UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): April 30, 2015

NATIONAL FUEL GAS COMPANY
(Exact name of registrant as specified in its charter)

New Jersey	1-3880	13-1086010
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

6363 Main Street, Williamsville, New York	14221
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (716) 857-7000

Former name or former address, if changed since last report: Not Applicable

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (*see* General Instruction A.2. below):

- ☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
- ☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
- ☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
- ☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 7.01 Regulation FD Disclosure.

On April 30, 2015, National Fuel Gas Company (the "Company") updated its Investor Presentation. A copy of the presentation is furnished as part of this Current Report as Exhibit 99.

Neither the furnishing of the presentation as an exhibit to this Current Report nor the inclusion in such presentation of any reference to the Company's internet address shall, under any circumstances, be deemed to incorporate the information available at such internet address into this Current Report. The information available at the Company's internet address is not part of this Current Report or any other report filed or furnished by the Company with the Securities and Exchange Commission.

In addition to financial measures calculated in accordance with generally accepted accounting principles ("GAAP"), the presentation furnished as part of this Current Report as Exhibit 99 contains certain non-GAAP financial measures. The Company believes that such non-GAAP financial measures are useful to investors because they provide an alternative method for assessing the Company's operating results in a manner that is focused on the performance of the Company's ongoing operations, for measuring the Company's cash flow and liquidity, and for comparing the Company's financial performance to other companies. The Company's management uses these non-GAAP financial measures for the same purpose, and for planning and forecasting purposes. The presentation of non-GAAP financial measures is not meant to be a substitute for financial measures prepared in accordance with GAAP.

Certain statements contained herein or in the materials furnished as part of this Current Report, including statements regarding estimated future earnings and statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will" and "may" and similar expressions, are "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995. There can be no assurance that the Company's projections will in fact be achieved nor do these projections reflect any acquisitions or divestitures that may occur in the future. While the Company's expectations, beliefs and projections are expressed in good faith and are believed to have a reasonable basis, actual results may differ materially from those projected in forward-looking statements. Furthermore, each forward-looking statement speaks only as of the date on which it is made. In addition to other factors, the following are important factors that could cause actual results to differ materially from those discussed in the forward-looking statements: factors affecting the Company's ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations; impairments under the SEC's full cost ceiling test for natural gas and oil reserves; changes in the price of natural gas or oil; changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing; governmental/regulatory actions, initiatives and proceedings, including those involving rate

cases (which address, among other things, target rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal; changes in price differentials between similar quantities of natural gas or oil sold at different geographic locations, and the effect of such changes on commodity production, revenues and demand for pipeline transportation capacity to or from such locations; other changes in price differentials between similar quantities of natural gas or oil having different quality, heating value, hydrocarbon mix or delivery date; the cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company; uncertainty of oil and gas reserve estimates; significant differences between the Company's projected and actual production levels for natural gas or oil; delays or changes in costs or plans with respect to Company projects or related projects of other companies, including difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators; changes in demographic patterns and weather conditions; changes in the availability, price or accounting treatment of derivative financial instruments; financial and economic conditions, including the availability of credit, and occurrences affecting the Company's ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company's credit ratings and changes in interest rates and other capital market conditions; changes in economic conditions, including global, national or regional recessions, and their effect on the demand for, and customers' ability to pay for, the Company's products and services; the creditworthiness or performance of the Company's key suppliers, customers and counterparties; economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation; significant differences between the Company's projected and actual capital expenditures and operating expenses; changes in laws, actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company's pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities; increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; or increasing costs of insurance, changes in coverage and the ability to obtain insurance. The Company disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

Exhibit 99 Investor Presentation dated April 2015

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

NATIONAL FUEL GAS COMPANY

By: /s/ James R. Peterson
James R. Peterson
Assistant Secretary

Dated: April 30, 2015

EXHIBIT INDEX

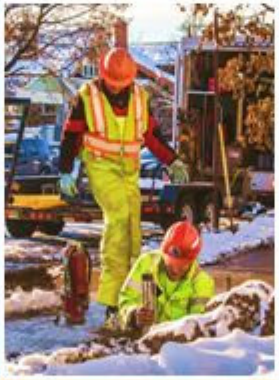
Exhibit Number	Description
99	Investor Presentation dated April 2015

Exhibit 99

National Fuel

National Fuel Gas Company
Investor Presentation

April 2015



Safe Harbor For Forward Looking Statements

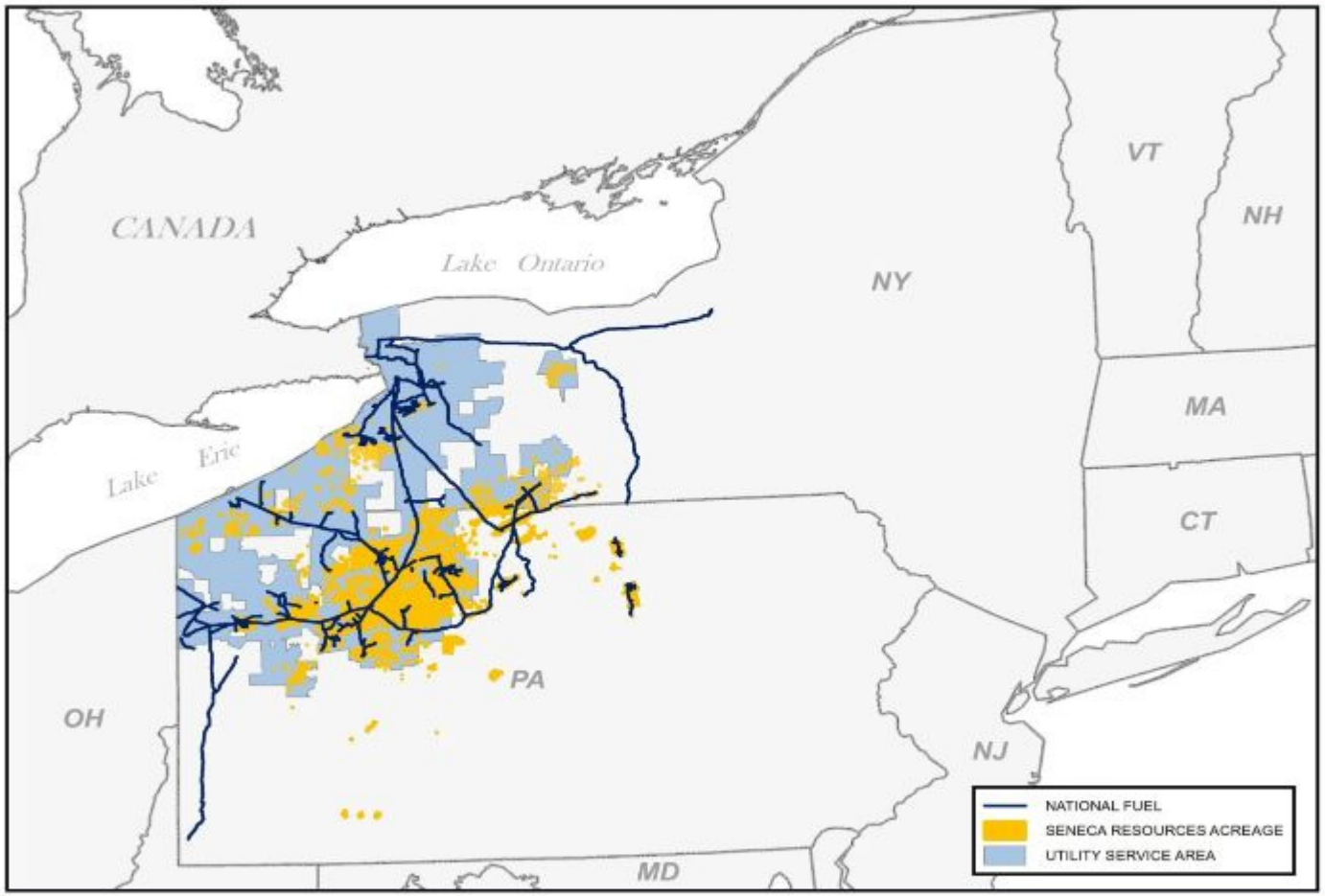
This presentation may contain "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995, including statements regarding future prospects, plans, objectives, goals, projections, estimates of oil and gas quantities, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will," "may," and similar expressions. Forward-looking statements involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, but there can be no assurance that management's expectations, beliefs or projections will result or be achieved or accomplished.

In addition to other factors, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements: factors affecting the Company's ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations; impairments under the SEC's full cost ceiling test for natural gas and oil reserves; changes in the price of natural gas or oil; changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing; governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, target rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal; changes in price differentials between similar quantities of natural gas or oil sold at different geographic locations, and the effect of such changes on commodity production, revenues and demand for pipeline transportation capacity to or from such locations; other changes in price differentials between similar quantities of natural gas or oil having different quality, heating value, hydrocarbon mix or delivery date; the cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company; uncertainty of oil and gas reserve estimates; significant differences between the Company's projected and actual production levels for natural gas or oil; delays or changes in costs or plans with respect to Company projects or related projects of other companies, including difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators; changes in demographic patterns and weather conditions; changes in the availability, price or accounting treatment of derivative financial instruments; financial and economic conditions, including the availability of credit, and occurrences affecting the Company's ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company's credit ratings and changes in interest rates and other capital market conditions; changes in economic conditions, including global, national or regional recessions, and their effect on the demand for, and customers' ability to pay for, the Company's products and services; the creditworthiness or performance of the Company's key suppliers, customers and counterparties; economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation; significant differences between the Company's projected and actual capital expenditures and operating expenses; changes in laws, actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company's pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities; increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; or increasing costs of insurance, changes in coverage and the ability to obtain insurance.

Forward-looking statements include estimates of oil and gas quantities. Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible under existing economic conditions, operating methods and government regulations. Other estimates of oil and gas quantities, including estimates of probable reserves, possible reserves, and resource potential, are by their nature more speculative than estimates of proved reserves. Accordingly, estimates other than proved reserves are subject to substantially greater risk of being actually realized. Investors are urged to consider closely the disclosure in our Form 10-K available at www.nationalfuelgas.com. You can also obtain this form on the SEC's website at www.sec.gov.

For a discussion of the risks set forth above and other factors that could cause actual results to differ materially from results referred to in the forward-looking statements, see "Risk Factors" in the Company's Form 10-K for the fiscal year ended September 30, 2014 and the Forms 10-Q for the quarters ended December 31, 2014 and March 31, 2015. The Company disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date thereof or to reflect the occurrence of unanticipated events.

Quality Assets, Exceptional Location, Unique Integration



- ✓ 800,000+ Net Acres in Pennsylvania
- ✓ 1.9 Tcfe of Proved Reserves (1)
- ✓ 3 Million BBls of Annual Crude Oil Production
- ✓ $265 Million of Midstream Adjusted EBITDA (2)

(1) Total proved reserves are as of September 30, 2014.

(2) For the trailing twelve months ended March 31, 2015. A reconciliation of Adjusted EBITDA to Net Income as presented on the Consolidated Statement of Income and Earnings Reinvested in the Business is included at the end of this presentation.

The National Fuel Value Proposition

Considerable Upstream and Midstream Growth Opportunities in Appalachia

- ✓ 800,000+ net acres in Pennsylvania – 2nd largest acreage position in Marcellus Shale(1)
- ✓ WDA mineral ownership = no royalty or drilling commitments
- ✓ Stacked pay potential in Marcellus, Utica and Geneseo shales
- ✓ Coordinated midstream infrastructure build-out
- ✓ Opportunity for further pipeline expansion to accommodate Appalachian supply growth

Unique Integrated Business Model Provides Competitive Advantage

- ✓ Integration significantly reduces operational and financing costs
- ✓ Diversified cash flows provide stability in challenging commodity price environment

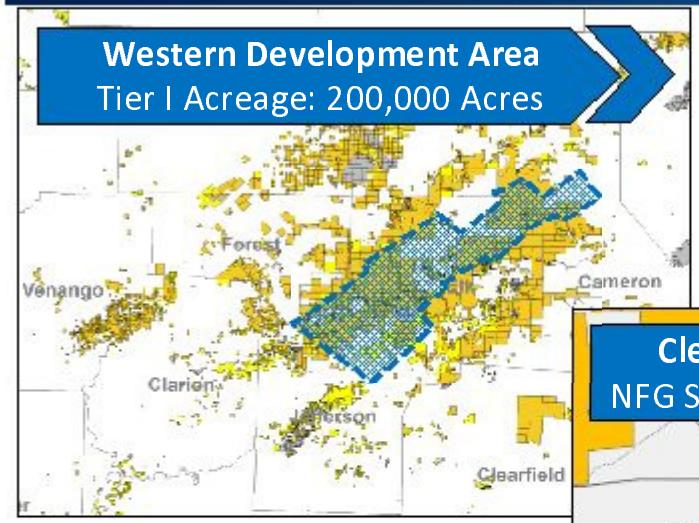
Strong Balance Sheet and History of Disciplined Financial Management

- ✓ Investment grade credit rating and liquidity to support Appalachian growth strategy
- ✓ Disciplined capital investment focused on economic returns
- ✓ 112-year commitment to the dividend

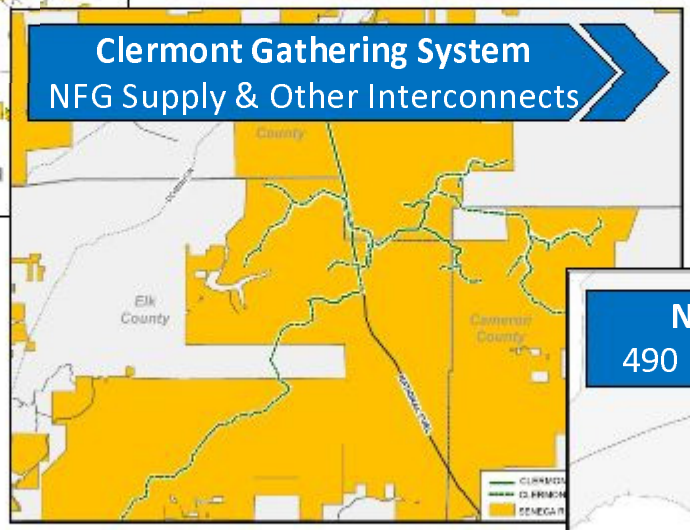
Creating sustainable value for shareholders remains our #1 priority

(1) Per NGI's *Shale Daily* (January 5, 2015). The Company has identified 780,000 acres as prospective in Marcellus Shale.

