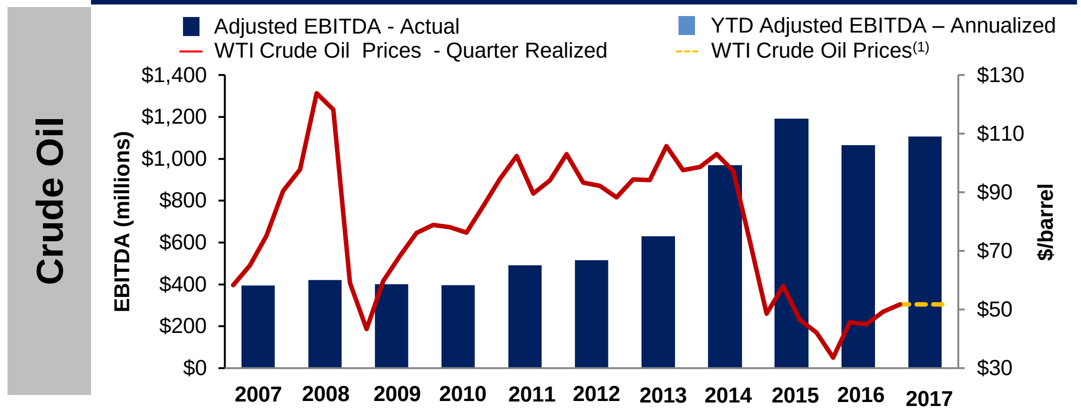


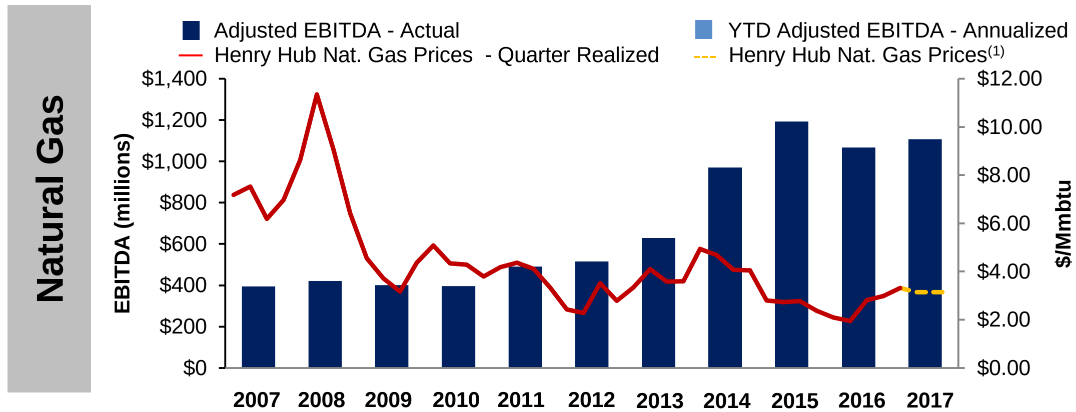
(1) As of March 31, 2017

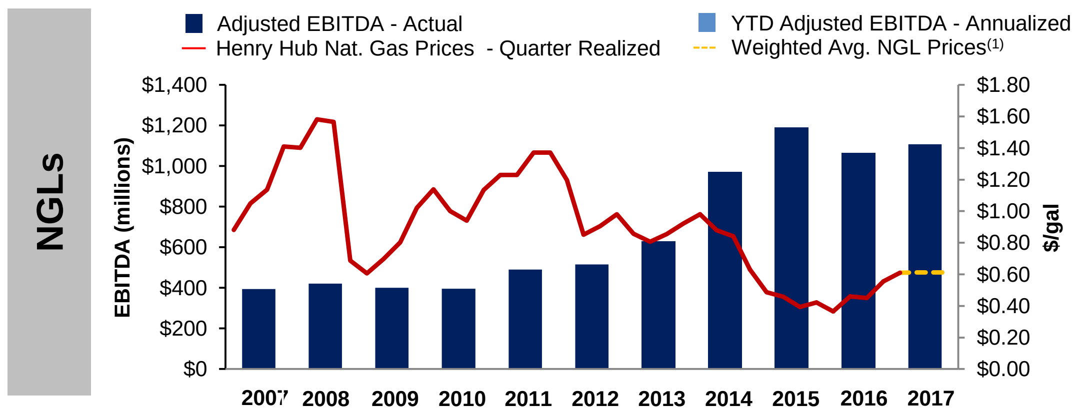
Diversity and Scale Help Mitigate Commodity Price Changes

- **Growth has been driven primarily by investing in the business, not by changes in commodity prices**
- **Targa benefits from multiple factors that help mitigate commodity price volatility, including:**
  - Scale
  - Business and geographic diversity
  - Increasing fee-based margin
  - Hedging
- **Targa is only partially hedged for the balance of 2017 and beyond, and in an environment of rising commodity prices, will benefit**
  - Based on our estimate of <u>current</u> equity volumes, for 2017, approximately 75% of natural gas, 70% of condensate and 60% of NGLs are hedged
  - For 2018, approximately 50% of natural gas, 50% of condensate and 25% of NGLs are hedged
- **Below are commodity price only sensitivities to 2017 Adjusted EBITDA:**
  - +/- $0.05/gal NGLs = +/- $19 million Adjusted EBITDA
  - +/- $0.25/MMBtu nat gas = +/- $2 million Adjusted EBITDA
  - +/- $5.00/Bbl crude oil = +/- $1 million Adjusted EBITDA

Adjusted EBITDA vs. Commodity Prices







(1) *Prices reflect average Q1 2017 prices for WTI crude oil, Henry Hub natural gas, and Mont Belvieu NGLs*

Note: Targa's composite NGL barrel comprises 38% ethane, 34% propane, 5% iso-butane, 12% normal butane, and 11% natural gasoline

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2017 Announced Net Growth Capex

- **With the continued growth in upstream activity around our G&P systems, we now estimate ~$960 million of 2017 net growth capex from the projects outlined below**
  - Adding additional gas processing capacity to our Permian systems including a new 250 MMcf/d plant in the Delaware Basin and a new 200 MMcf/d plant in the Midland Basin
  - Also currently expect to spend $350 million on additional gas and crude gathering infrastructure in the Permian
  - Continuing to expand Badlands Bakken infrastructure in North Dakota
- **Continue to pursue additional attractive growth opportunities which likely result in additional 2017 announced projects and capital expenditures**

($ in millions)	Location	Total Project Capex	2017E Capex	Expected Completion	Primarily Fee-Based
200 MMcf/d WestTX Joyce Plant and Related Infrastructure[1]	Permian - Midland	90	65	Q1 2018	
200 MMcf/d WestTX Johnson Plant and Related Infrastructure[1]	Permian - Midland	90	30	Q3 2018	
60 MMcf/d Oahu Plant and Related Infrastructure	Permian - Delaware	40	40	Q4 2017	✓
250 MMcf/d Wildcat Plant and Related Infrastructure	Permian - Delaware	130	80	Q3 2018	✓
Other Permian - (additional gas and crude gathering infrastructure)[1]	Permian - Midland	200	200	2017	
Other Permian - (additional gas and crude gathering infrastructure)	Permian - Delaware	150	150	2017	✓
Total Permian	**Permian**	**$700**	**$565**		
SouthTX Sanchez Energy JV[1]	Eagle Ford	100	20	2017	✓
Central (additional gas gathering infrastructure)[1]	Central	65	65	2017	
Total Central	**Eagle Ford, STACK, SCOOP**	**$165**	**$85**		
Total Badlands	**Bakken**	**$150**	**$150**	**2017**	✓
Total - Gathering and Processing		**$1,015**	**$800**		
Crude and Condensate Splitter	Channelview	140	70	Q1 2018	✓
Downstream Other Identified Spending	Mont Belvieu	90	90	2017	✓
Total - Downstream		**$230**	**$160**		✓
Total Net Growth Capex		**$1,245**	**$960**		

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(1) Represents net capex based on Targa's effective ownership interest

Operational and Financial Expectations

LPG Export Contracts at Galena Park	◆ **Substantially contracted over the long term at attractive rates** ◆ Expect a mix of long-term and short-term volumes moving across our dock, proving potential for volume upside beyond contracted volumes
2017E Field G&P Volumes	◆ **2017E Field G&P nat gas inlet volumes expected to average at least 10% higher than 2016 Field G&P average natural gas inlet volumes** ◆ In the Permian Basin, we expect average G&P natural gas inlet volumes to increase by approximately 20% in 2017 compared to 2016 ❖ Includes volumes from acquisition of assets in the Delaware and Midland Basins ◆ Expect higher natural gas inlet volumes in SouthTX average 2017 versus average 2016 ◆ Expect higher natural gas inlet volumes and crude volumes in the Badlands average 2017 versus average 2016 ❖ These inlet volume increases will be partially offset by lower volumes in WestOK, SouthOK and North Texas
2017E Capex	◆ **2017E net growth capex of $960 for current identified spending** ◆ Continue to pursue additional attractive growth opportunities ◆ **2017E net maintenance capex of approximately $110 million**
2017E Financial Outlook	◆ **Expect Q4 2017 Operating Margin for G&P and Downstream segments to be highest of the year** ◆ **For full year 2017, expect dividend coverage to be 1.0 times or better** ◆ Assumes $3.64 per common share 2017 dividend ◆ Expect dividend coverage to trough in Q2, and increase in Q3 and Q4
Cash Taxes	◆ **Do not expect to pay cash taxes for the next 5 years**

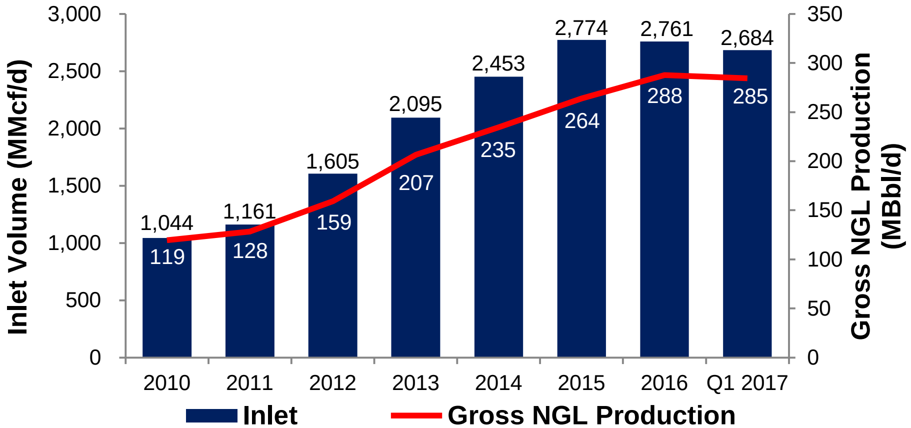
Attractive Asset Footprint

Extensive Field Gathering and Processing Position

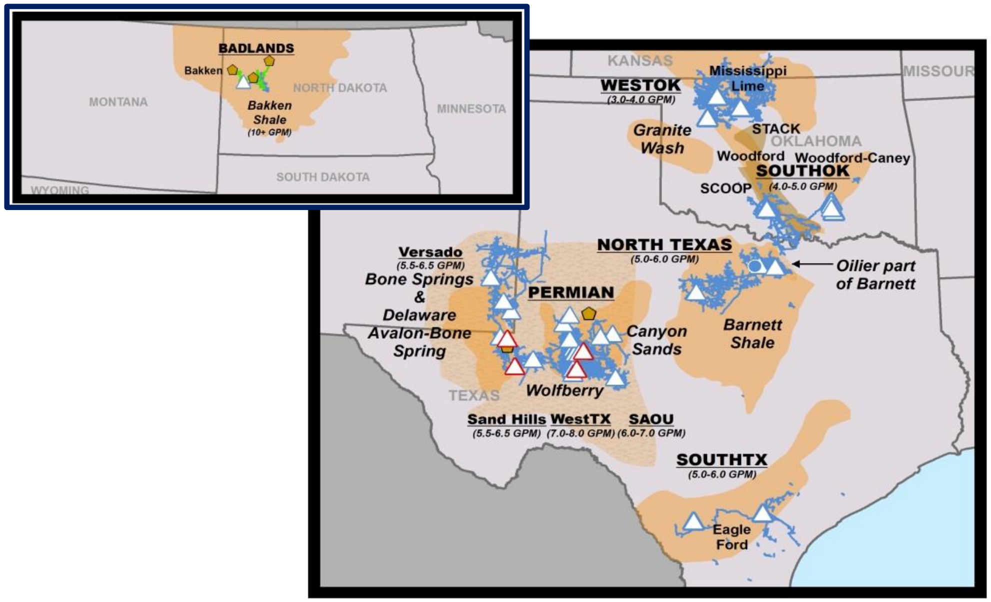
Summary

- **Over 26,000 miles of pipeline across attractive positions**
- **~4.7 Bcf/d of gross processing capacity[(2)(3)(4)]**
- **Acquired additional Delaware and Midland Basin assets on March 1, 2017**
- **G&P capacity additions underway:**
  - 730 MMcf/d of additional processing capacity additions underway in the Permian Basin
  - 60 MMcf/d processing capacity expansion underway in the Eagle Ford
- **Recently completed G&P capacity additions:**
  - Added a 200 MMcf/d plant in Q2 2016 (Midland Basin)
  - Re-started a 45 MMcf/d plant in Q1 2017 (Midland Basin)
  - Initiating start-up of a new 200 MMcf/d plant (Eagle Ford)
- **Mix of POP and fee-based contracts**

Volumes[(1)]



Footprint

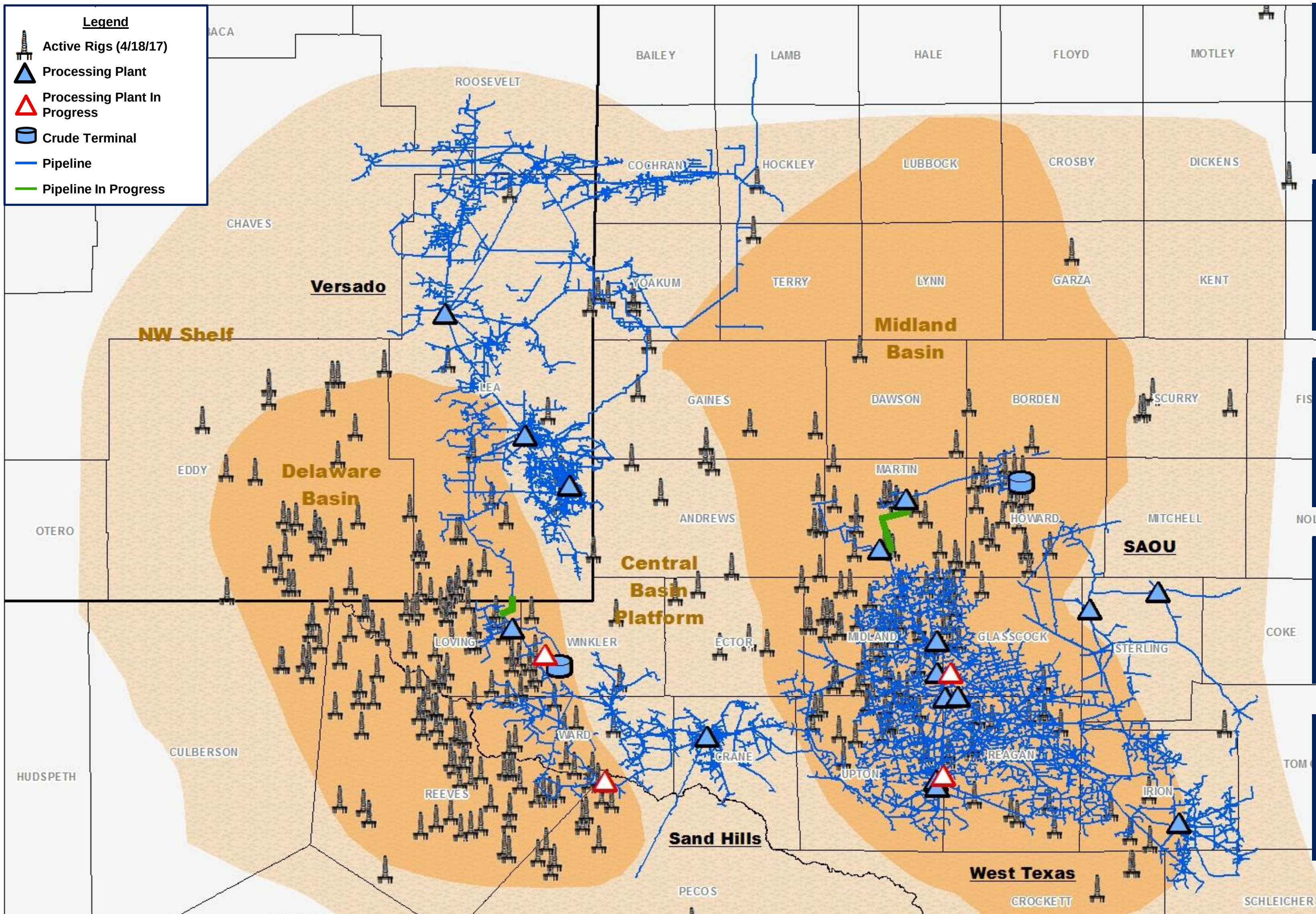


	Est. Gross Processing Capacity (MMcf/d)	Miles of Pipeline[(5)]
Permian - Midland[(2)]	1,654	6,300
Permian - Delaware[(3)]	800	5,365
Permian Total	**2,454**	**11,665**
SouthTX[(4)]	660	940
North Texas	478	4,695
SouthOK	580	2,280
WestOK	458	6,450
Central Total	**2,176**	**14,365**
Badlands	90	610
Total	**4,720**	**26,640**

(1) Pro forma Targa/TPL for all years
(2) Includes the Joyce Plant (expected online Q1 2018), the Johnson Plant (expected online Q3 2018), and the Midkiff Plant expansion (expected completion Q2 2017)
(3) Includes the Oahu Plant (expected online Q4 2017) and Wildcat Plant (expected online Q3 2018)
(4) Includes 60 MMcf/d Raptor Plant capacity expansion (expected completion Q3 2017)
(5) Total natural gas, NGL and crude oil pipeline mileage

TARGA

Premier Permian Position



~2 million dedicated acres from a diverse group of producers

~2.5 Bcf/d[1] of total natural gas processing capacity by Q3 2018

Connected recently acquired Delaware Basin assets to Sand Hills in Q1 2017

Expect to connect recently acquired Midland Basin assets to WestTX in Q3 2017

Expect to connect Sand Hills to Versado in 2H 2017

Permian systems expected to be fully connected by end of 2017, adding significant flexibility and operational synergies

TARGA

Source: Drillinginfo; rigs as of April 18, 2017

(1) Includes the Joyce Plant (expected online Q1 2018), the Johnson Plant (expected online Q3 2018), the Midkiff Plant expansion (expected completion Q2 2017), the Oahu Plant (expected online Q4 2017) and the Wildcat Plant (expected online Q3 2018)

Permian – Midland Summary (WestTX and SAOU systems)

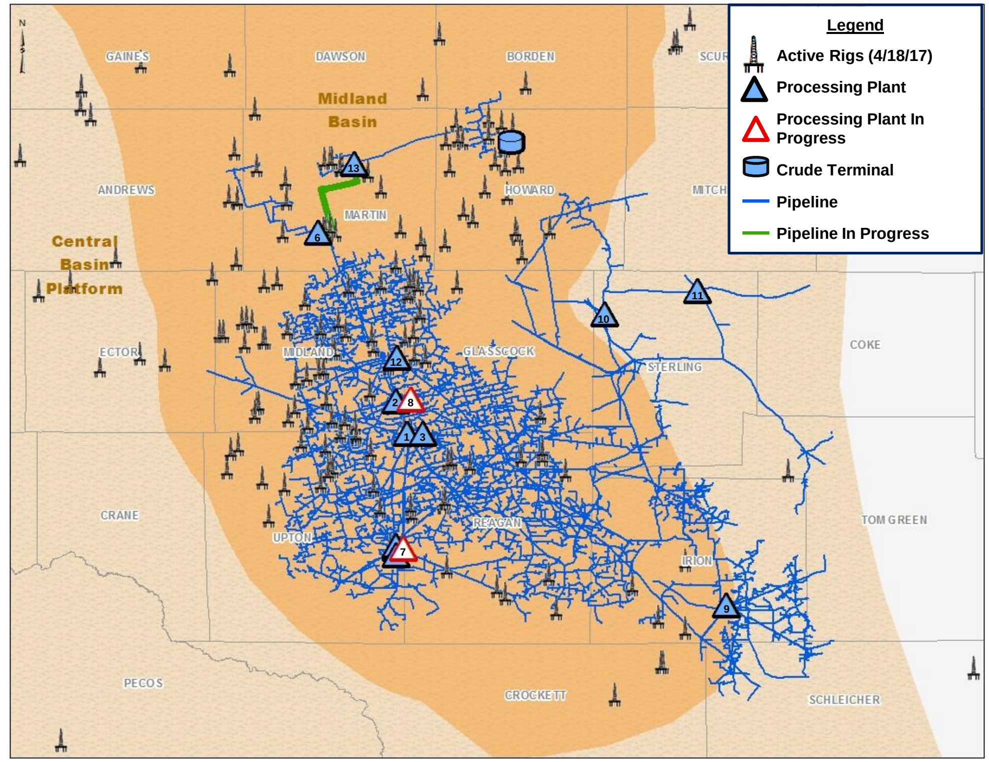
Summary

- **WestTX and SAOU systems located across the core of the Midland Basin**
- **Operate natural gas gathering and processing and crude gathering assets**
- **JV between Targa (72.8% ownership and operator) and PXD (27.2% ownership) in WestTX**
- **Traditionally POP contracts, with added fees and fee-based services for compression, treating, etc.**
- **Contracts acquired as part of Permian acquisition in Q1 2017 are fee-based**

Facility	% Owned	Location (County)	Est. Gross Processing Capacity (MMcf/d)	Q1 2017 Gross Plant Inlet (MMcf/d)	Q1 2017 Gross NGL Production (MBbl/d)	March 2017 Crude Oil Gathered (MBbl/d)	Miles of Pipeline
(1) Consolidator	72.8%	Midland, TX	150				
(2) Driver	72.8%	Midland, TX	200				
(3) Midkiff[a]	72.8%	Reagan, TX	80				
(4) Benedum	72.8%	Upton, TX	45				
(5) Edward	72.8%	Upton, TX	200				
(6) Buffalo	72.8%	Martin, TX	200				
(7) Joyce[b]	72.8%	Upton, TX	200				
(8) Johnson[c]	72.8%	Midland, TX	200				
WestTX Total			**1,275**	**737**	**96**		**4,440**
(9) Mertzon	100.0%	Irion, TX	52				
(10) Sterling	100.0%	Sterling, TX	92				
(11) Conger[d]	100.0%	Sterling, TX	25				
(12) High Plains	100.0%	Midland, TX	200				
(13) Tarzan[e]	100.0%	Martin, TX	10				
SAOU Total			**379**	**276**	**33**		**1,860**
Permian Midland Total[f][g][h]			**1,654**	**1,013**	**129**	**27**	**6,300**

[a] Adding compression to increase capacity to 80 MMcf/d effective Q2 2017
[b] Expected to be completed by Q1 2018
[c] Expected to be completed by Q3 2018
[d] Idled in September 2014
[e] Permian acquisition (closed on March 1, 2017)
[f] Total estimated gross capacity by Q3 2018
[g] Crude oil gathered includes Permian - Midland and Permian - Delaware
[h] Total gas and crude oil pipeline mileage

Asset Map and Rig Activity[1]



Projects Underway or Recently Completed in WestTX

- **Additional 20 MMcf/d of capacity at Midkiff Plant expected complete in Q2 2017**
- **Connection of recently acquired Midland assets to WestTX expected Q3 2017**
- **200 MMcf/d Joyce Plant expected online in Q1 2018 and 200 MMcf/d Johnson Plant expected online in Q3 2018**
- **45 MMcf/d Benedum Plant in WestTX re-started in Q1 2017**
- **200 MMcf/d Buffalo Plant placed in service Q2 2016**

TARGA *(1) Source: Drillinginfo; rigs as of April 18, 2017*

Permian – Delaware Summary (Versado and Sand Hills systems)

Summary

- Versado and Sand Hills capturing growing production from increasingly active Delaware Basin
- Operate natural gas gathering and processing and crude gathering assets
- Traditionally POP contracts, with added fees and fee-based services for compression, treating, etc.
- Contracts acquired as part of Permian acquisition in Q1 2017 are fee-based