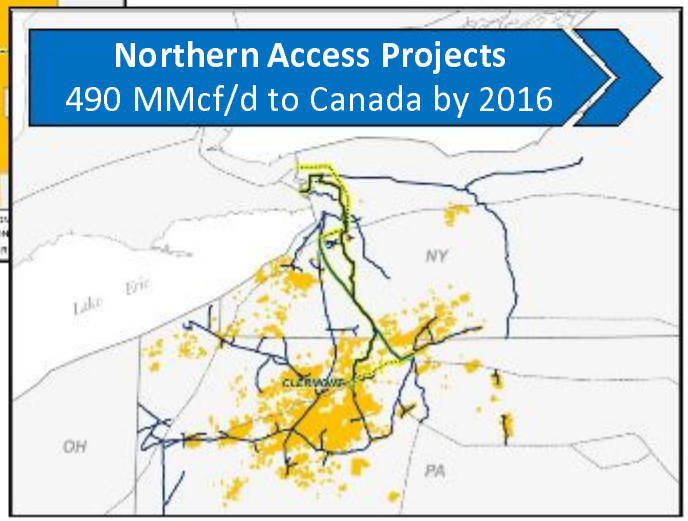
Upstream & Midstream – Common Vision For Growth



High quality Marcellus acreage

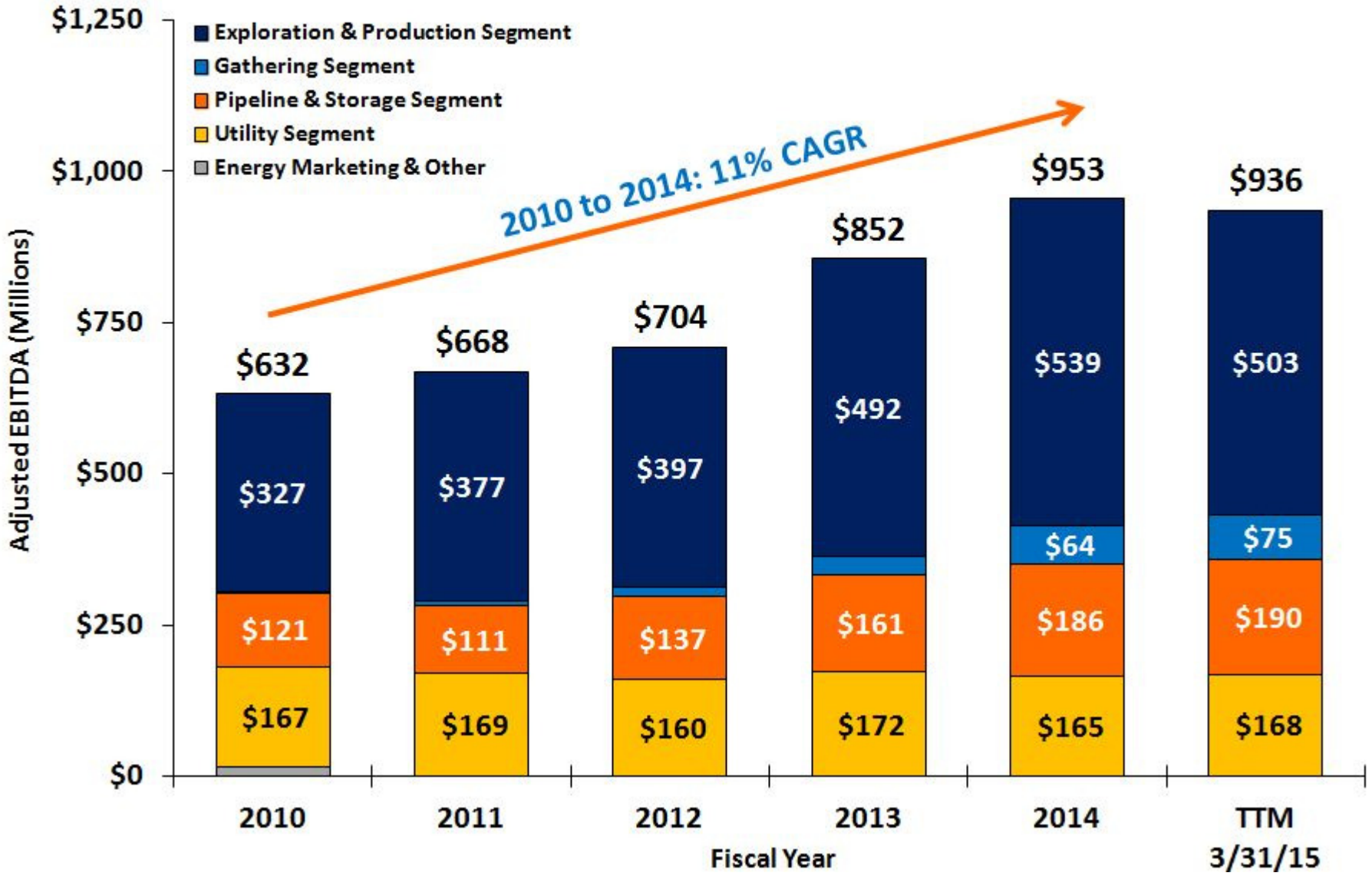


Connected to our interstate pipeline network



Pipeline capacity to premium and alternate markets

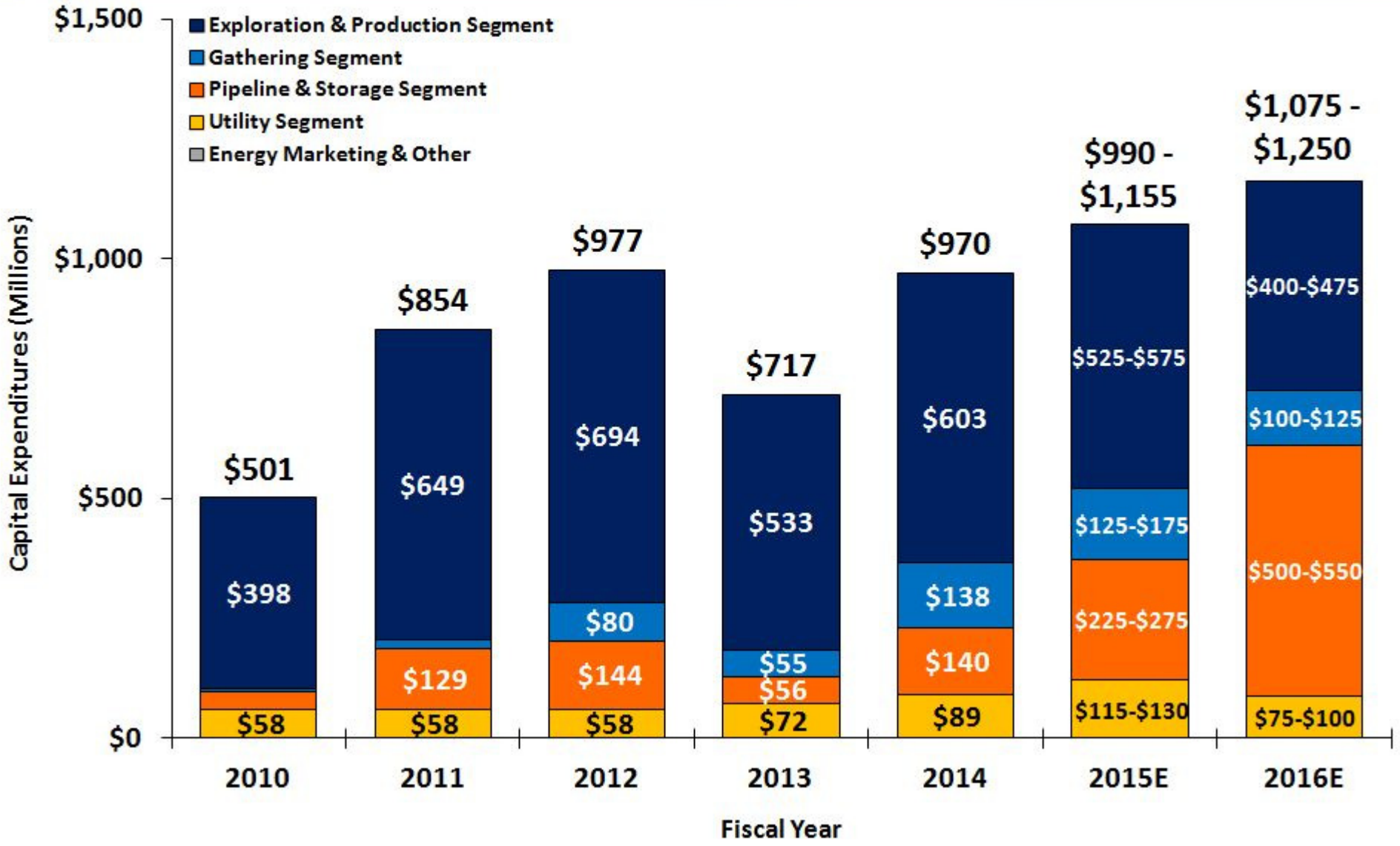
EBITDA Contribution by Segment



Note: A reconciliation of Adjusted EBITDA to Net Income as presented on the Consolidated Statement of Income and Earnings Reinvested in the Business is included at the end of this presentation.

Adjusting Capex to Capitalize on Opportunities

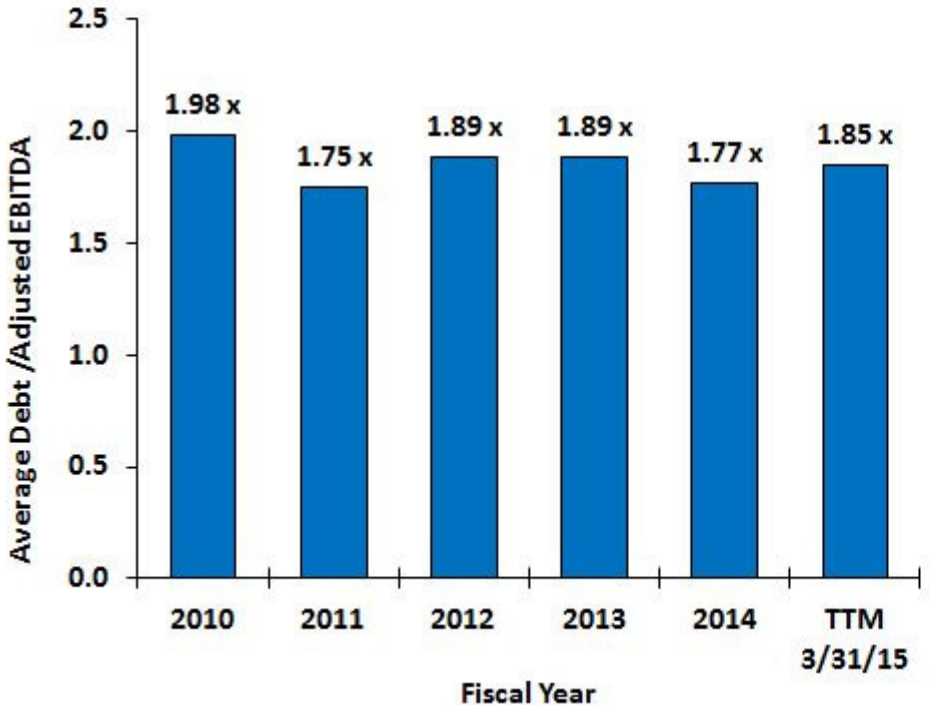
Corporate



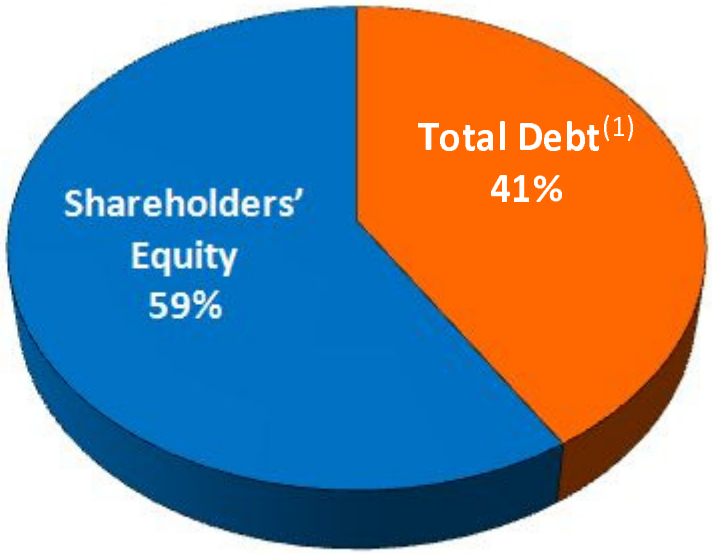
Note: A reconciliation to Capital Expenditures as presented on the Consolidated Statement of Cash Flows is included at the end of this presentation.

Maintaining a Strong Balance Sheet

Debt/Adjusted EBITDA



Capitalization



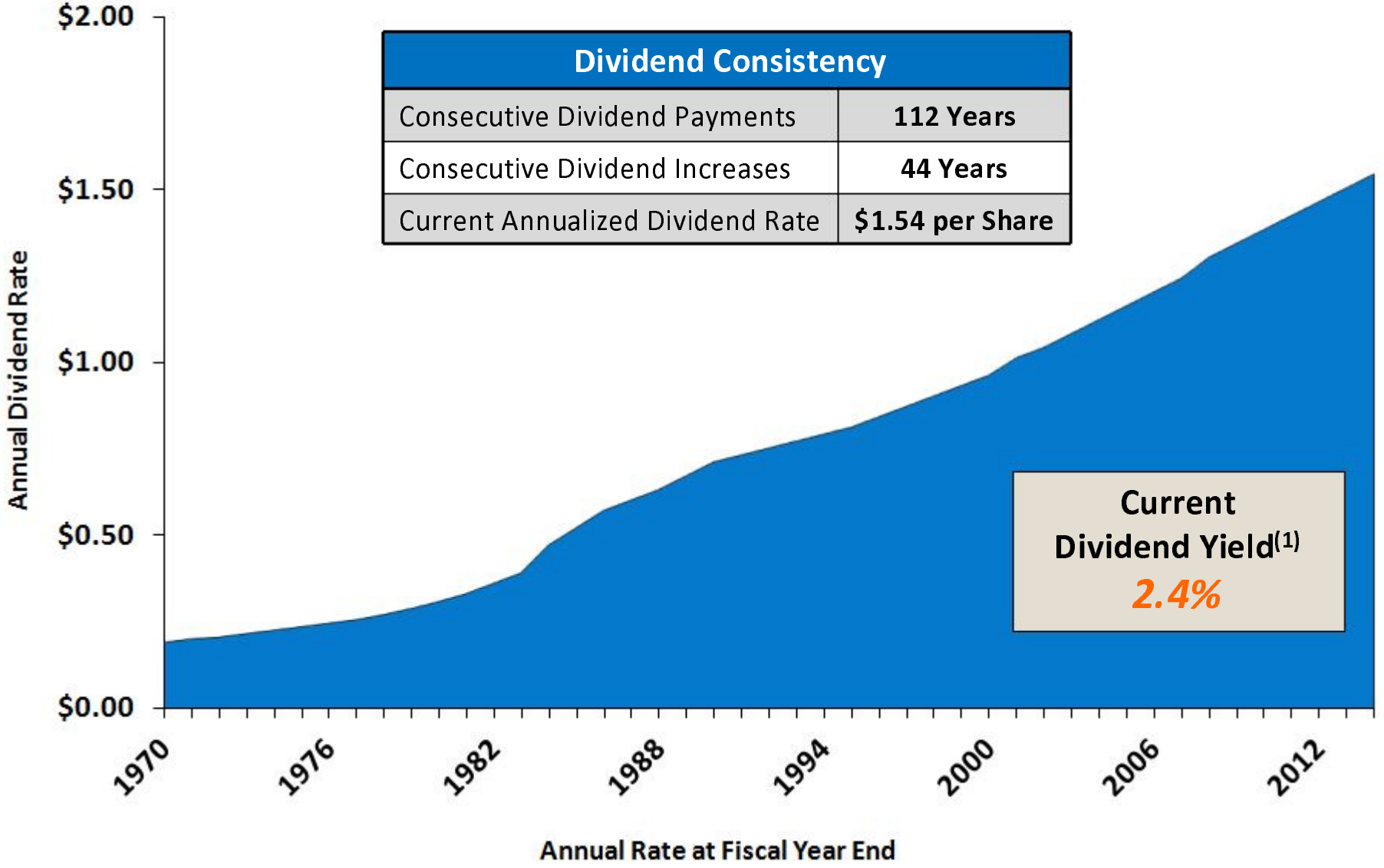
$4.4 Billion
As of March 31, 2015

Note: A reconciliation of Adjusted EBITDA to Net Income is included at the end of this presentation.

(1) Long-term debt of $1.649 billion and short-term debt of $157.5 million.

Dividend Track Record

Dividend Consistency	
Consecutive Dividend Payments	**112 Years**
Consecutive Dividend Increases	**44 Years**
Current Annualized Dividend Rate	**$1.54 per Share**

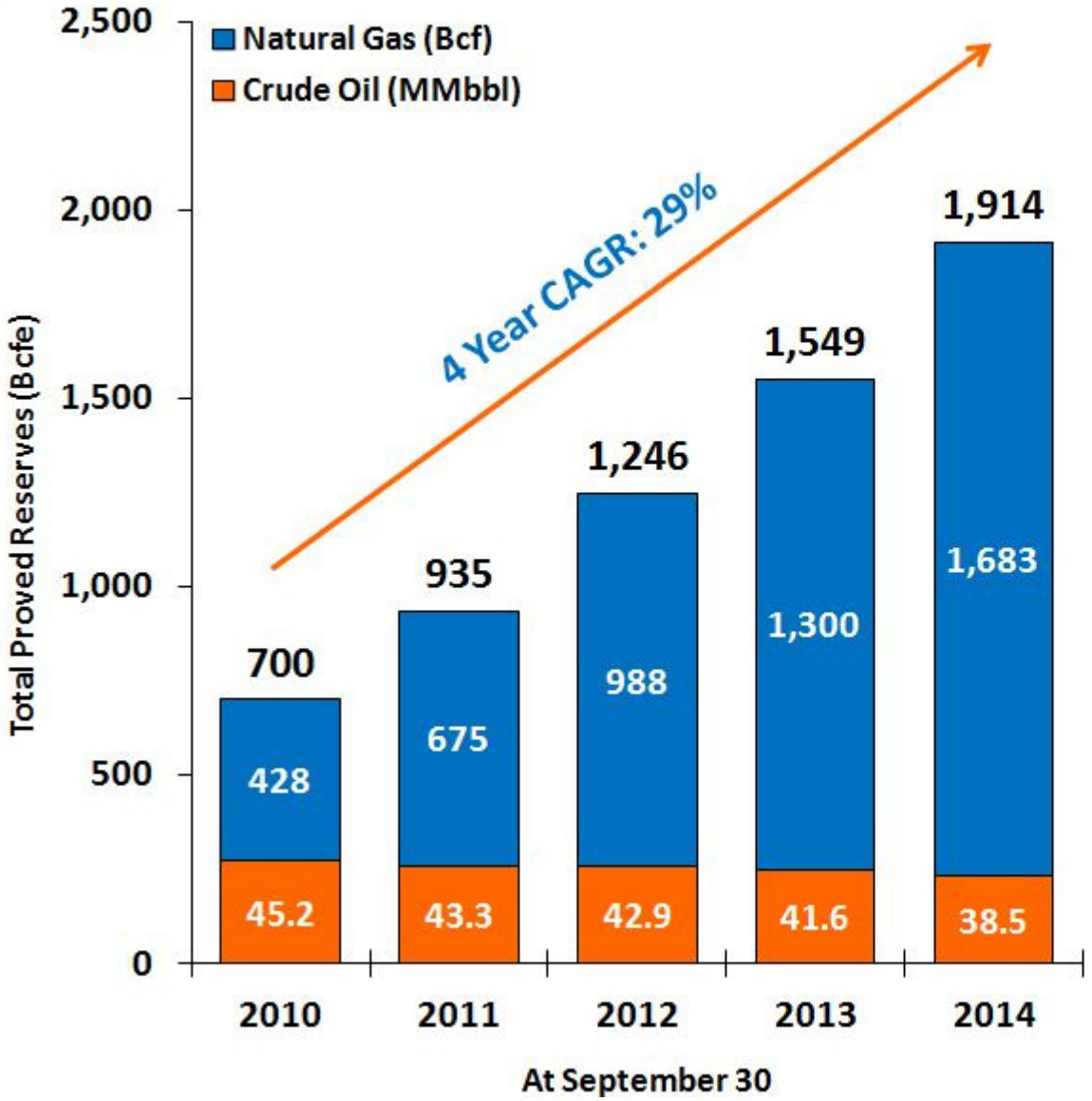


(1) As of April 29, 2015.

Upstream Overview

Exploration & Production

Proven Record of Reserve Growth

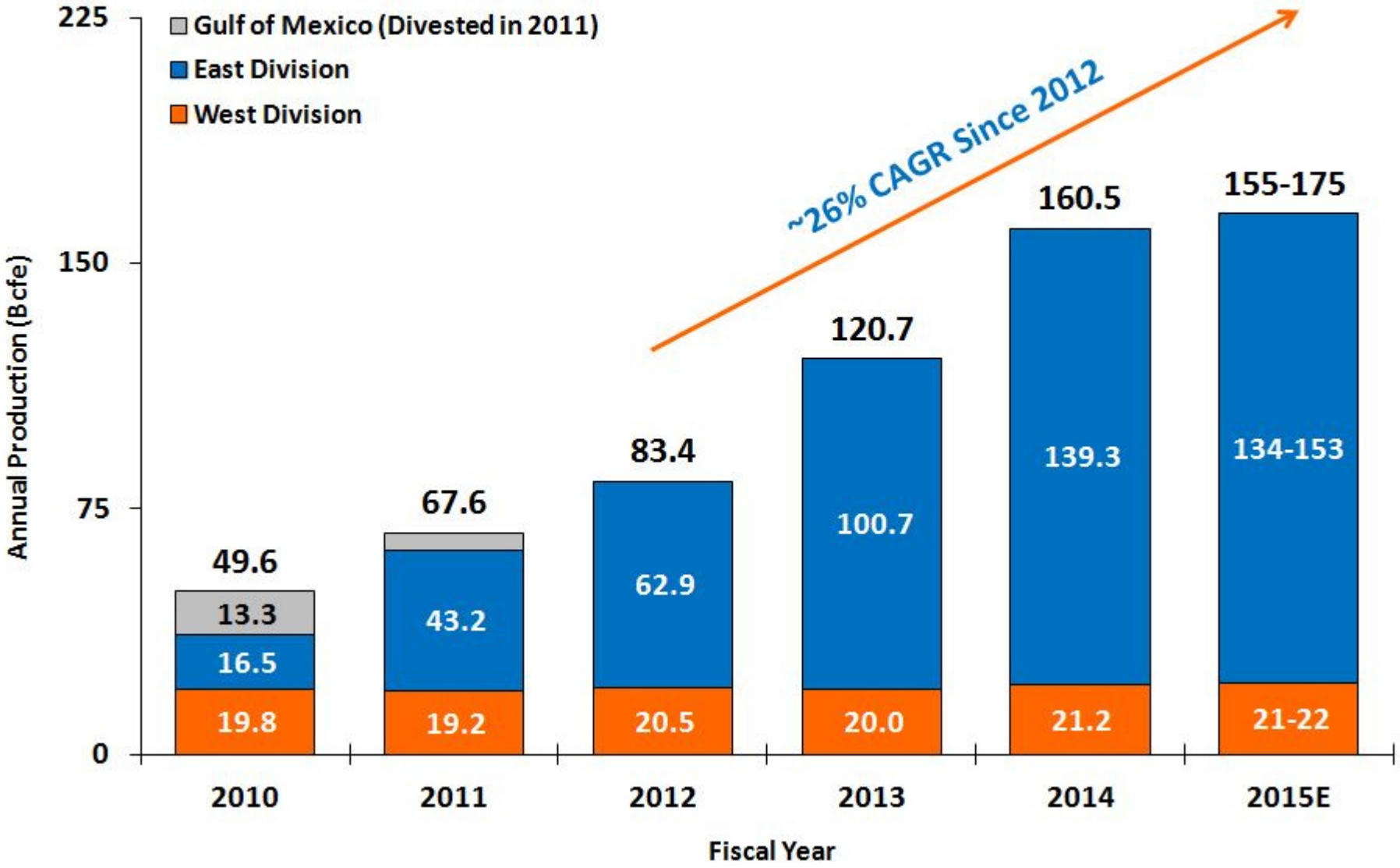


Fiscal Years	3-Year F&D Cost[1] ($/Mcfe)
2007-2009	$5.35
2008-2010	$2.37
2009-2011	$2.09
2010-2012	$1.87
2011-2013	$1.67
2012-2014	$1.38

- **2014 F&D Cost = $1.15**
  - Marcellus F&D: $1.00
- **327% Reserve Replacement Rate**
- **73% Proved Developed**

(1) Represents a three-year average U.S. finding and development cost.