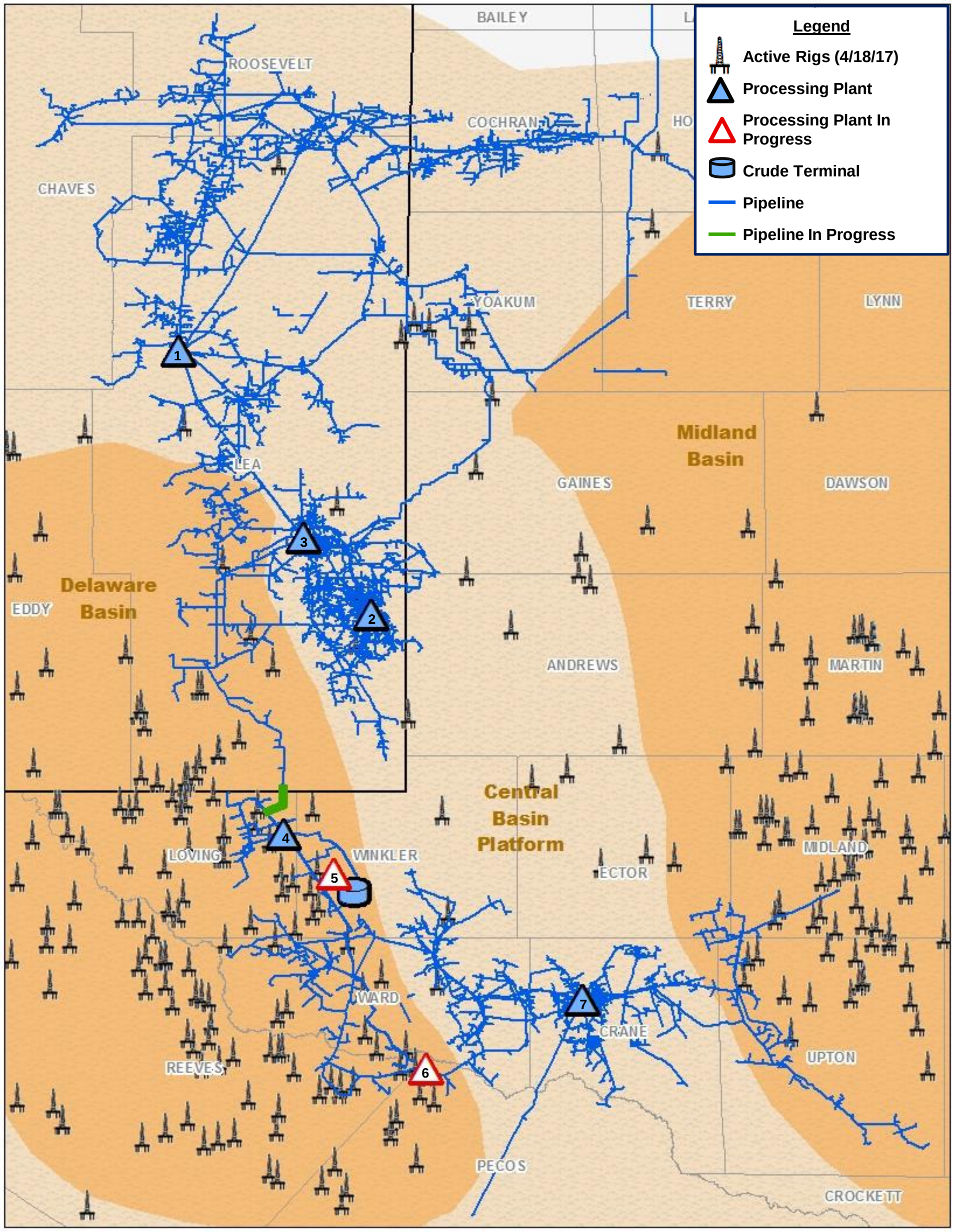
Projects Underway or Recently Completed

- Connected recently acquired Delaware assets to Sand Hills in Q1 2017
- Connection of Versado to Sand Hills expected 2H 2017
- 60 MMcf/d Oahu Plant expected online in Q4 2017
- 250 MMcf/d Wildcat Plant expected online in Q3 2018

Facility	% Owned	Location (County)	Est. Gross Processing Capacity (MMcf/d)	Q1 2017 Gross Plant Inlet (MMcf/d)	Q1 2017 Gross NGL Production (MBbl/d)	March 2017 Crude Oil Gathered (MBbl/d)	Miles of Pipeline
(1) Saunders	100.0%	Lea, NM	60				
(2) Eunice	100.0%	Lea, NM	110				
(3) Monument	100.0%	Lea, NM	85				
Versado Total			**255**	**199**	**23**		**3,615**
(4) Loving Plant[a]	100.0%	Loving, TX	70				
(5) Wildcat[b]	100.0%	Winkler, TX	250				
(6) Oahu[c]	100.0%	Pecos, TX	60				
(7) Sand Hills	100.0%	Crane, TX	165				
Sand Hills Total			**545**	**140**	**15**		**1,750**
Permian Delaware Total[d][e][f]			**800**	**338**	**38**	**27**	**5,365**

[a] Permian acquisition (closed on March 1, 2017)
[b] Expected to be completed by Q3 2018
[c] Expected to be completed by Q4 2017
[d] Total estimated gross capacity by Q3 2018
[e] Crude oil gathered includes Permian - Midland and Permian - Delaware
[f] Total gas and crude oil pipeline mileage

Asset Map and Rig Activity(1)



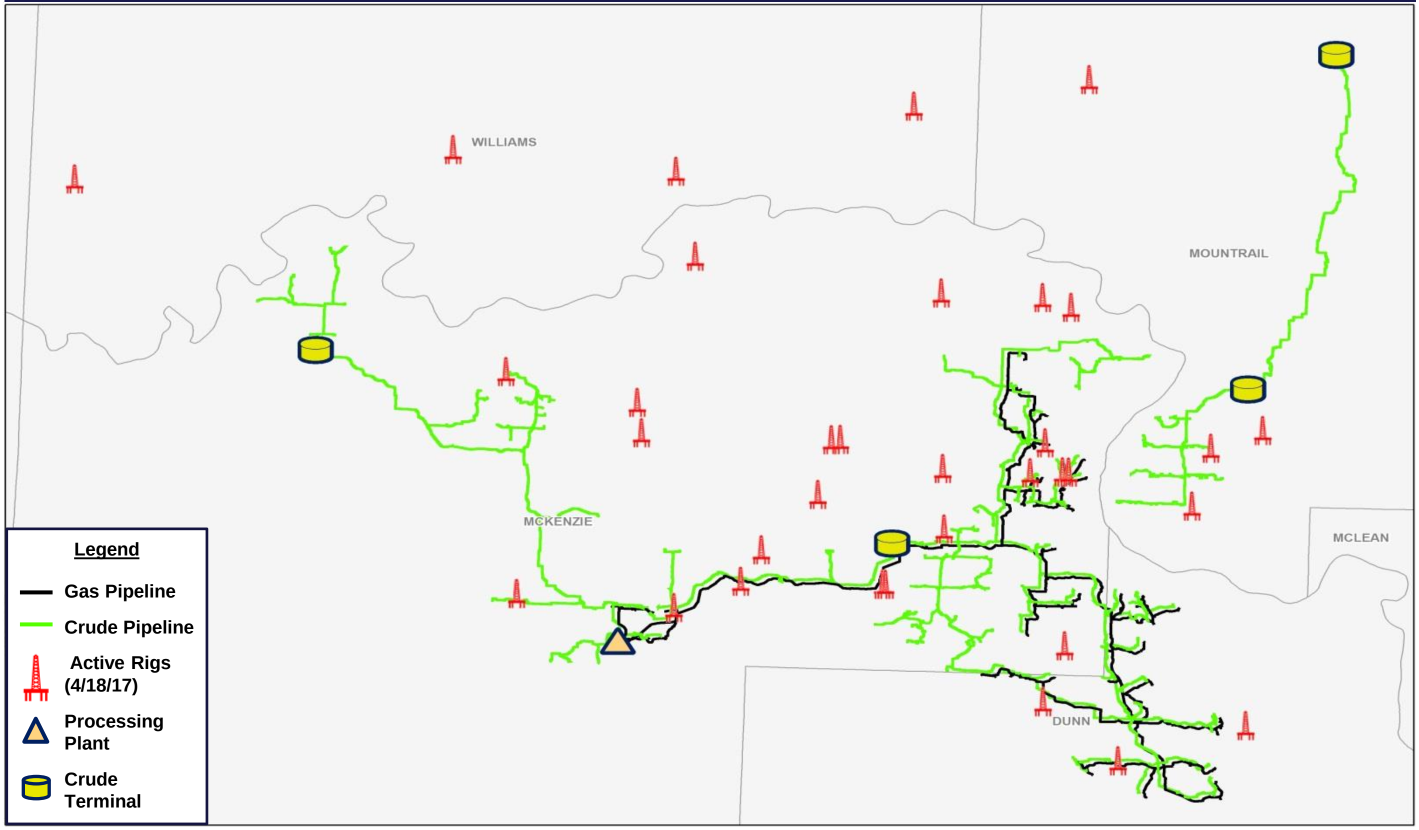
TARGA (1) *Source: Drillinginfo; rigs as of April 18, 2017*

Strategic Position in the Core of the Williston Basin

Summary

- **Core position in McKenzie, Dunn and Mountrail counties**
- **410 miles of crude gathering pipelines**
- **200 miles of natural gas gathering pipelines**
- **90 MMcf/d of total natural gas processing capacity**
  - Three plants at one location
- **Fee-based contracts**
- **Large acreage dedications and AMIs from multiple producers**
- **Current crude oil delivery points include Four Bears, Tesoro, Tesoro BakkenLink, Hilands, and Enbridge**
  - Expect to connect to Dakota Access Pipeline (DAPL) in Q2 2017

Asset Map and Rig Activity(1)



Facility	% Owned	Location (County)	Est. Gross Processing Capacity (MMcf/d)	Q1 2017 Gross Plant Inlet (MMcf/d)	Q1 2017 Crude Oil Gathered (MBbl/d)	Miles of Pipeline
Little Missouri I	100.0%	McKenzie, ND				
Little Missouri II	100.0%	McKenzie, ND				
Little Missouri III	100.0%	McKenzie, ND				
Badlands Total(a)			**90**	**46**	**114**	**610**

TARGA (1) *Source: Drillinginfo; rigs as of April 18, 2017*

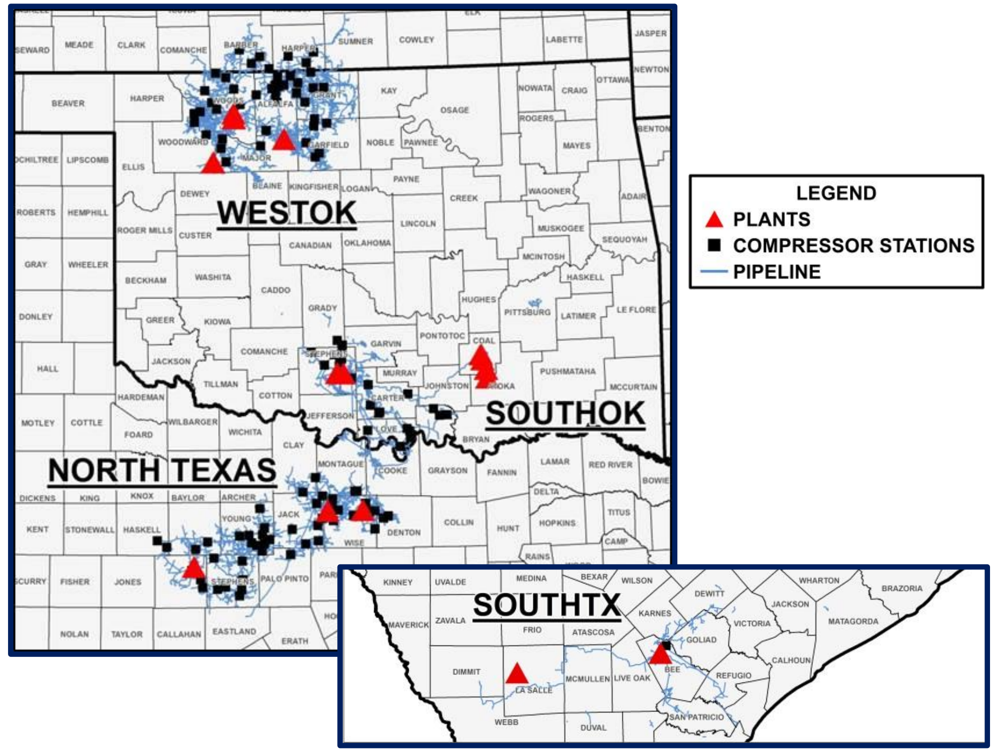
Leading Oklahoma, North Texas and South Texas Positions

Summary

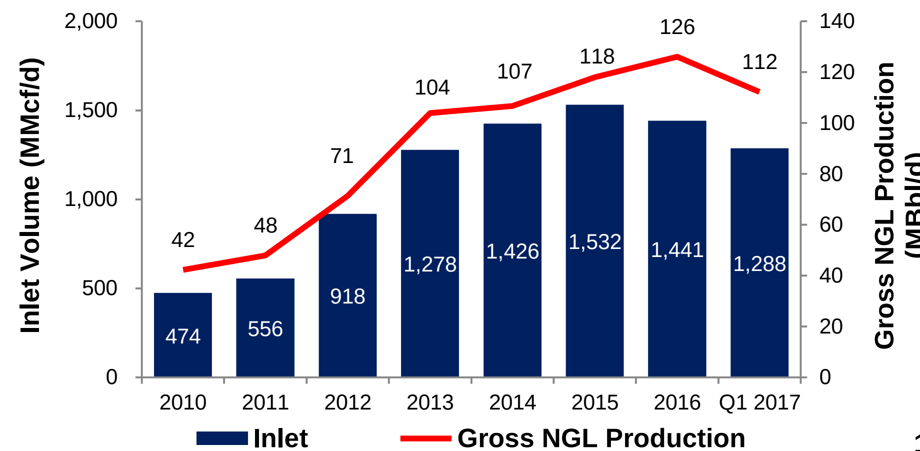
- **Four asset regions which include approximately 14,000 miles of pipeline**
- **Over 2.1 Bcf/d of gross processing capacity[2]**
  - 15 processing plants across the liquids-rich Anadarko Basin (including SCOOP and STACK), Arkoma Basin, Ardmore Basin, Barnett Shale, and Eagle Ford Shale
  - Expanding processing capacity in the Eagle Ford Basin through JV with Sanchez Production Partners (NYSE:SPP)
  - Reviewing opportunities to connect / optimize North Texas and SouthOK systems to enhance reliability, optionality and efficiency for producers
- **Traditionally POP contracts in North Texas and WestOK with additional fee-based services for gathering, compression, treating, etc.**
- **Essentially all of SouthTX and vast majority of SouthOK contracts are fee-based**