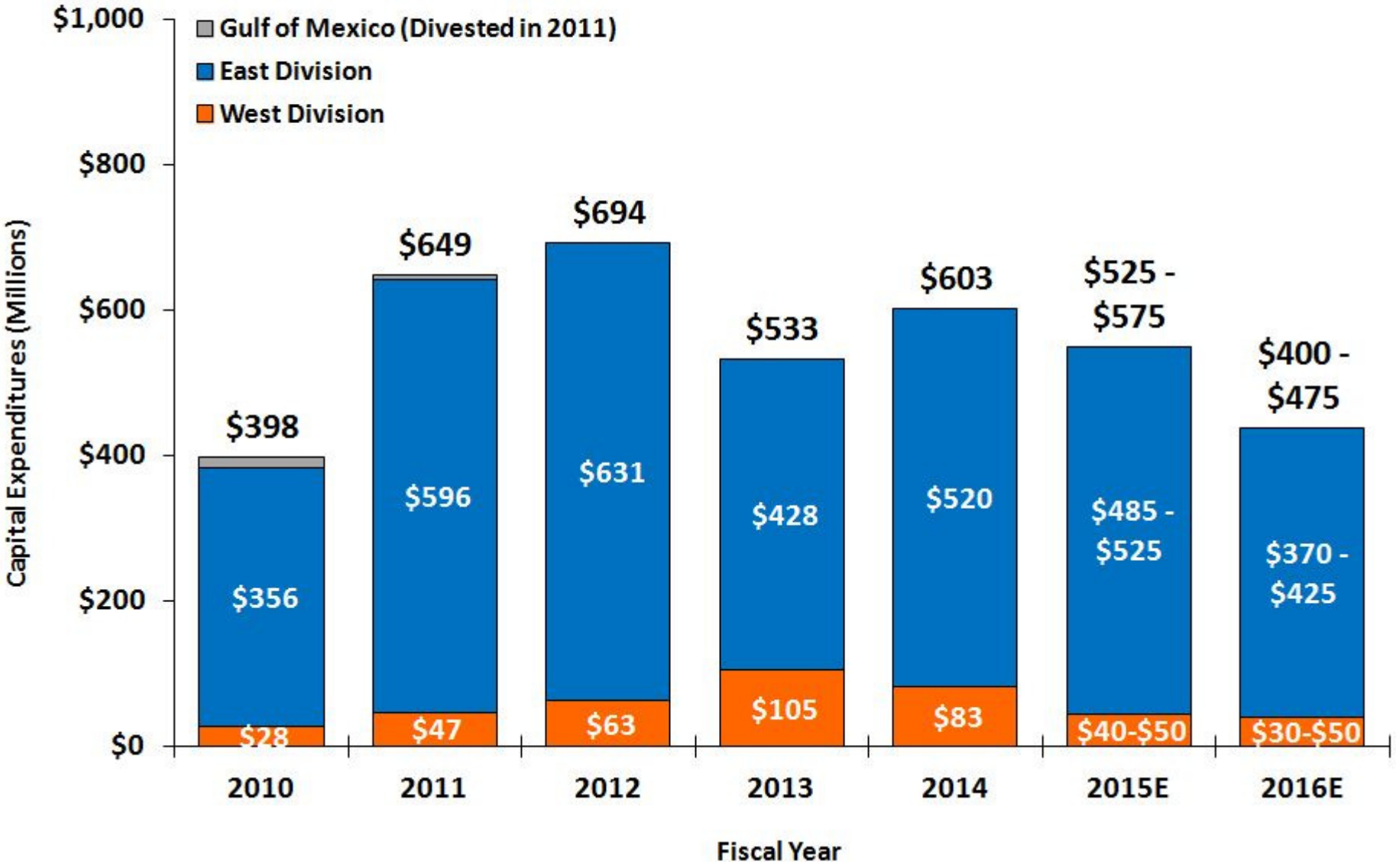
Marcellus Shale Driving Production Growth



Disciplined Capital Spending

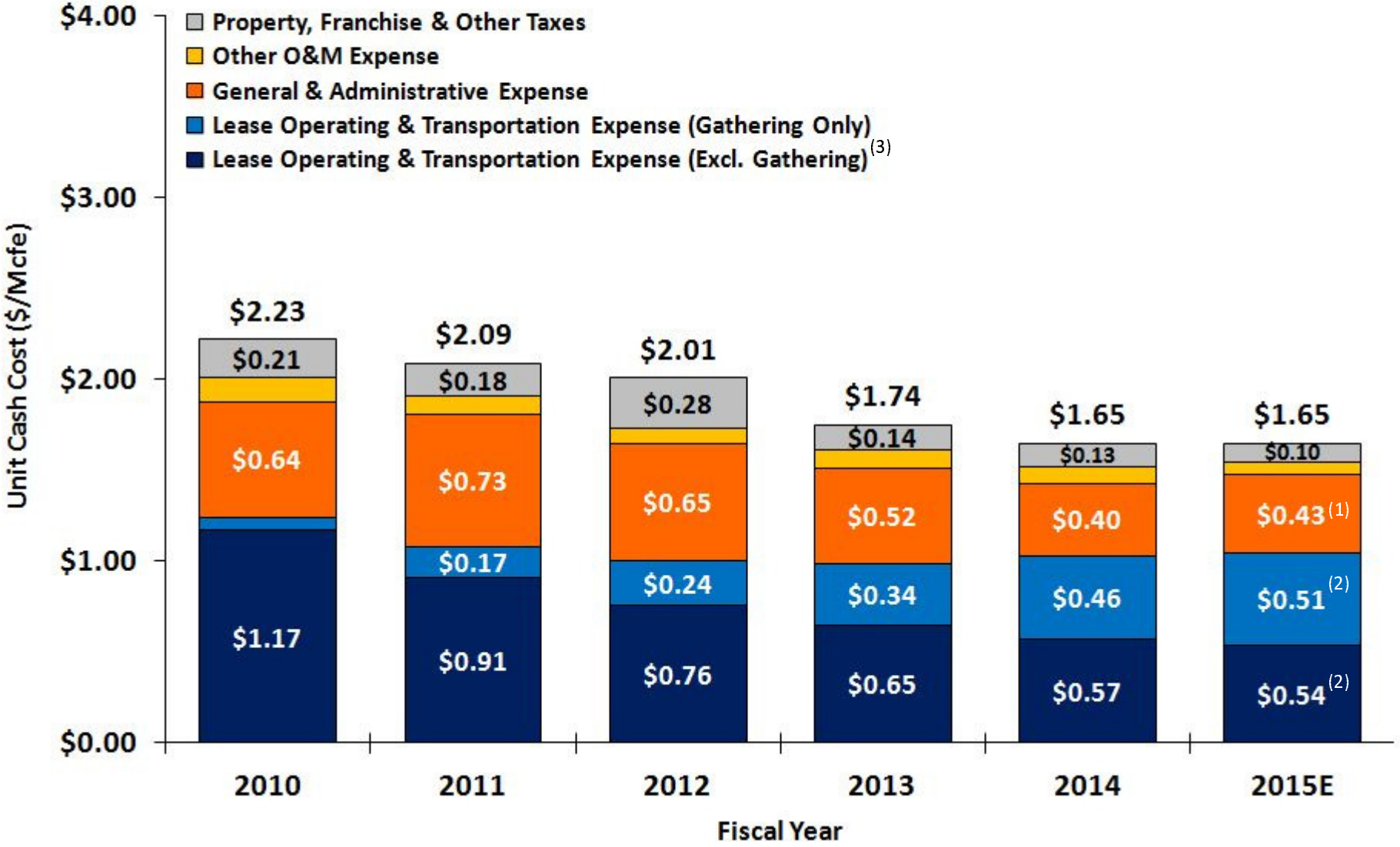
SENECA RESOURCES

Upstream



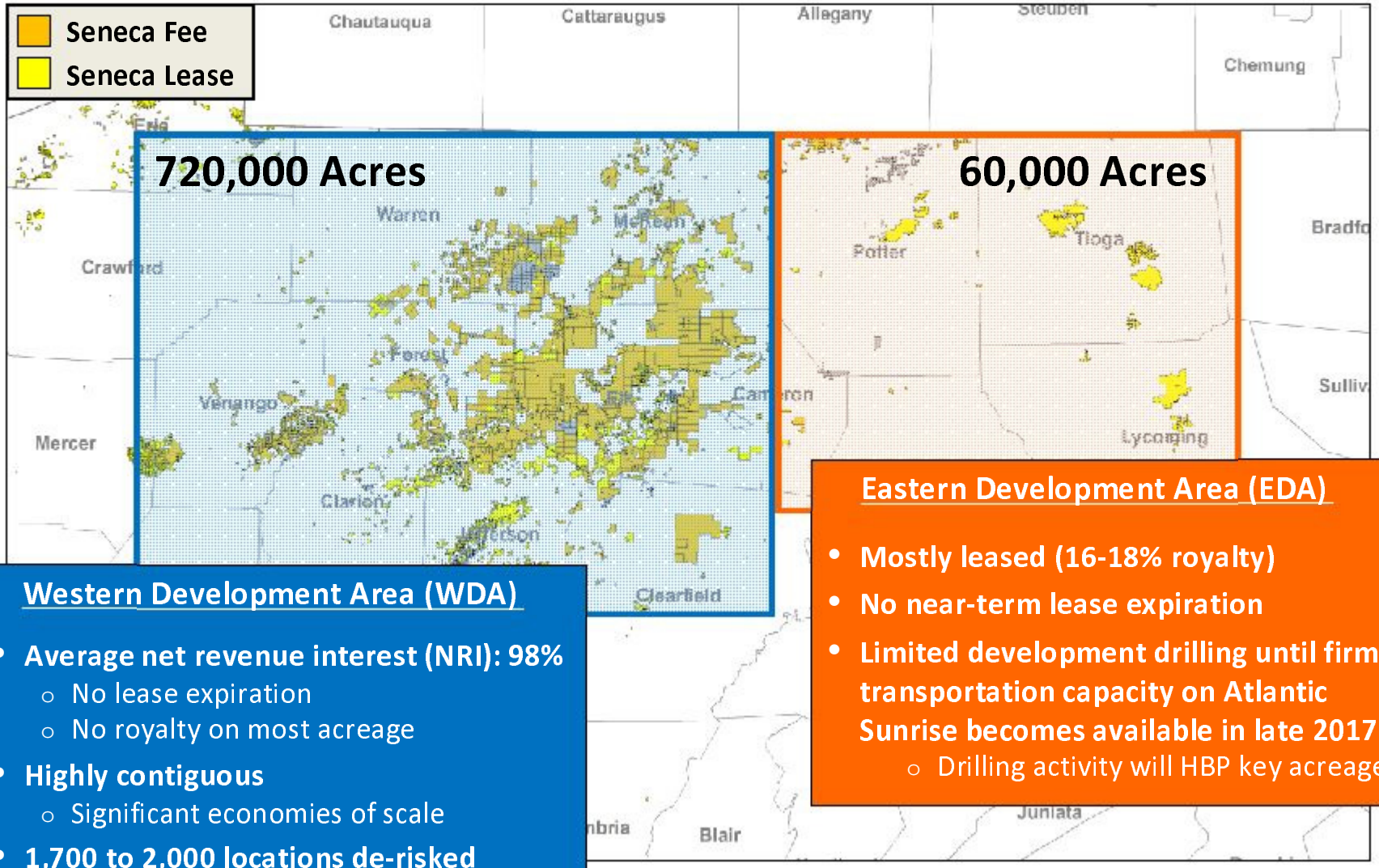
Highly Competitive Cost Structure

Upstream



(1) Represents the midpoint of current General & Administrative Expense guidance of $0.40 to $0.45 per Mcfe for fiscal 2015.
(2) The total of the two LOE components represents the midpoint of current LOE guidance of $1.00 to $1.10 per Mcfe for fiscal 2015.
(3) The cost of firm transportation is reflected in price realizations (a deduction to gross revenues). As such, it is not included in LOE.