	Gross Processing Capacity (MMcf/d)	Miles of Pipeline
WestOK	458	6,450
SouthOK	580	2,280
North Texas	478	4,695
SouthTX[1]	660	940
Central Total	**2,176**	**14,365**

Footprint



Volumes[2]



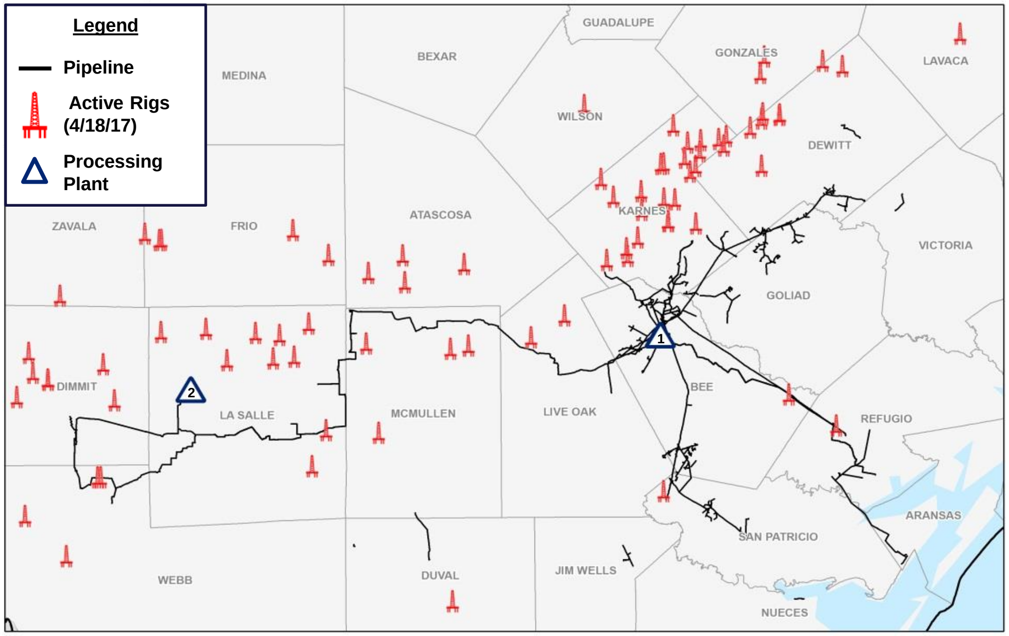
(1) *Includes 60 MMcf/d Raptor Plant expansion*
(2) *Pro forma Targa/TPL for all years*

SouthTX – Sanchez Energy Corp. JV Driving Growth

Summary

- **JV agreements with Sanchez Energy Corp. (NYSE:SN) executed in October 2015**
  - Gathering JV interest subsequently acquired by Sanchez Production Partners LP (NYSE:SPP) in July 2016 and plant JV interest sold to SPP in October 2016
  - Fee-based contracts supported by:
    - 15 year acreage dedication from SN in Dimmit, La Salle and Webb counties
    - 125 MMcf/d 5 year MVC from SN effective once Raptor Plant is online
- **200 MMcf/d Raptor plant mechanically complete and initiating start-up**
  - Adding 60 MMcf/d of capacity to Raptor Plant expected to be complete in Q3 2017
- **Non-JV contracts also fee-based**

Asset Map and Rig Activity(1)



Facility	% Owned	Location (County)	Est. Gross Processing Capacity (MMcf/d)	Q1 2017 Gross Plant Inlet (MMcf/d)	Q1 2017 Gross NGL Production (MBbl/d)	Miles of Pipeline
(1) Silver Oak I	100.0%	Bee, TX	200			
(1) Silver Oak II	90.0%	Bee, TX	200			
(2) Raptor[a]	50.0%	Bee, TX	260			
SouthTX Total			**660**	**172**	**17**	**940**

[a] Expansion to 260MMcf/d expected to be completed in Q3 2017

North Texas – Exposed to Barnett Shale and Marble Falls

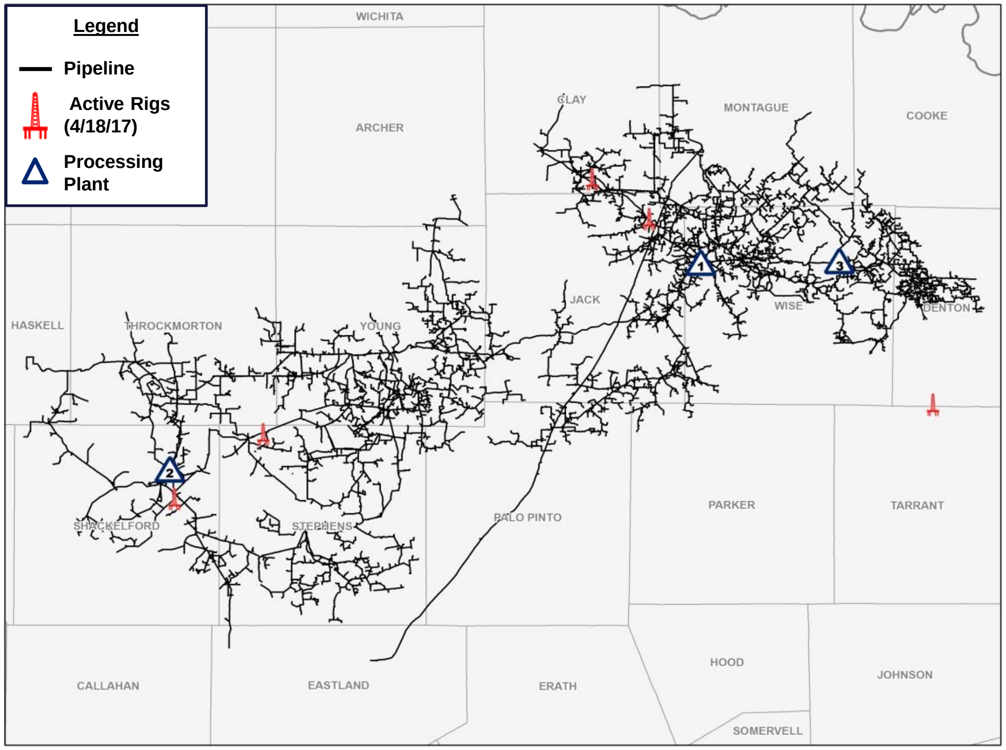
Summary

- **478 MMcf/d of gross processing capacity**
- **Primarily Barnett Shale and Marble Falls**
- **Customers are a combination of larger independent producers with exposure to multiple plays and smaller independents with a single footprint**
- **Primarily POP contracts with fee-based components**
- **May connect North Texas and SouthOK systems in the future to utilize available North Texas capacity**

Facility	% Owned	Location (County)	Est. Gross Processing Capacity (MMcf/d)	Q1 2017 Gross Plant Inlet (MMcf/d)	Q1 2017 Gross NGL Production (MBbl/d)	Miles of Pipeline
(1) Chico[a]	100.0%	Wise, TX	265			
(2) Shackelford	100.0%	Shackelford, TX	13			
(3) Longhorn	100.0%	Wise, TX	200			
North Texas Total			**478**	**283**	**32**	**4,695**

[a] Chico Plant has fractionation capacity of ~15 Mbbls/d

Asset Map and Rig Activity[1]



SouthOK – Exposure to Increasing SCOOP Activity

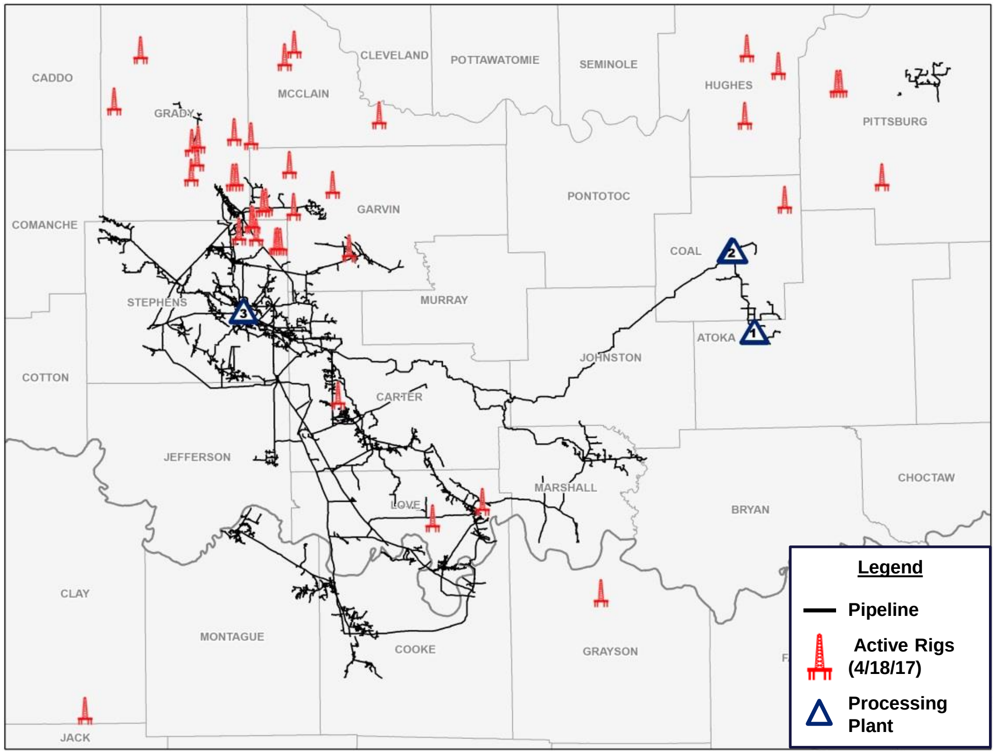
Summary

- **580 MMcf/d of gross processing capacity**
- **System well positioned to benefit from increasing SCOOP activity**
  - Currently building a line to benefit from additional SCOOP volumes in 2H 2017
  - Primary growth driver will be SCOOP activity focused in the oil/condensate window (Grady, Garvin and Stephens Counties)
  - Arkoma Woodford (Coal, Atoka, Hughes and Pittsburg Counties) growth may occur with improvement in gas pricing
- **Majority fee-based contracts**

Facility	% Owned	Location (County)	Est. Gross Processing Capacity (MMcf/d)	Q1 2017 Gross Plant Inlet (MMcf/d)	Q1 2017 Gross NGL Production (MBbl/d)	Miles of Pipeline
(1) Atoka[a]	60.0%	Atoka County, OK	20			
(2) Coalgate	60.0%	Coal, OK	80			
(2) Stonewall	60.0%	Coal, OK	200			
(2) Tupelo	100.0%	Coal, OK	120			
(3) Velma	100.0%	Stephens, OK	100			
(3) Velma V-60	100.0%	Stephens, OK	60			
SouthOK Total			**580**	**440**	**41**	**2,280**

[a] The Atoka Plant was idled due to the start-up of the Stonewall Plant in May 2014

Asset Map and Rig Activity[1]



(1) Source: Drillinginfo; rigs as of April 18, 2017

WestOK – Positioned for STACK Growth

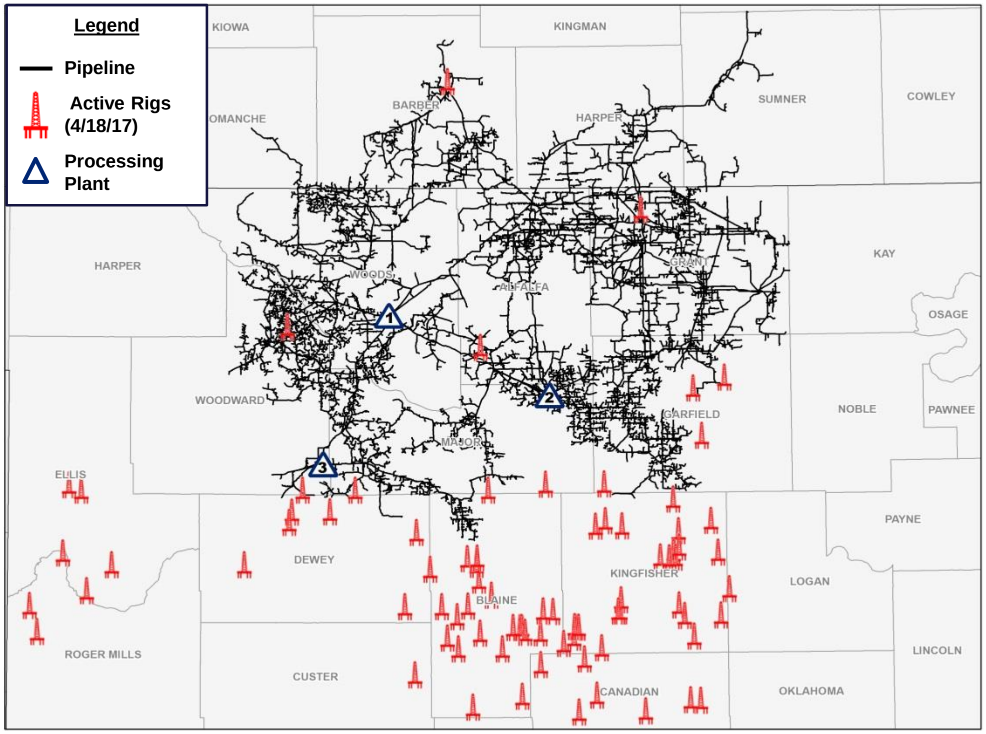
Summary

- ~460 MMcf/d of gross processing capacity
- Positioned to benefit from the continued northwest movement of upstream activity targeting the STACK
- Focused on opportunities to gather volumes further south in Woodward, Dewey, Blaine and Kingfisher counties
- Majority of WestOK contracts are hybrid POP's plus fees

Facility	% Owned	Location (County)	Est. Gross Processing Capacity (MMcf/d)	Q1 2017 Gross Plant Inlet (MMcf/d)	Q1 2017 Gross NGL Production (MBbl/d)	Miles of Pipeline
(1) Waynoka I	100.0%	Woods, OK	200			
(1) Waynoka II	100.0%	Woods, OK	200			
(2) Chaney Dell[a]	100.0%	Major, OK	30			
(3) Chester	100.0%	Woodward, OK	28			
WestOK Total			**458**	**393**	**23**	**6,450**

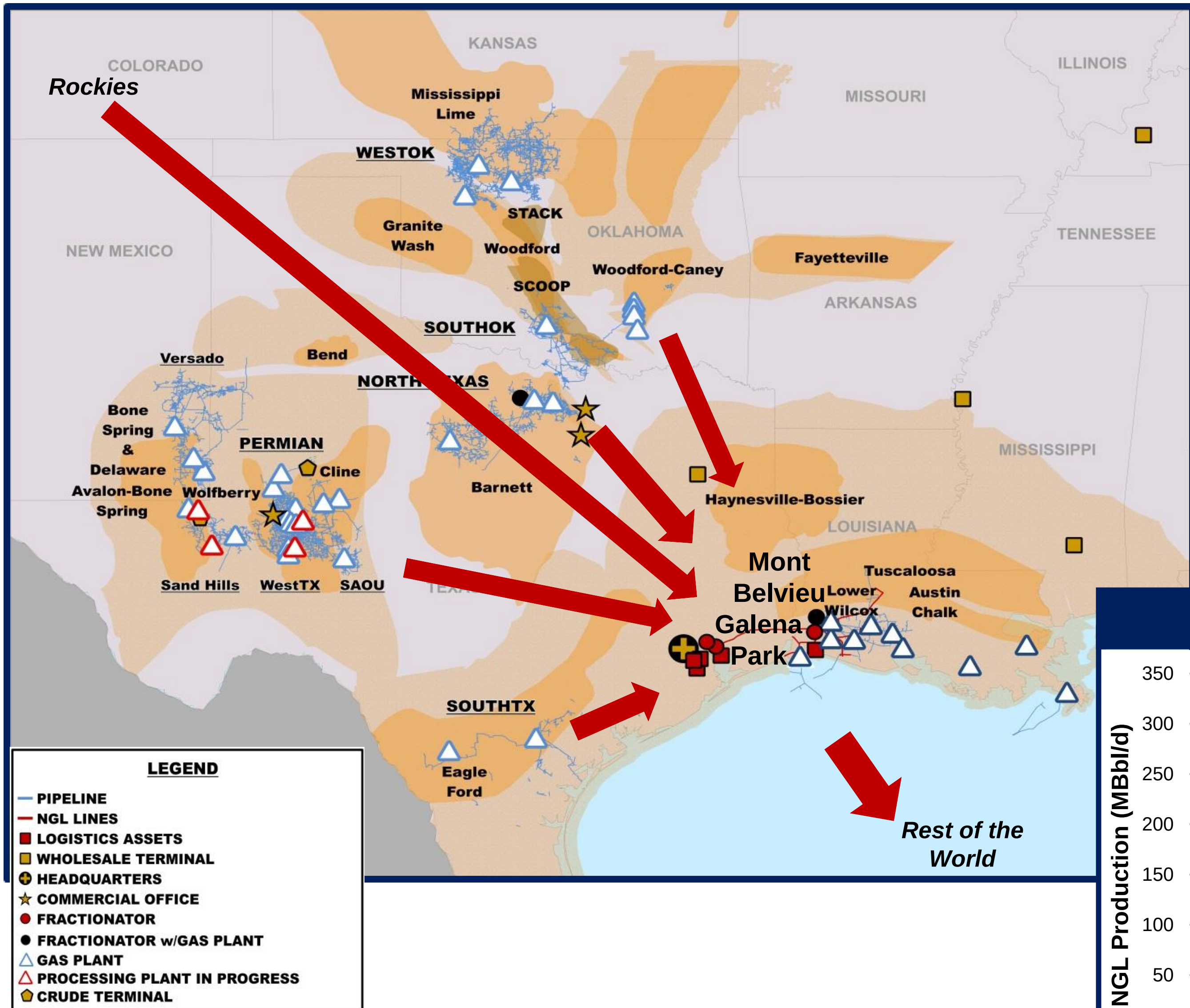
[a] The Chaney Dell Plant was idled in December 2015

Asset Map and Rig Activity[1]

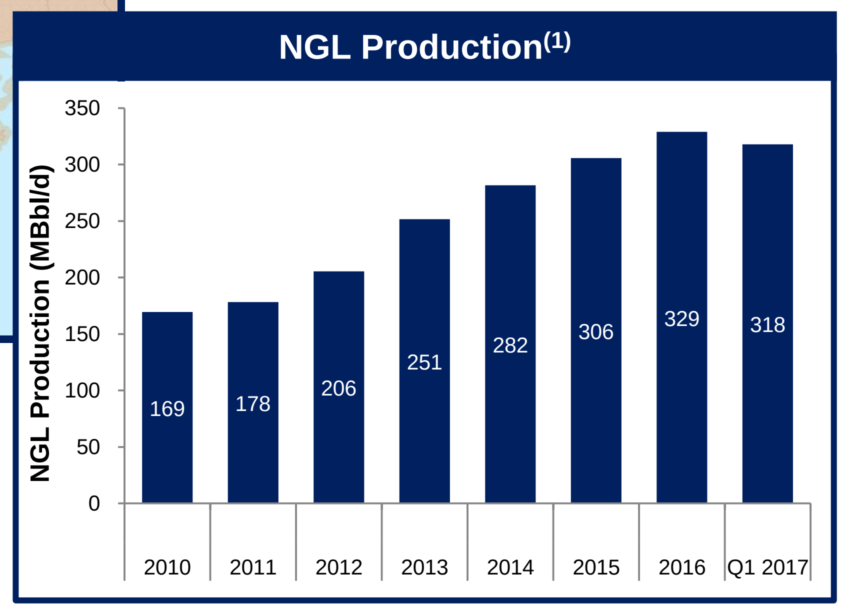


(1) Source: Drillinginfo; rigs as of April 18, 2017

Producer Activity Drives NGL Flows to Mont Belvieu



- Growing field NGL production increases NGL flows to Mont Belvieu
- Increased NGL production will support Targa's expanding Mont Belvieu and Galena Park presence
- Petrochemical investments, fractionation and export services will continue to clear additional domestic supply
- Targa's Mont Belvieu and Galena Park businesses very well positioned



TARGA (1) Pro forma Targa/TPL for all years

Downstream Capabilities

Overview

- **The Logistics and Marketing segment represents approximately 45% of total operating margin(1)**
- **Primarily fixed fee-based businesses, many with "take-or-pay" commitments**
- **Continue to pursue attractive downstream infrastructure growth opportunities**
- **Field G&P growth and increased ethane recovery will bring more volumes downstream**

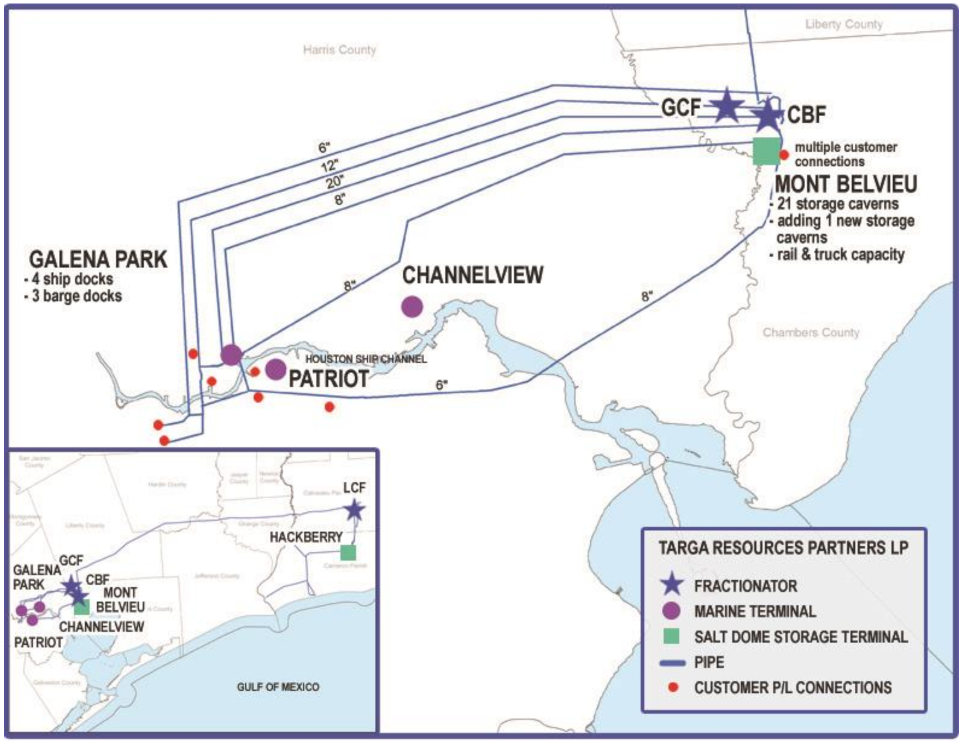
Downstream Businesses

- **NGL Fractionation / Storage**
  - Strong fractionation asset position at Mont Belvieu and Lake Charles (675 MBbl/d of gross processing capacity)
  - Underground storage assets and connectivity provides a locational advantage
  - Fixed fees with "take-or-pay" commitments
- **LPG Exports**
  - Approximately 7 MMBbl/month of LPG Export capacity
  - Fixed loading fees with "take-or-pay" commitments; market to end users and international trading houses
- **Other**
  - NGL and Natural Gas Marketing
    - Manage physical distribution of mixed NGLs and specification products using owned and third party facilities
    - Manage inventories for Targa downstream business
  - Domestic NGL Marketing and Distribution
    - Contractual agreements with major refiners to market NGLs by barge, rail and truck; margin-based fees
    - Sell propane to multi-state, independent retailers and industrial accounts; inventory sold at index plus
  - Logistics and Transportation
    - All fee-based; 650 railcars, 94 transport tractors, 20 NGL barges
  - Petroleum Logistics
    - Gulf Coast, East Coast and West Coast terminals

TARGA

(1) Reflective of trailing twelve months as of March 31, 2017

Logistics Assets – Extensive Gulf Coast Footprint



Galena Park Marine Terminal		
	Products	**MMBbl/ Month**
Export Capacity	LEP / HD5 / NC4	~7.0
Other Assets		
700 MBbls in Above Ground Storage Tanks		
4 Ship Docks		

Fractionators			
		Gross Capacity (MBbl/d)	**Net Capacity (MBbl/d)[(1)]**
CBF - Mont Belvieu	Trains 1-3	253	223
	Backend Capacity	40	35
	Train 4	100	88
	Train 5	100	88
GCF - Mont Belvieu		125	49
Total - Mont Belvieu		618	482
LCF - Lake Charles		55	55
Total		**673**	**537**

Potential Fractionation Expansions

CBF - Mont Belvieu 100MBbl/d Train 6 permitted

CBF - Mont Belvieu 100MBbl/d Train 7 permitable following Train 6 expansion

Other Assets

Mont Belvieu

35 MBbl/d Low Sulfur/Benzene Treating Natural Gasoline Unit

21 Underground Storage Wells

Adding 1 Underground Storage Wells

Pipeline Connectivity to Petchems/Refineries/LCF/etc.