Marcellus Shale: Prolific Pennsylvania Acreage



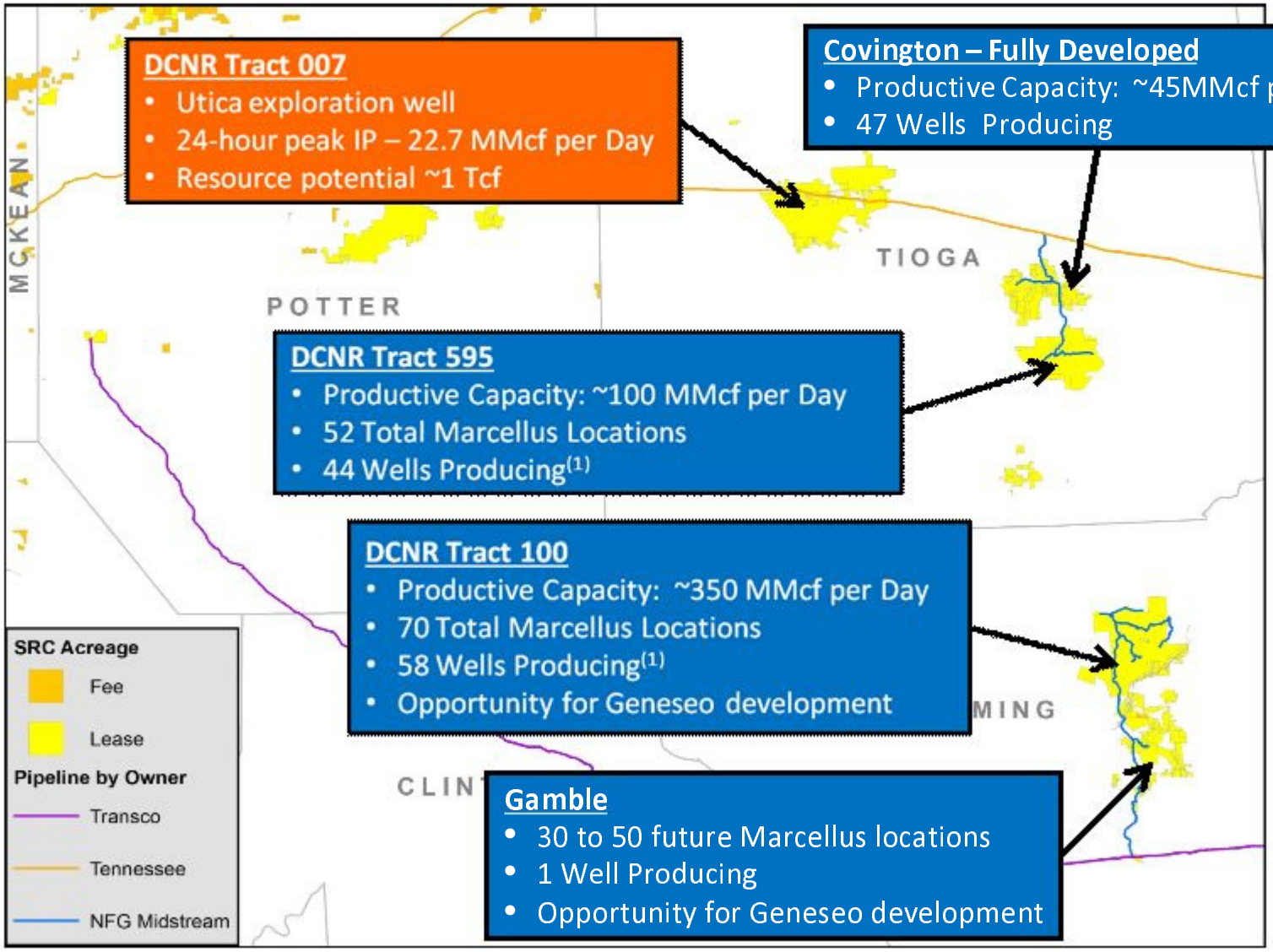
Western Development Area (WDA)

- **Average net revenue interest (NRI): 98%**
  - No lease expiration
  - No royalty on most acreage
- **Highly contiguous**
  - Significant economies of scale
- **1,700 to 2,000 locations de-risked**

Eastern Development Area (EDA)

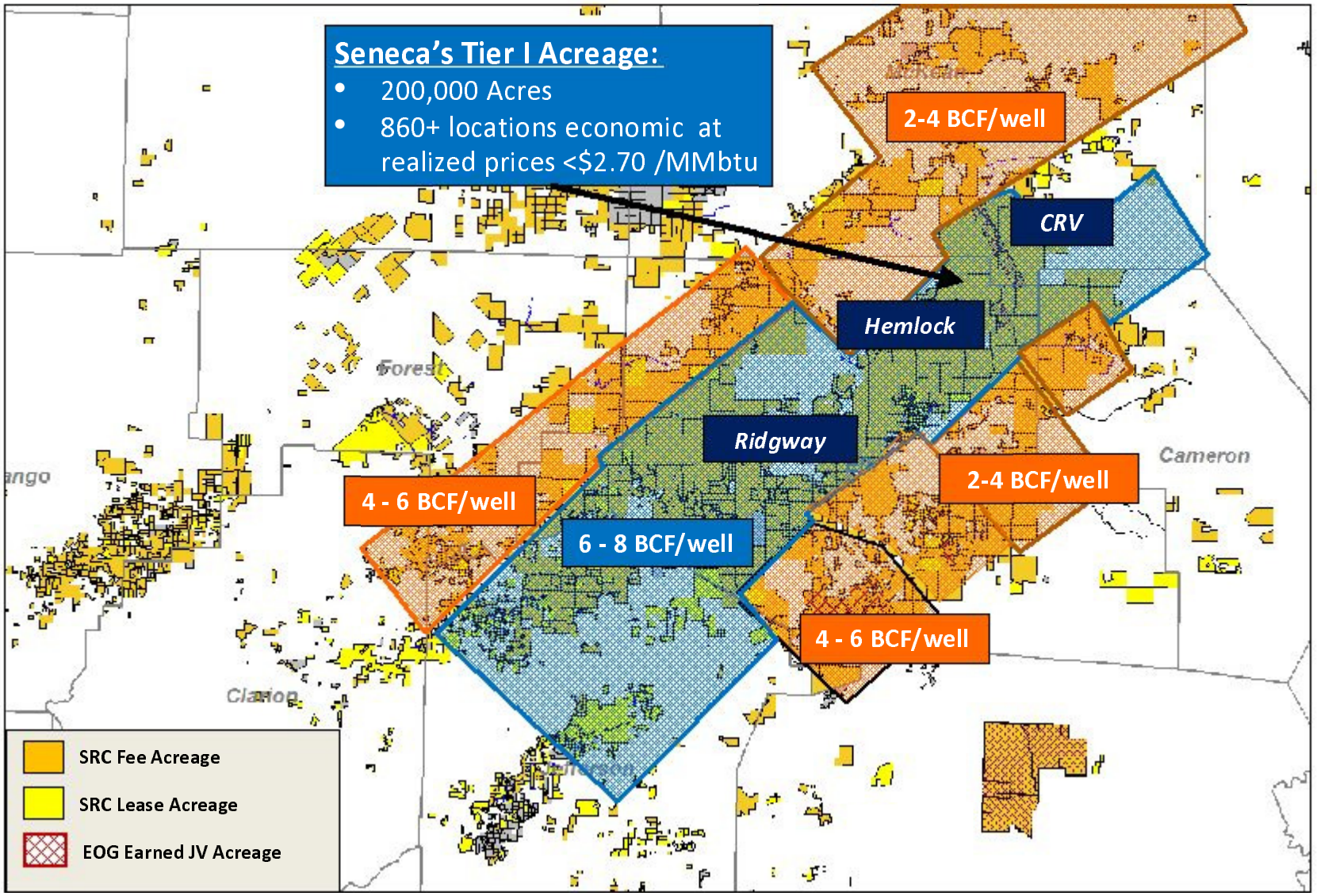
- **Mostly leased (16-18% royalty)**
- **No near-term lease expiration**
- **Limited development drilling until firm transportation capacity on Atlantic Sunrise becomes available in late 2017**
  - Drilling activity will HBP key acreage

EDA Delivering Significant Growth



(1) One well included in the total for both Tract 595 and Tract 100 is drilled into and producing from the Geneseo Shale.

Focusing on WDA Development



Note: Assumes 6,000' treated lateral length.

Clermont/Rich Valley (CRV) Area

Marcellus Well Results

EDA Development Wells:

Area	Producing Well Count	Average IP Rate (MMcfd)	Average 7-Day (MMcf/d)	Average Treatable Lateral Length (ft)
Covington Tioga County	**47**	**5.2**	**4.7**	**4,023'**
Tract 595 Tioga County	**43**(1)	**7.4**	**6.1**	**4,765'**
Tract 100 Lycoming County	**57**(1)	**16.8**	**14.8**	**5,270'**

WDA Development Wells:

Area	Producing Well Count	Average IP Rate (MMcfd)	Average 7-Day (MMcf/d)	Average Treatable Lateral Length (ft)
Clermont/Rich Valley (CRV) & Hemlock *Elk, Cameron & McKean counties*	**25**(2)	**7.7**	**6.9**	**5,558'**

(1) Does not include a well drilled into and producing from the Geneseo Shale.

(2) Excludes 3 wells drilled and completed without sufficient production data for inclusion in table. Also excludes 2 wells now operated by Seneca that were drilled by a prior operator as part of a joint-venture.

Marcellus Drilling and Completion Efficiencies

Fiscal 2012 Average Development Well

$8.7 MM Well Cost

- **Lateral Length:** 5,100 ft
- **Measured Depth:** 13,700 ft
- **Completion Stages:** 20

Fiscal 2015[1] Average Development Well

$6.3 MM Well Cost

- **Lateral Length:** 7,200 ft
- **Measured Depth:** 14,300 ft
- **Completion Stages:** 38

Drilling Cost per Foot[2]

Completion Cost per Stage[2] (000s)

(1) Estimated fiscal year-to-date through March 31, 2015.

(2) Includes dollars spent to drill and complete development wells only. Excludes exploration and delineation wells.

Marcellus Shale Program Economics

~2,000 WDA Locations Economic Below $4/MMbtu

	Prospect	Product	Locations Remaining to Be Drilled	Completed Lateral Length (ft)	Average EUR (Bcf)	BTU	$4.00 Dawn/Nymex IRR %(1)	$3.50 Dawn/Nymex IRR %(1)	15% IRR (1) Realized Price
EDA	DCNR 100	Dry Gas	13	5,582	13-14	1030	86%	57%	$1.83
EDA	Gamble	Dry Gas	28	4,605	10.5-11.5	1030	58%	50%	$2.07
WDA	Clermont - Rich Valley	Dry Gas	142	7,000	7.5-8.5	1050	41%	26%	$2.31
WDA	Hemlock	Dry Gas	157	7,000	6.5-7.5	1050	29%	18%	$2.57
WDA	Ridgway	Dry Gas	564	7,000	6-7	1111	26%	15%	$2.69
WDA	Remaining Tier 1	Dry Gas	1,020	7,000	5.5-6.5	1030 - 1100	21%	12%	> $3.00
WDA	Future Resource(2)	Dry & Wet Gas	1,620	7,000	5.5-6.5	1030 - 1350	14%	8%	> $3.25

(1) Internal Rate of Return (IRR) is pre-tax and includes estimated well costs under current cost structure, LOE, and Gathering tariffs anticipated for each prospect.
(2) Additional delineation required.

WDA Mineral Interests Significantly Enhance Returns

Clermont/Rich Valley Example

($/Mcf)	The Seneca Advantage 0% Royalty	Producer Paying 15% Royalty
Realized Price	**$ 2.31**	**$ 2.31**
Less: Royalty Payment	(0.00)	(0.35)
Less: Cash Operating Expenses	(0.65)	(0.65)
Cash Margin	**$ 1.66**	**$ 1.31**
Before Tax IRR (1)	***15%***	***8%***

A producer burdened by a 15% royalty would require a **$0.41 higher realized price** to achieve same level of economics as Seneca Resources

(1) Internal Rate of Return (IRR) includes estimated well costs under current cost structure, LOE, and Gathering tariffs anticipated for each prospect.