6 Pipelines Connecting Mont Belvieu to Galena Park

Rail and Truck Loading/Unloading Capabilities

Other Gulf Coast Logistics Assets

Channelview Terminal (Harris County, TX)

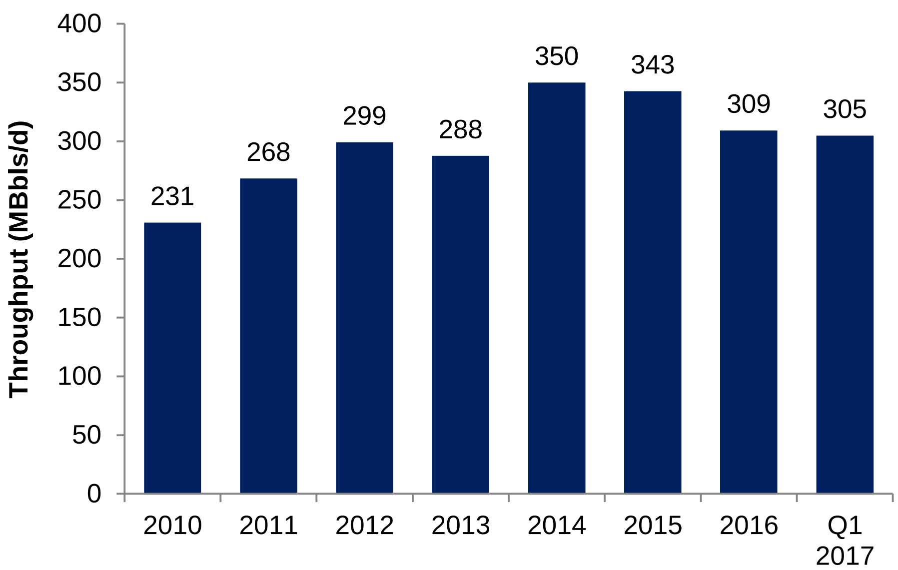
Patriot Terminal (Harris County, TX)

Hackberry Underground Storage (Cameron Parish, LA)

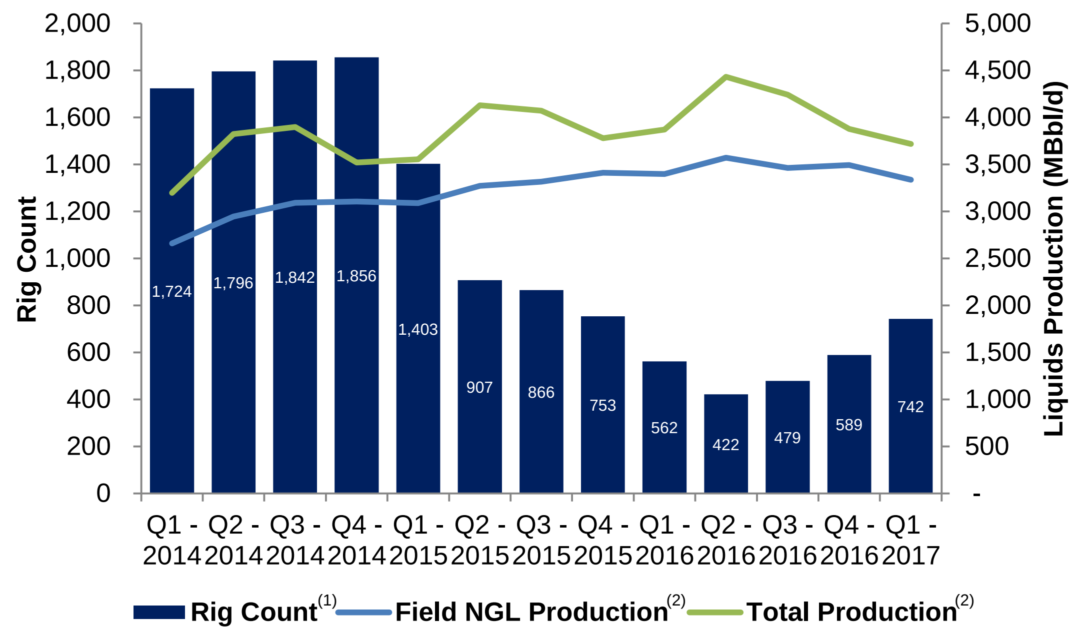
TARGA *(1) Net capacity is calculated based on TRP's 88% ownership of CBF and 39% ownership of GCF*

Targa's Fractionation Assets

Targa Fractionation Footprint



Domestic Rig Count and NGL Supply



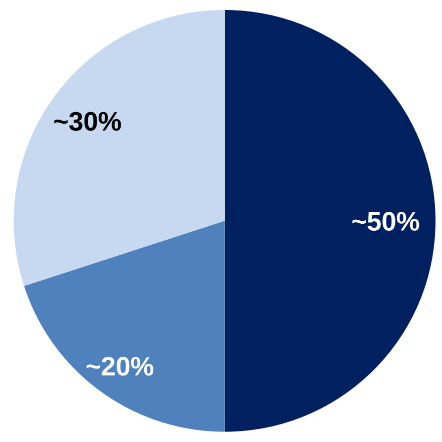
- **453 MBbl/d of frac capacity at CBF, with additional back-end capacity of 40 MBbl/d**
  - 100 Mbbl/d CBF Train 5 operational in May 2016
  - 100 Mbbl/d Train 6 is permitted, with an expectation that moving forward with the project is a matter of "when" and not "if"
- **55 MBbl/d of frac capacity at the interconnected Lake Charles facility**

- **Increasing upstream activity should drive further growth in NGL production directed to Mont Belvieu**
- **Increase in NGL demand fundamentals along the US Gulf Coast is expected to drive need for additional frac capacity**
  - Additional Gulf Coast infrastructure (petchems and an ethane export facility) will drive greater ethane demand and recovery
    - Targa well positioned to benefit

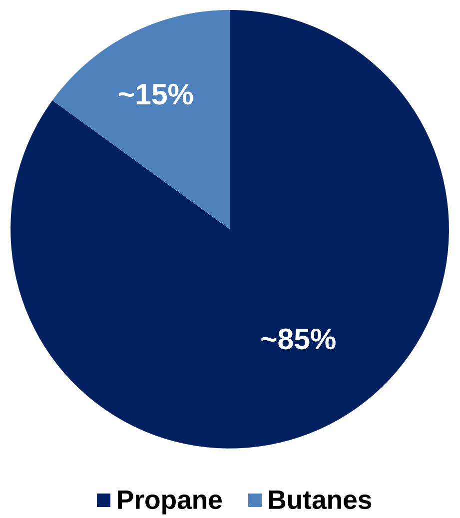
(1) Source: Baker Hughes as of March 31, 2017
(2) Source: EIA as of February 28, 2017

Targa's LPG Export Business

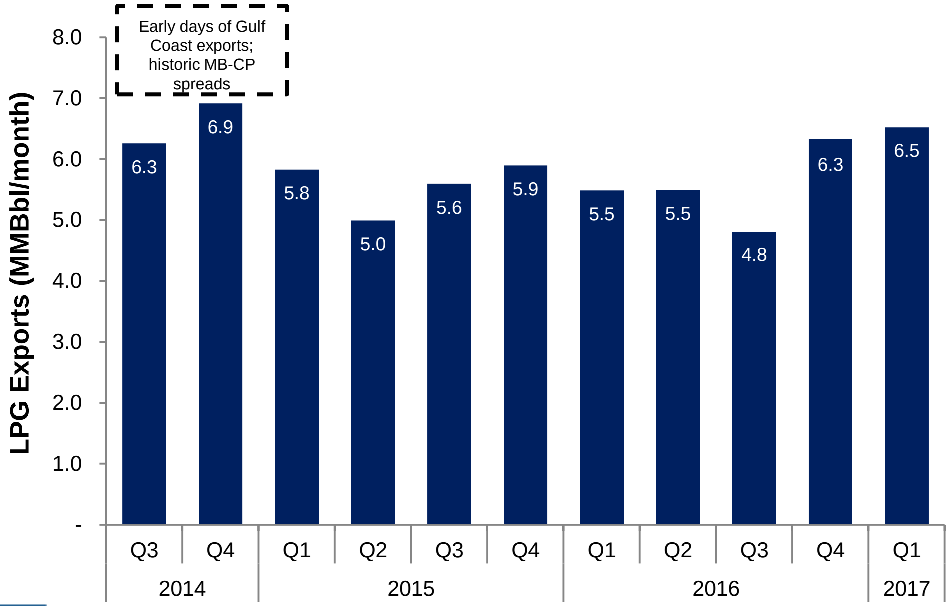
LPG Exports by Destination(1)



Propane and Butane Exports(1)



Galena Park LPG Export Volumes



- **Fee based business (charge fee for vessel loading)**
- **Targa advantaged versus some potential competitors given support infrastructure**
  - Fractionation, storage, supply/market interconnectivity, refrigeration, de-ethanizers, etc.
- **Differentiated facility versus other LPG export facilities due to operational flexibility on vessel size and cargo composition**
- **Nameplate capacity of ~9 MMBbl/month; effective operational capacity of ~7 MMBbl/month or more**
- **~70% of Targa volumes staying in the Americas**
- ***Substantially contracted over the long-term at attractive rates***

(1) *Trailing twelve months – Q2 2016 through Q1 2017*

Additional Information

Q1 2017 Permian Acquisition Earn-Out Structure

Beneficial Transaction Structure

- **Potential earn-out payments are based on realized gross margin[1] on existing contracts as of February 28, 2017 for the Permian Basin assets acquired on March 1, 2017**
- **$565 million of Initial Consideration[2] representing an ~9x 2017E EBITDA multiple**
- **Calculation of Potential Earn-Out Payment #1:**
  - Acquired Delaware = 9.75 *times* Actual Acquired Delaware 2017[1] Gross Margin *less* Initial Delaware Consideration of $385 million
  - Acquired Midland = 9.25 *times* Actual Acquired Midland 2017[1] Gross Margin *less* Initial Midland Consideration of $180 million
- **Calculation of Potential Earn-Out Payment #2:**
  - Acquired Delaware = 8.75 *times* Actual Acquired Delaware 2018[1] Gross Margin *less* (Initial Delaware Consideration of $385 million + Acquired Delaware Earn-Out Payment #1)
  - Acquired Midland = 8.75 *times* Actual Acquired Midland 2018[1] Gross Margin *less* (Initial Acquired Midland Consideration of $180 million + Acquired Midland Earn-Out Payment #1)

Earn-Out Diagram	Acquired Delaware	Acquired Midland	Acquired Consolidated
Initial Consideration[2]	$385 million	$180 million	$565 million
Earn Out #1 Multiple[1]	9.75x	9.25x	N/A
Earn Out #2 Multiple[1]	8.75x	8.75x	N/A
Potential Earn-Out Payments			$935 million
Potential Total Consideration			$1.5 billion

TARGA

(1) Based on Gross Margin generated from existing contracts between March 1, 2017 and February 28, 2018 for Earn Out #1 and (ii) March 1, 2018 and February 28, 2019 for Earn Out #2

(2) $90 million of initial consideration paid within 90 days of closing, balance at closing

Noble Crude and Condensate Splitter Project – Events and Non-GAAP Accounting Treatment

Summary

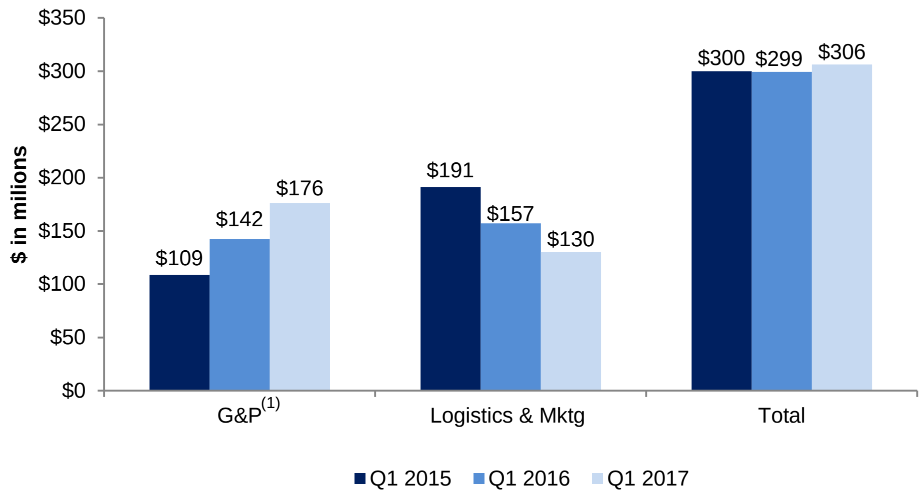
March 31, 2014	◆ **Announced an agreement with Noble Americas Corp., a subsidiary of Noble Group Ltd. ("Noble"), to construct a 35 Mbbl/d condensate splitter located at the Channelview Terminal supported by a long-term, fee-based arrangement**
December 31, 2014	◆ **Noble made a cash payment (recognized in Q1, Q2 and Q3 2015) to Targa to modify the existing agreements to provide time for Noble to analyze the splitter and/or a new terminal at Patriot. The original deal economics from March 2014 were not negatively impacted as a result of the revised agreements**
October 2016	◆ **First ~$40 million pre-payment from Noble received under the terms of the crude and condensate splitter agreements. An ~$40 million pre-payment will be received every October until the year prior to the final year of the contract**