Adding Long-Term Firm Transport to the Portfolio

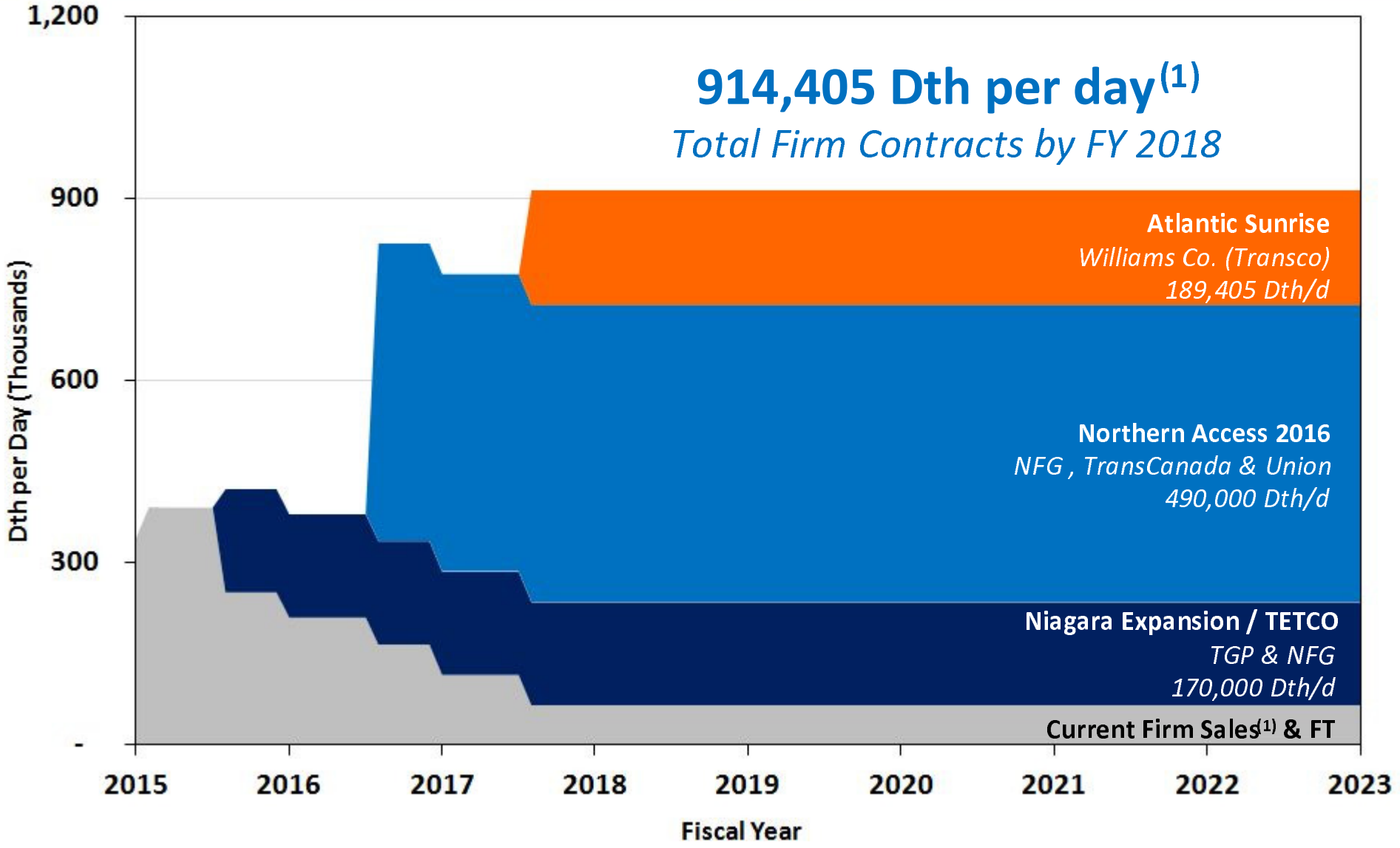
Project (Counterparty)	In-Service Date	Contract Term	Delivery Market	FT Capacity (Dth/day) Fiscal 2015	Fiscal 2016	Fiscal 2017	Fiscal 2018	Matched Firm Sales Contracts
Northeast Supply Diversification Project (TGP)	Nov. 2012	15 years	Canada	50,000	50,000	50,000	50,000	**Executed Contracts** 50,000 Dth/d for 10 years
Niagara Expansion/ TETCO (TGP & NFG)	Nov. 2015	15 years	Canada	---	158,000	158,000	158,000	**Executed Contracts** 140,000 Dth/d for 15 years
			TETCO	---	12,000	12,000	12,000	
Northern Access 2016 (NFG/ TransCanada/ Union)	Late 2016	15 years	Canada	---	---	350,000	350,000	**Executed Contracts** 75,000 Dth/d for 7.5 years *Evaluating Further Opportunities*
			TGP 200 (NY)	---	---	140,000	140,000	
Atlantic Sunrise (Transco)	Nov. 2017	15 years	Mid-Atlantic/ Southeast	---	---	---	189,405	**Executed Contracts** 189,405 Dth/d for first 5 years(1)
Total Firm Transportation Capacity				**50,000**	**220,000**	**710,000**	**899,405**	
Weighted Average Reservation Charge per Dth (2)				**$0.29**	**$0.42**	**$0.56**	**$0.59**	

(1) A large majority of the executed firm sales agreements continue for the remainder of the firm transportation contract term.

(2) Excludes throughput-based commodity charges, fuel charges and other surcharges.

Significant Base of Long-Term Firm Contracts

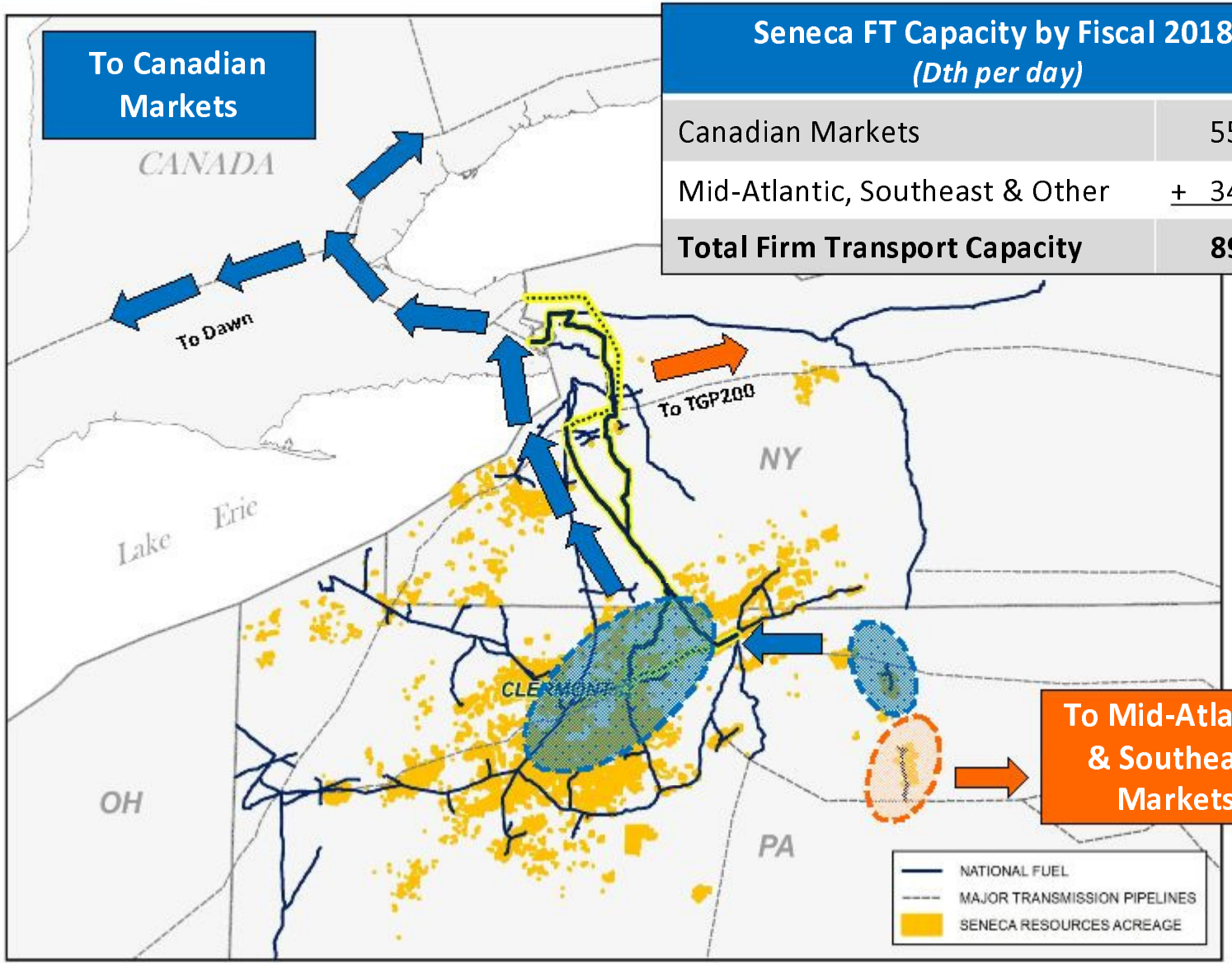
Upstream



(1) Includes base firm sales contracts not tied to firm transportation capacity.

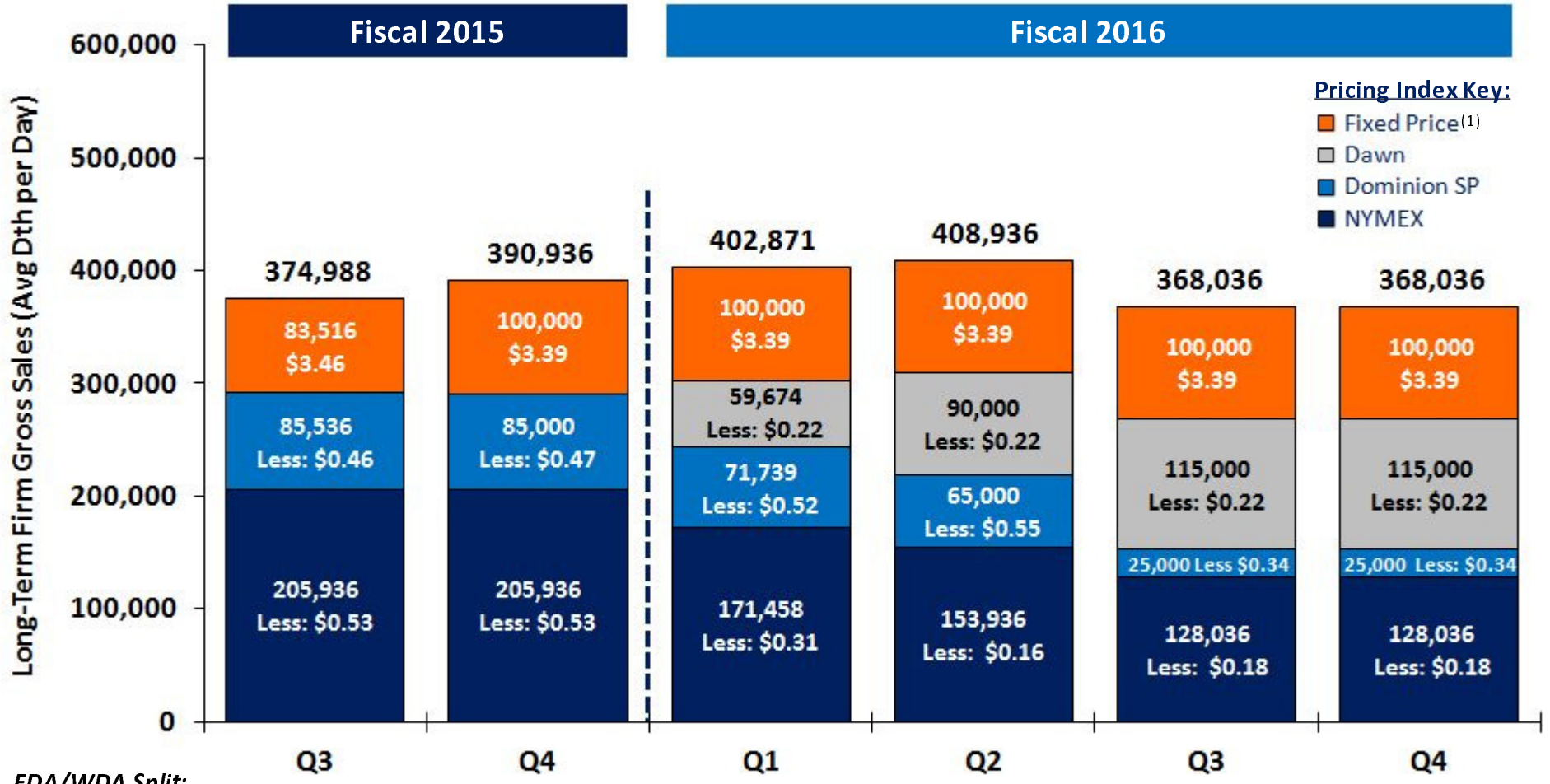
Reaching High Value Markets

Seneca FT Capacity by Fiscal 2018 *(Dth per day)*	
Canadian Markets	558,000
Mid-Atlantic, Southeast & Other	+ 341,405
Total Firm Transport Capacity	**899,405**



Firm Sales Provide Market for Appalachian Production

Upstream



EDA/WDA Split:

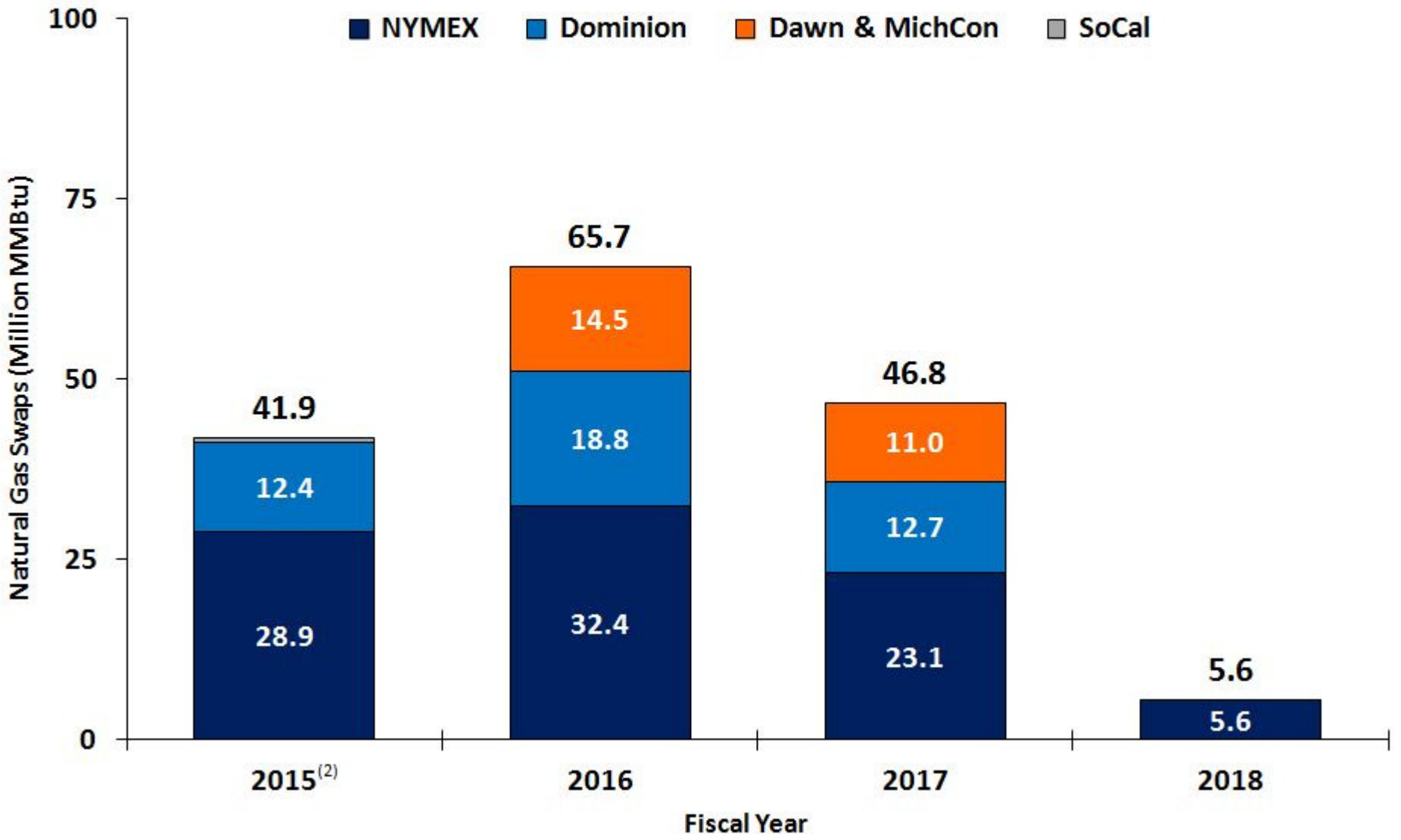
	Q3	Q4	Q1	Q2	Q3	Q4
EDA (2)	280,036 /d	280,036 /d	226,993 /d	200,036 /d	160,036 /d	160,036 /d
WDA (2)	94,952 /d	110,900 /d	175,878 /d	208,900 /d	208,000 /d	208,000 /d

(1) Includes new 50,000 Dth per day firm sales contract starting May 1, 2015 at $3.00 per Dth.

(2) EDA and WDA carry an average net revenue interest (NRI) of 82% - 84% and 98%, respectively.

Note: Values shown represent the price or differential to a reference price (netback price) at the point of sale, including the cost of all related downstream transportation.

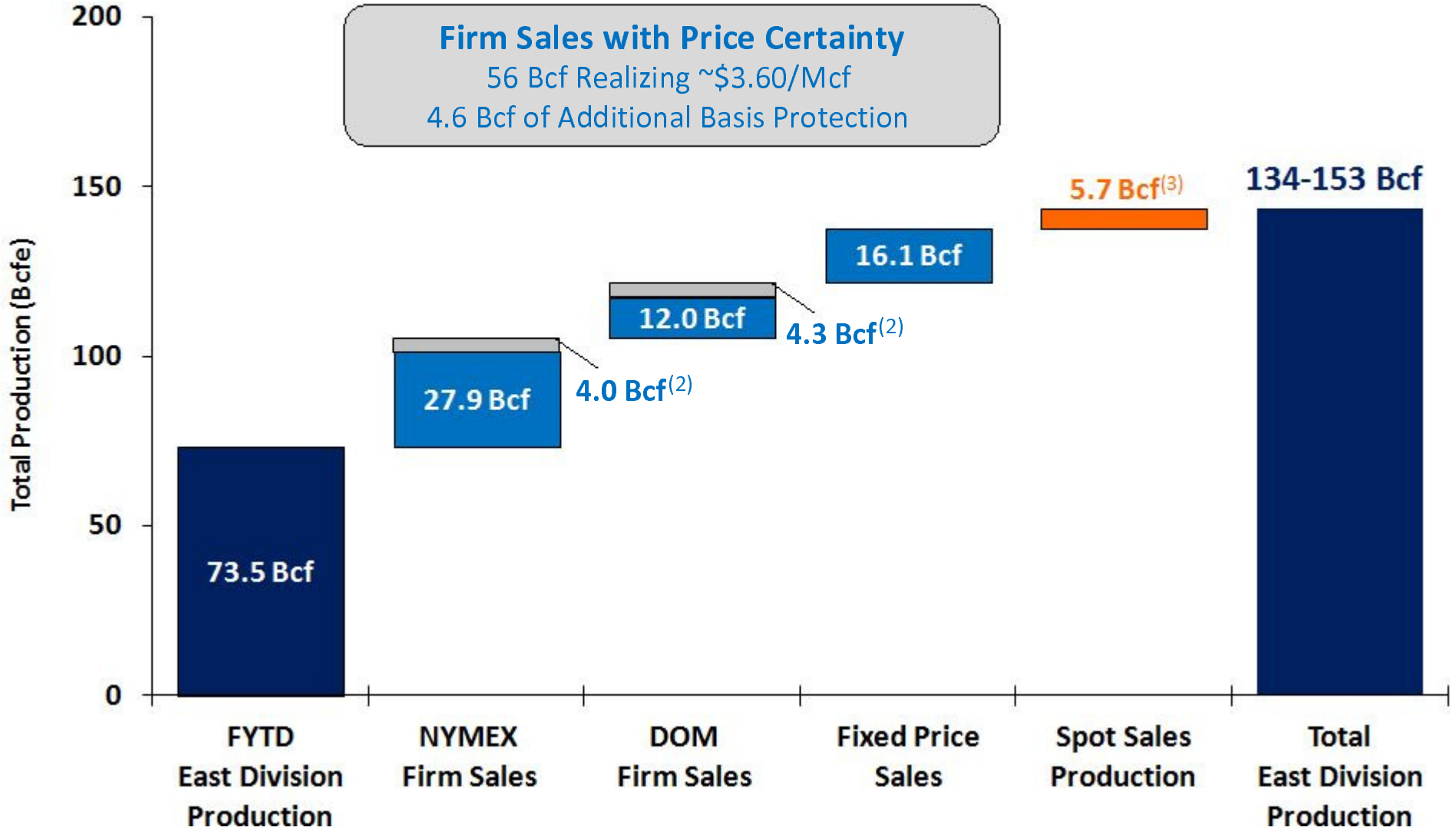
Natural Gas Financial Hedge Positions[1]



(1) Excludes fixed price physical firm sales.

(2) For the remaining six months of fiscal 2015. A table of volumes and average hedge prices by index are included in the Appendix.

FY 2015 Production – Firm Sales & Spot Exposure



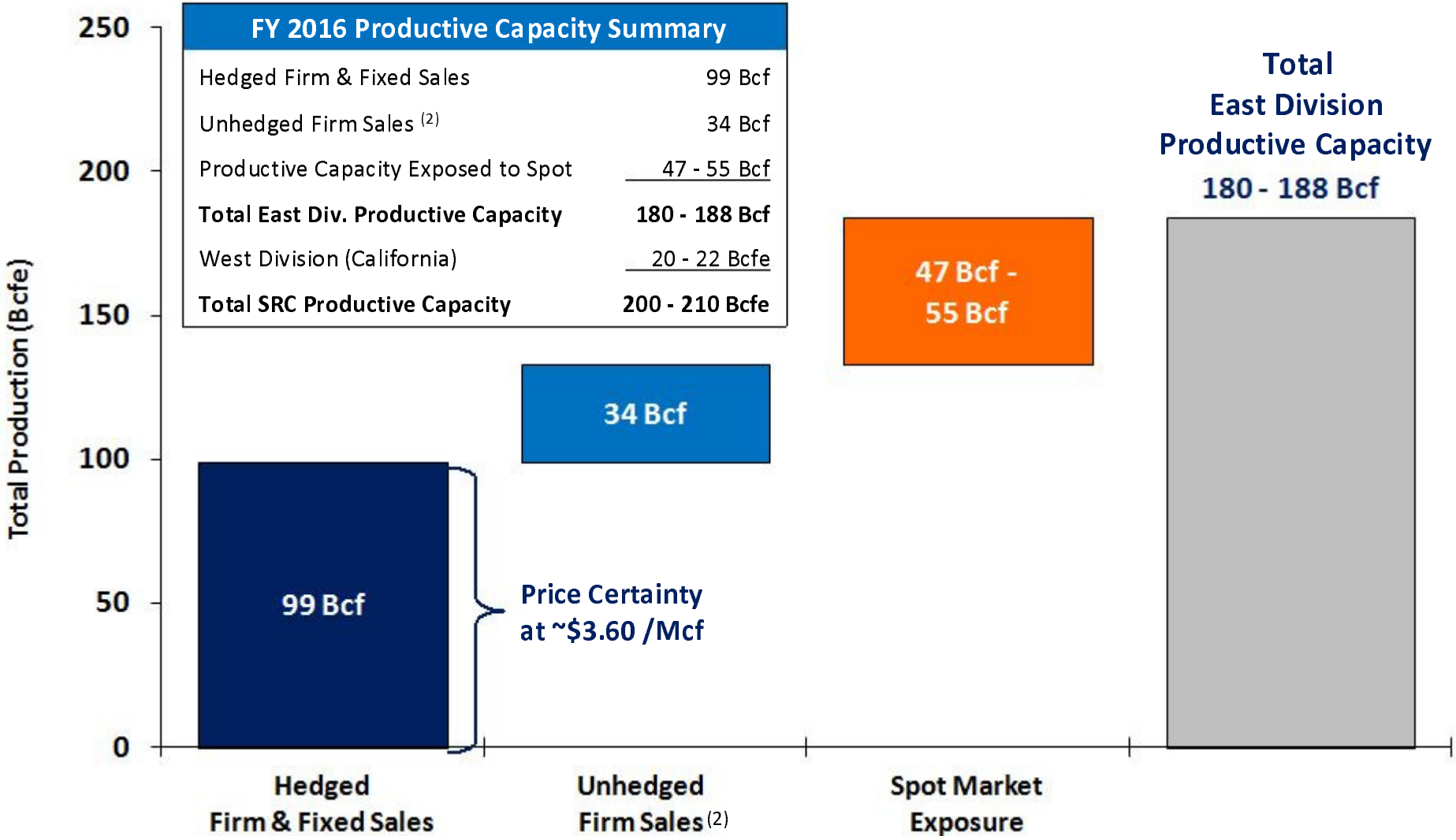
(1) Spot price assumptions reflected in fiscal 2015 earnings guidance range.

(2) Indicates firm sales not backed by financial hedges. DOM Firm Sales include 3.7 Bcf of non-operated WDA production volumes.

(3) EPS guidance assumes spot volumes are sold at $1.75 - $2.00 per Mcf.