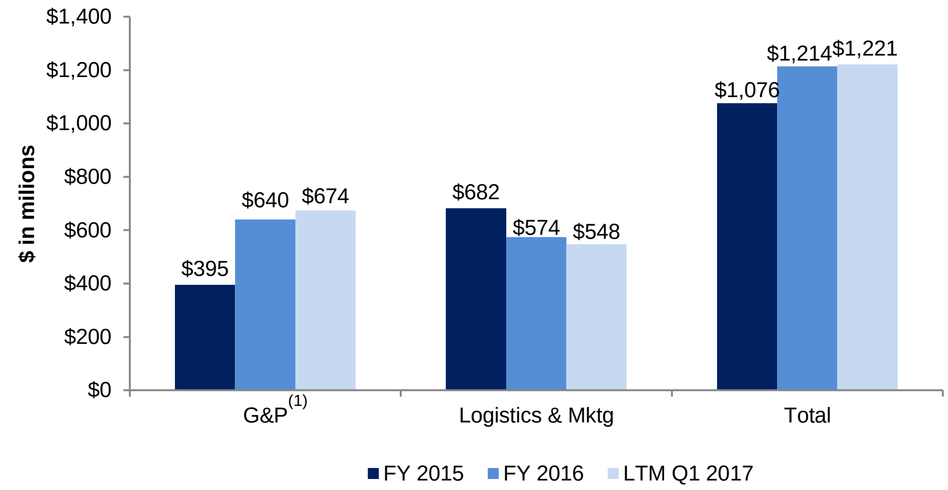
Non-GAAP Accounting Treatment

Date	Description	EBITDA	DCF
Q4 2016	~$40 million cash pre-payment from Noble	+ ~$10 million	+ ~$40 million
Q1 2017		+ ~$10 million	
Q2 2017		+ ~$10 million	
Q3 2017		+ ~$10 million	
Q4 2017	~$40 million cash pre-payment from Noble	+ ~$10 million	+ ~$40 million
Q1 2018	Asset is expected to be operational	+ ~$10 million - associated opex	
Q2 2018		+ ~$10 million - associated opex	
Q3 2018		+ ~$10 million - associated opex	
Q4 2018+	Similar treatment until final contract year (term of contract has not been disclosed)	+ ~$10 million - associated opex	+ ~$40 million - associated opex

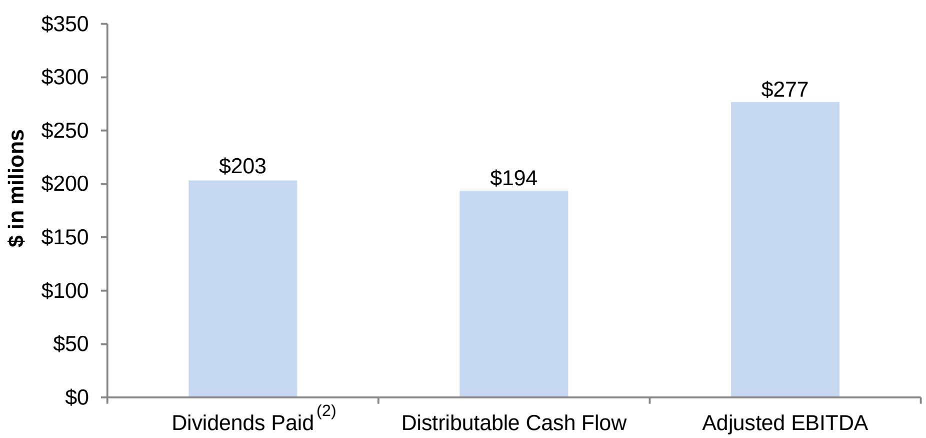
TRC Update

Operating Margin





Q1 2017



Q1 2017 Summary

- **Adjusted EBITDA 5% higher in Q1 2017 versus Q1 2016**
- **TRP compliance Debt / Adjusted EBITDA at 3.6x**
- **$0.91 dividend declared on TRC common shares**
- **$22.9 million of dividends paid on TRC 9.5% Series A preferred shares**

TARGA

(1) Includes impact of commodity hedge settlements
(2) Includes dividends on TRC common shares and on TRC 9.5% Series A preferred shares

Consolidated Capitalization

($ in millions)

Cash and Debt	Maturity	Coupon	12/31/2016	Adjustments	3/1/2017
Cash and Cash Equivalents			$73.5	$6.5	$80.0
TRP Accounts Receivable Securitization	Dec-17		275.0	10.0	285.0
TRP Revolving Credit Facility	Oct-20		150.0	(150.0)	–
TRC Revolving Credit Facility	Feb-20		275.0	160.0	435.0
TRC Term Loan B	Feb-22		160.0	(160.0)	–
Unamortized Discount			(2.2)	2.2	–
Total Senior Secured Debt			**857.8**	**(137.8)**	**720.0**
Senior Notes	Jan-18	5.000%	250.5	-	250.5
Senior Notes	Nov-19	4.125%	749.4	-	749.4
Senior Notes	Aug-22	6.375%	278.7	-	278.7
Senior Notes	May-23	5.250%	559.6	-	559.6
Senior Notes	Nov-23	4.250%	583.9	-	583.9
Senior Notes	Mar-24	6.750%	580.1	-	580.1
Senior Notes	Feb-25	5.125%	500.0	-	500.0
Senior Notes	Feb-27	5.375%	500.0	-	500.0
TPL Senior Notes	Nov-21	4.750%	6.5	-	6.5
TPL Senior Notes	Aug-23	5.875%	48.1	-	48.1
Unamortized Premium on TPL Debt			0.5	-	0.5
Total Consolidated Debt			**$4,915.1**	**($137.8)**	**$4,777.3**
TRP Compliance Leverage Ratio(1)			3.8x		3.6x
TRC Compliance Leverage Ratio(2)			0.7x		0.6x
Liquidity:					
TRP Credit Facility Commitment			$1,600.0	–	1,600.0
Funded Borrowings			(150.0)	150.0	–
Letters of Credit			(13.2)	(2.6)	(15.8)
Total TRP Revolver Availability			**$1,436.8**		**$1,584.2**
Available A/R Securitization Capacity			-		65.0
Total TRP Liquidity with Available A/R Securitization Capacity			**$1,436.8**		**$1,649.2**
Available TRC Credit Facility Availability			395.0		235.0
Cash			73.5		80.0
Total Consolidated Liquidity			**$1,905.3**		**$1,964.2**

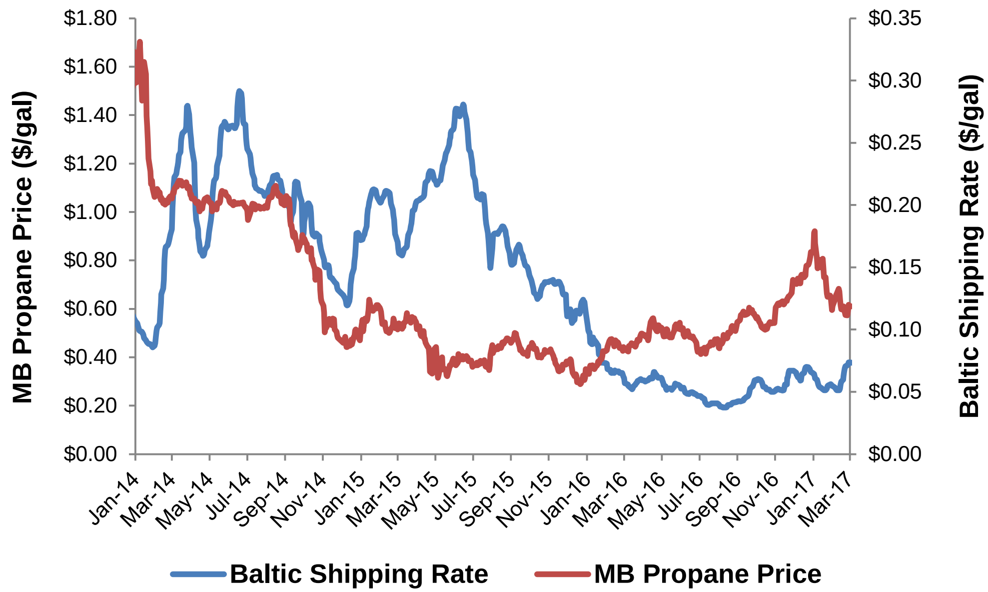
TARGA

(1) Adjusts EBITDA to provide credit for material capital projects that are in process, but have not started commercial operation, and other items; compliance debt excludes senior notes of Targa Pipeline Partners, L.P. ("TPL") and $250 million of borrowings under the A/R Securitization Facility

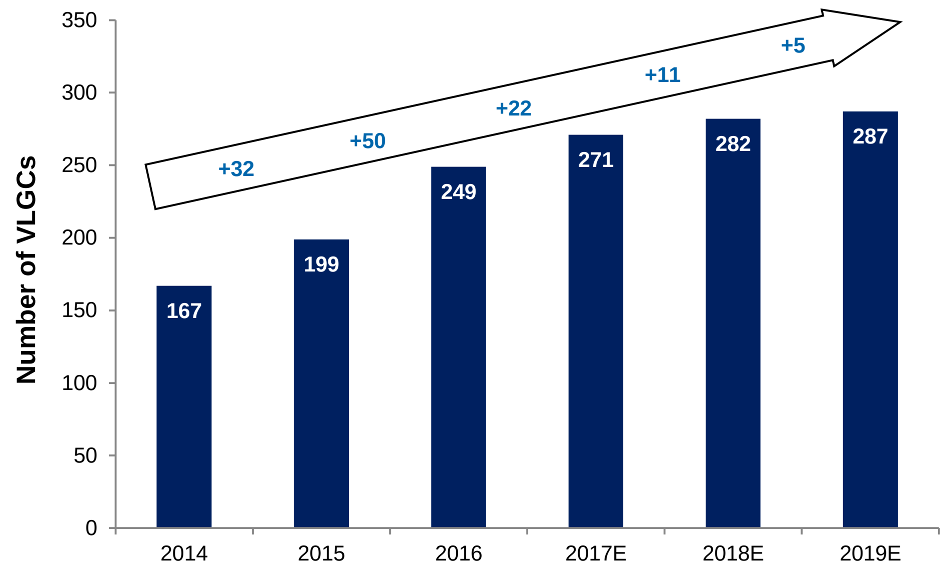
(2) TRC compliance leverage deducts non-TRP cash and cash equivalents from debt

Dynamics of the LPG Market

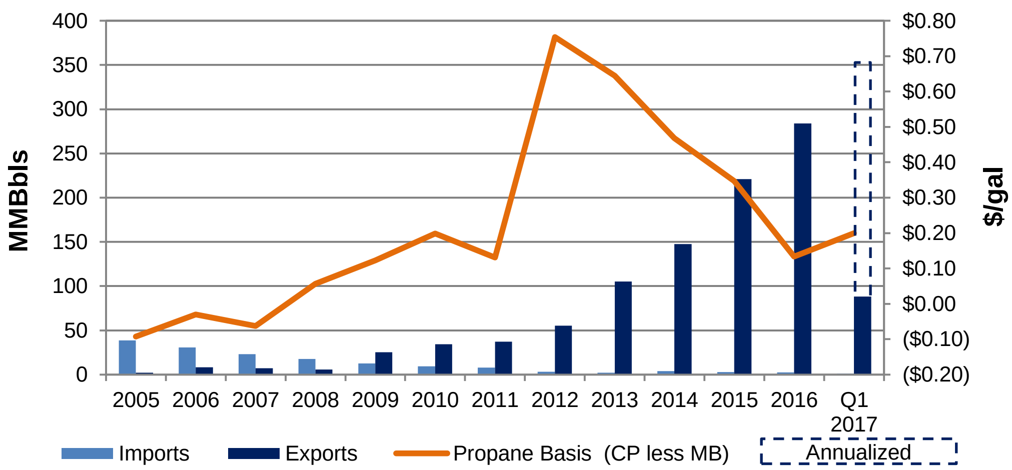
VLGC Freight Rates[1]



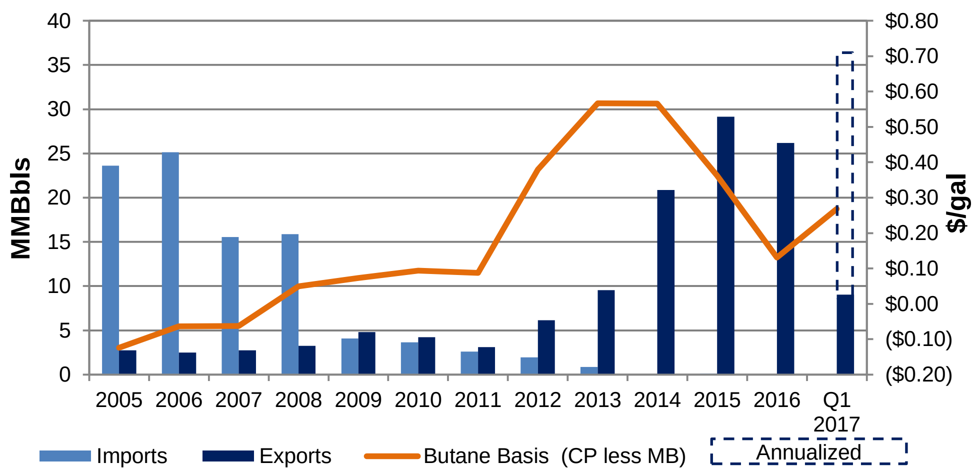
Increasing VLGC Fleet[2]



U.S. Propane[3]



U.S. Butane[3]



TARGA

(1) Source: Baltic Exchange; Bloomberg
(2) Source: Waterborne
(3) Source: IHS

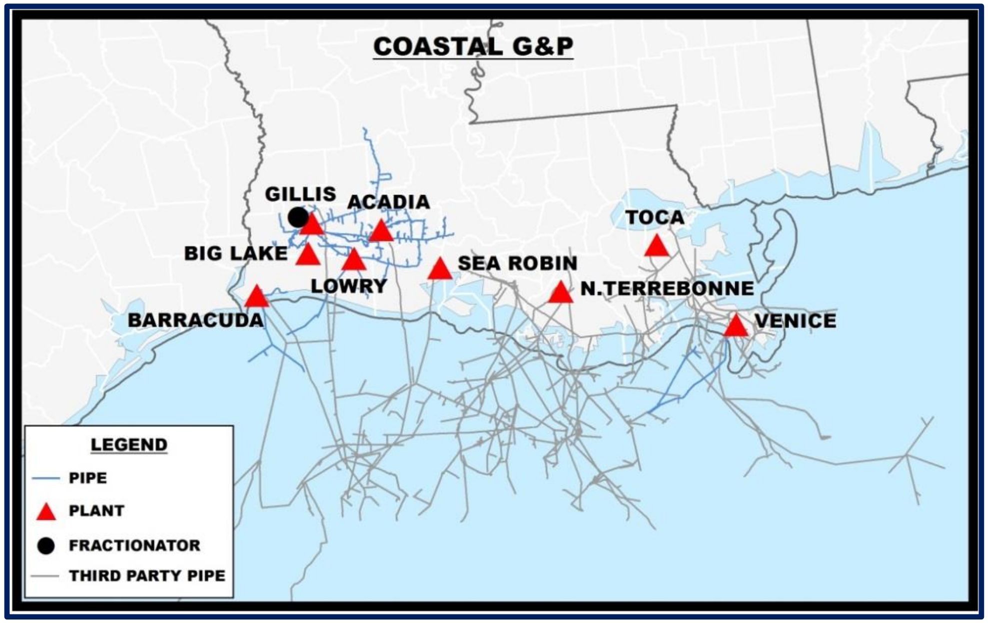
Coastal – Gulf Coast Footprint

Summary

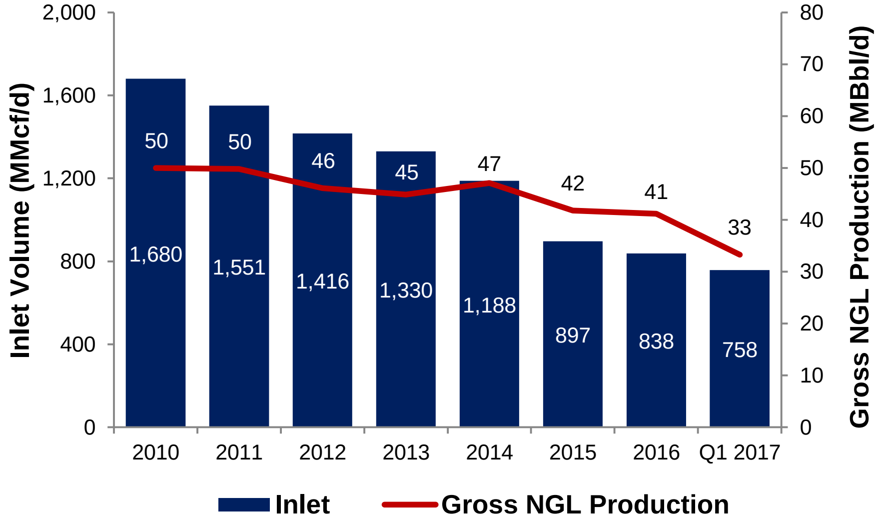
- **Asset position represents a competitively advantaged straddle option on Gulf of Mexico activity over time**
- **LOU (Louisiana Operating Unit)**
  - 440 MMcf/d of gas processing (180 MMcf/d Gillis plant, 80 MMcf/d Acadia plant and 180 MMcf/d Big Lake plant)
  - Interconnected to Lake Charles Fractionator (LCF)
- **Coastal Straddles (including VESCO)**
  - Positioned on mainline gas pipelines processing volumes of gas collected from offshore
- **Coastal inlet volumes and NGL production have been declining, but NGL production decreases have been partially offset by processing volumes at more efficient plants**
- **Hybrid contracts (POL with fee floors)**

	Current Gross Processing Capacity (MMcf/d)	Q1 2017 NGL Production (MBbl/d)
LOU	440	
Vesco	750	
Other Coastal Straddles	3,255	
Total	**4,445**	**33**

Footprint



Volumes



TARGA

Reconciliations

Non-GAAP Measures Reconciliation

This presentation includes the non-GAAP financial measures of Adjusted EBITDA and Distributable Cash Flow. The presentation provides a reconciliation of this non-GAAP financial measures to its most directly comparable financial measure calculated and presented in accordance with generally accepted accounting principles in the United States of America ("GAAP"). Our non-GAAP financial measures should not be considered as alternatives to GAAP measures such as net income, operating income, net cash flows provided by operating activities or any other GAAP measure of liquidity or financial performance.

Non-GAAP Measures Reconciliation

Adjusted EBITDA - The Company defines Adjusted EBITDA as net income (loss) available to TRC before: interest; income taxes; depreciation and amortization; impairment of goodwill; gains or losses on debt repurchases, redemptions, amendments, exchanges and early debt extinguishments and asset disposals; risk management activities related to derivative instruments including the cash impact of hedges acquired in the merger with APL (the "APL merger"); non-cash compensation on equity grants; transaction costs related to business acquisitions; the Splitter Agreement adjustment; net income attributable to TRP preferred limited partners; earnings/losses from unconsolidated affiliates net of distributions, distributions from preferred interests, change in contingent consideration and the noncontrolling interest portion of depreciation and amortization expense. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others. The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and pay dividends to our investors.

Adjusted EBITDA is a non-GAAP financial measure. The GAAP measure most directly comparable to Adjusted EBITDA is net income (loss) attributable to TRC. Adjusted EBITDA should not be considered as an alternative to GAAP net income. Adjusted EBITDA has important limitations as an analytical tool. Investors should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Management compensates for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into its decision-making processes.

Non-GAAP Measures Reconciliation

Distributable Cash Flow - The Company defines distributable cash flow as Adjusted EBITDA less distributions to TRP preferred limited partners, the Splitter Agreement adjustments, cash interest expense on debt obligations, cash tax (expense) benefit and maintenance capital expenditures (net of any reimbursements of project costs). This measure includes the impact of noncontrolling interests on the prior adjustment items.

Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by our board of directors) to the cash dividends we expect to pay our shareholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to cash dividends. Distributable cash flow is also an important financial measure for our shareholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly dividend rates.

Distributable cash flow is a non-GAAP financial measure. The GAAP measure most directly comparable to distributable cash flow is net income (loss) attributable to TRC. Distributable cash flow should not be considered as an alternative to GAAP net income (loss) available to common and preferred shareholders. It has important limitations as an analytical tool. Investors should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Management compensates for the limitations of distributable cash flow as an analytical tool by reviewing the comparable GAAP measure, understanding the differences between the measures and incorporating these insights into our decision-making processes.

Non-GAAP Reconciliations – Q1 2017 EBITDA and DCF

The following table presents a reconciliation of Adjusted EBITDA and Distributable Cash Flow for the periods shown for TRC:

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
	($ in millions)	
Reconciliation of net income (loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow:		
Net income (loss) to Targa Resources Corp.	$ (119.3)	$ (2.7)
Add:		
Impact of TRC/TRP Merger on NCI	-	(3.8)
Income attributable to TRP preferred limited partners	2.8	2.8
Interest expense, net	63.0	52.9
Income tax expense (benefit)	71.1	3.1
Depreciation and amortization expense	191.1	193.5
Goodwill impairment	-	24.0
(Gain) loss on sale or disposition of assets	16.1	0.9
(Gain) loss from financing activities	5.8	(24.7)
(Earnings) loss from unconsolidated affiliates	12.6	4.8
Distributions from unconsolidated affiliates and preferred partner interests, net	4.2	5.8
Change in contingent consideration	3.3	-
Compensation on TRP equity grants	10.8	8.0
Transaction costs related to business acquisitions	5.1	-
Splitter Agreement	10.8	-
Risk management activities	3.6	5.9
Noncontrolling interest adjustment	(4.3)	(5.8)
TRC Adjusted EBITDA	$ 276.7	$ 264.7
Distributions to TRP preferred limited partners	(2.8)	(2.8)
Splitter Agreement	(10.8)	-
Interest expenses on debt obligations, net	(59.0)	(69.7)
Cash tax (expense) benefit	15.3	-
Maintenance capital expenditures	(25.7)	(15.0)
Noncontrolling interests adjustments of maintenance capex	0.3	0.8
TRC Distributable Cash Flow	$ 194.0	$ 178.0

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Non-GAAP Reconciliations – Q1 2017 Gross Margin

The following table presents a reconciliation of net income (loss) to operating margin and gross margin for the periods shown for TRC:

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
	($ in millions)	
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin:		
Net income (loss) attributable to Targa Resources Corp.	$ (119.3)	$ (2.7)
Net income (loss) attributable to noncontrolling interests	8.8	2.0
Net income	(110.5)	(0.7)
Depreciation and amortization expenses	191.1	193.5
General and administrative expenses	48.7	45.3
Goodwill impairment	-	24.0
Interest expense, net	63.0	52.9
Income tax expense (benefit)	71.1	3.1
Gain (loss) on sale or disposition of assets	16.1	0.9
Gain (loss) from financing activities	5.8	(24.7)
Other, net	21.2	5.0
Operating margin	306.5	299.3
Operating expenses	151.9	132.1
Gross margin	$ 458.4	$ 431.4

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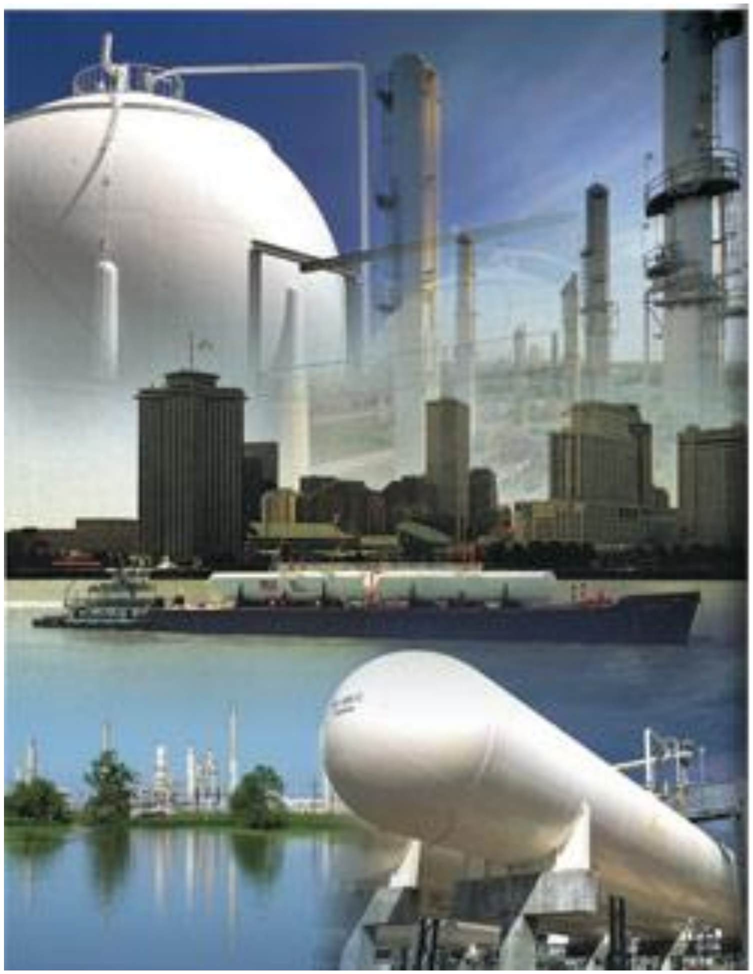

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