FY 2016 Productive Capacity[1]

FY 2016 Productive Capacity Summary	
Hedged Firm & Fixed Sales	99 Bcf
Unhedged Firm Sales [2]	34 Bcf
Productive Capacity Exposed to Spot	47 - 55 Bcf
Total East Div. Productive Capacity	**180 - 188 Bcf**
West Division (California)	20 - 22 Bcfe
Total SRC Productive Capacity	**200 - 210 Bcfe**



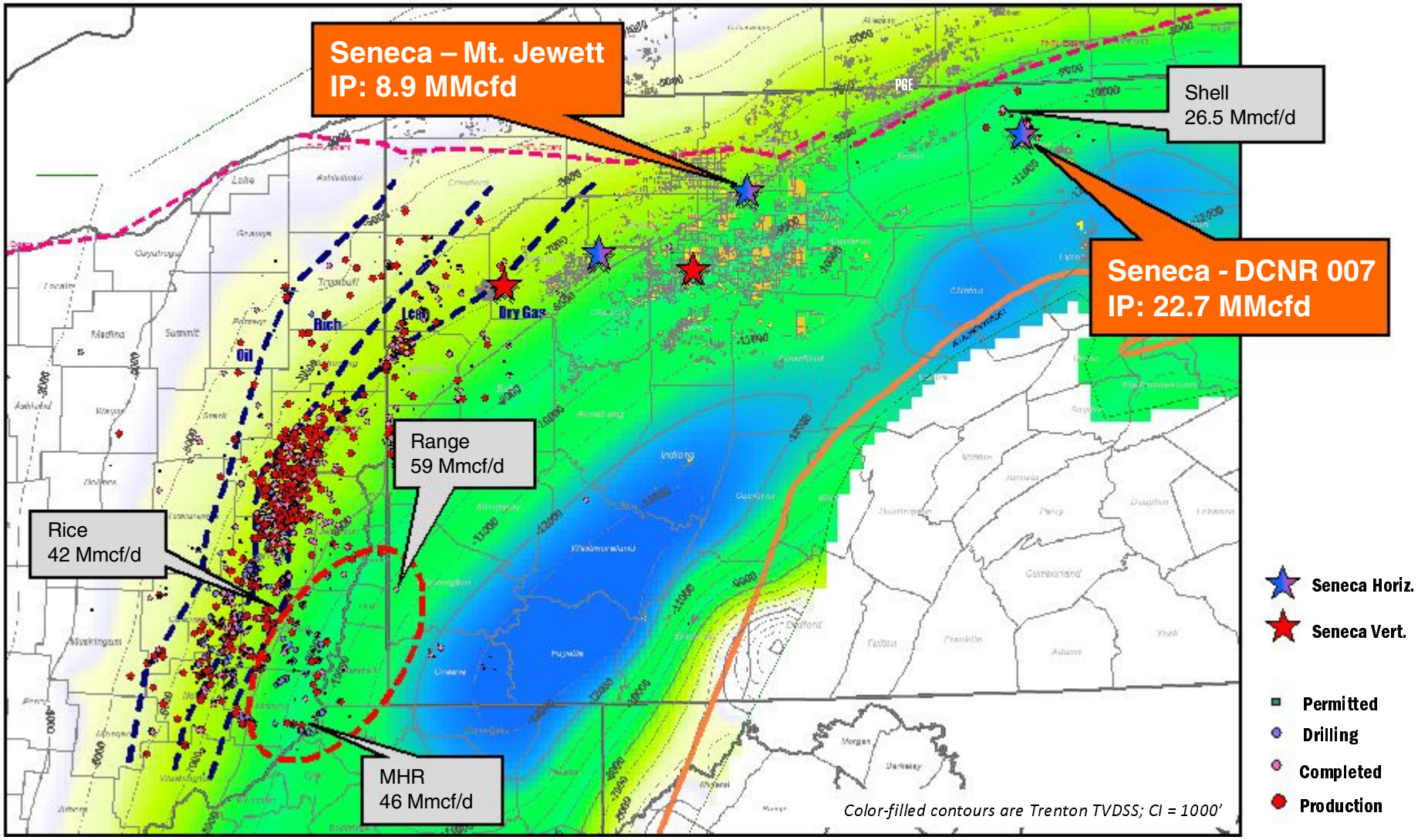
(1) Productive capacity reflects firm sales commitments and assumes no price-related curtailments on projected production exposed to local Appalachian spot pricing. Productive capacity is not intended to reflect production guidance for fiscal 2016.

(2) Unhedged firm sales includes non-operated WDA production volumes.

Utica/Point Pleasant: Industry Activity

SENECA RESOURCES

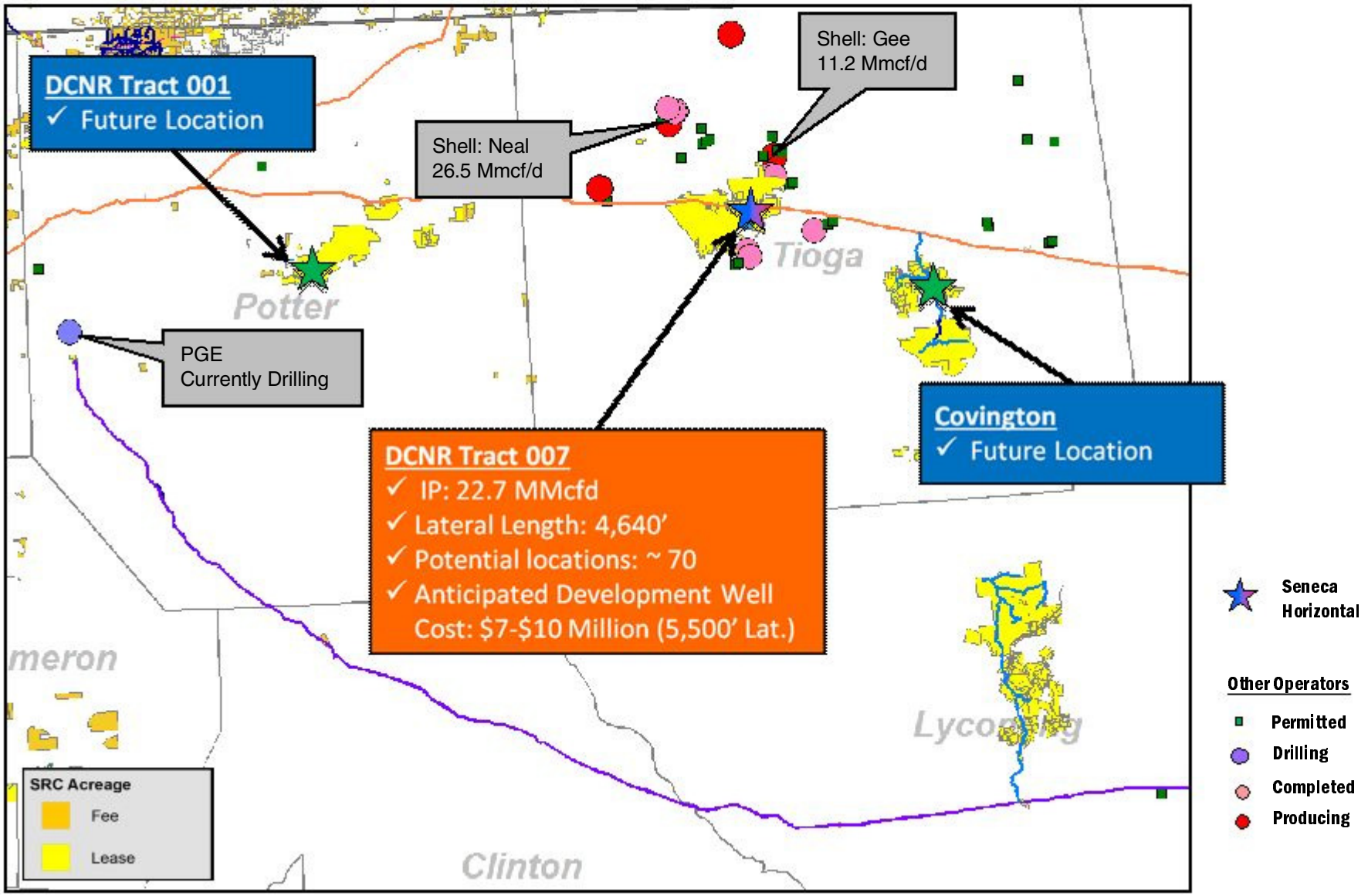
Upstream



Utica/Point Pleasant Shale: EDA Opportunities

SENECA RESOURCES

Upstream



California: Stable Production; Modest Growth

East Coalinga
Temblor Formation
Primary

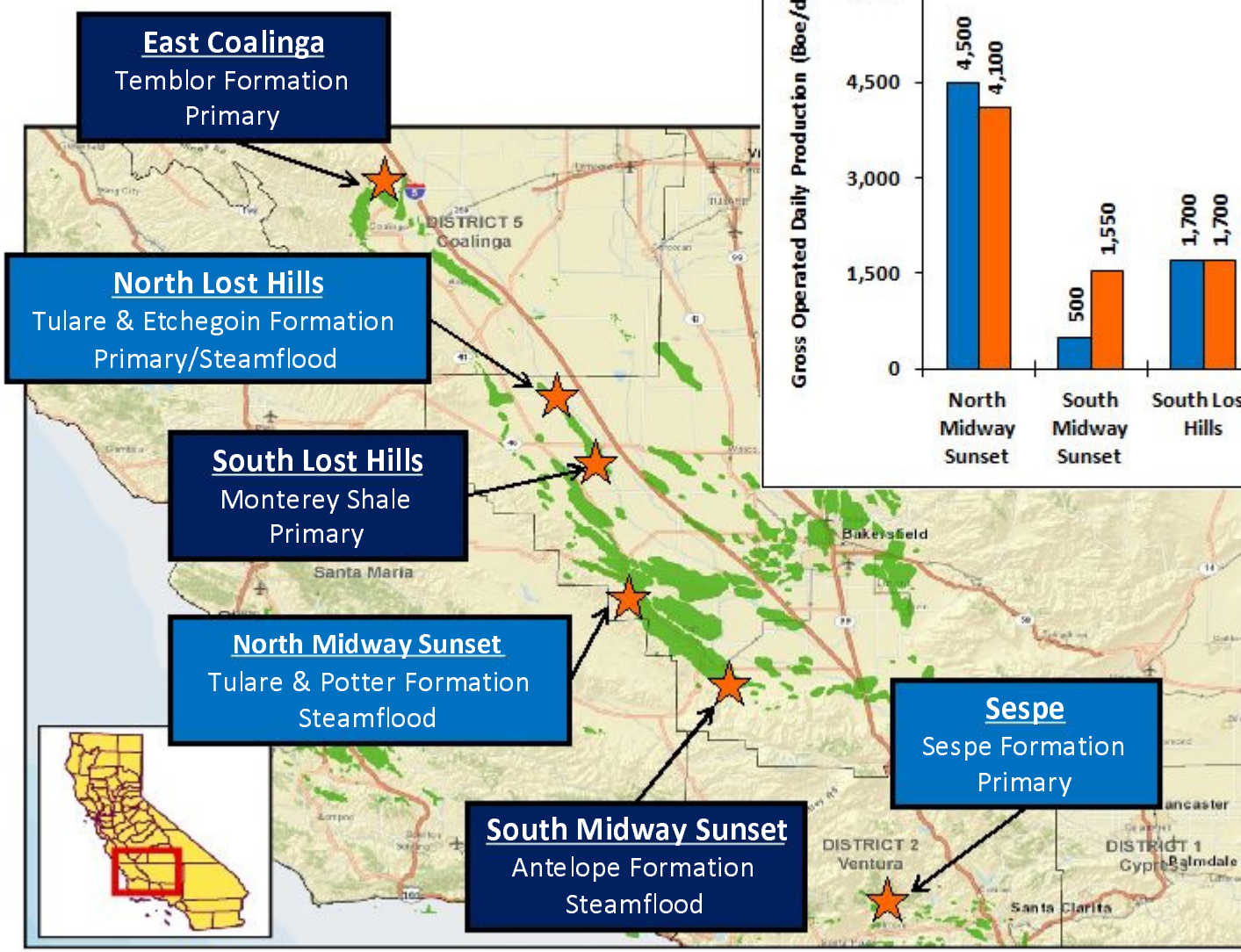
North Lost Hills
Tulare & Etchegoin Formation
Primary/Steamflood

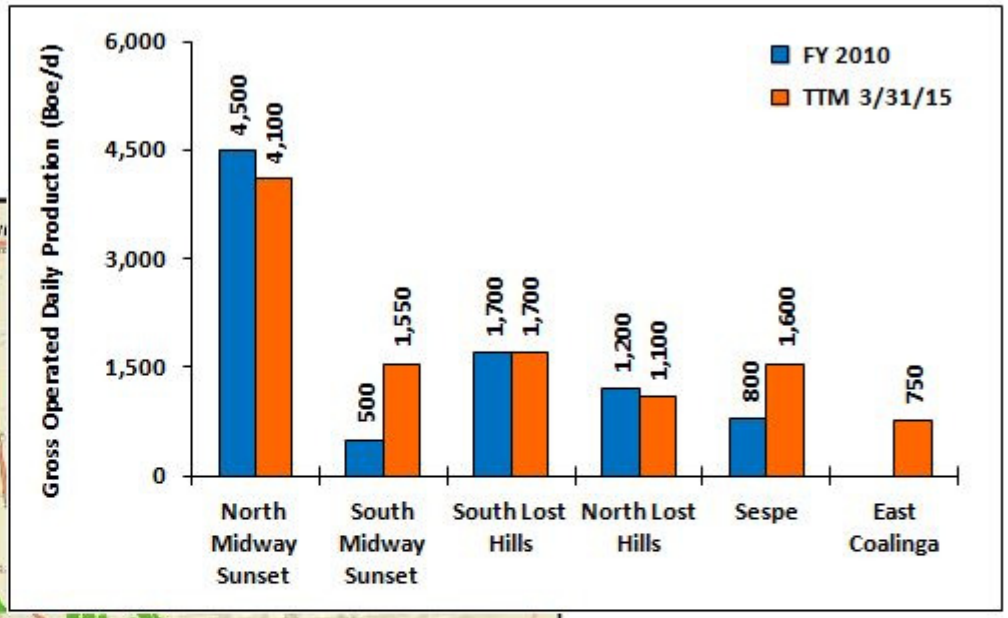
South Lost Hills
Monterey Shale
Primary

North Midway Sunset
Tulare & Potter Formation
Steamflood

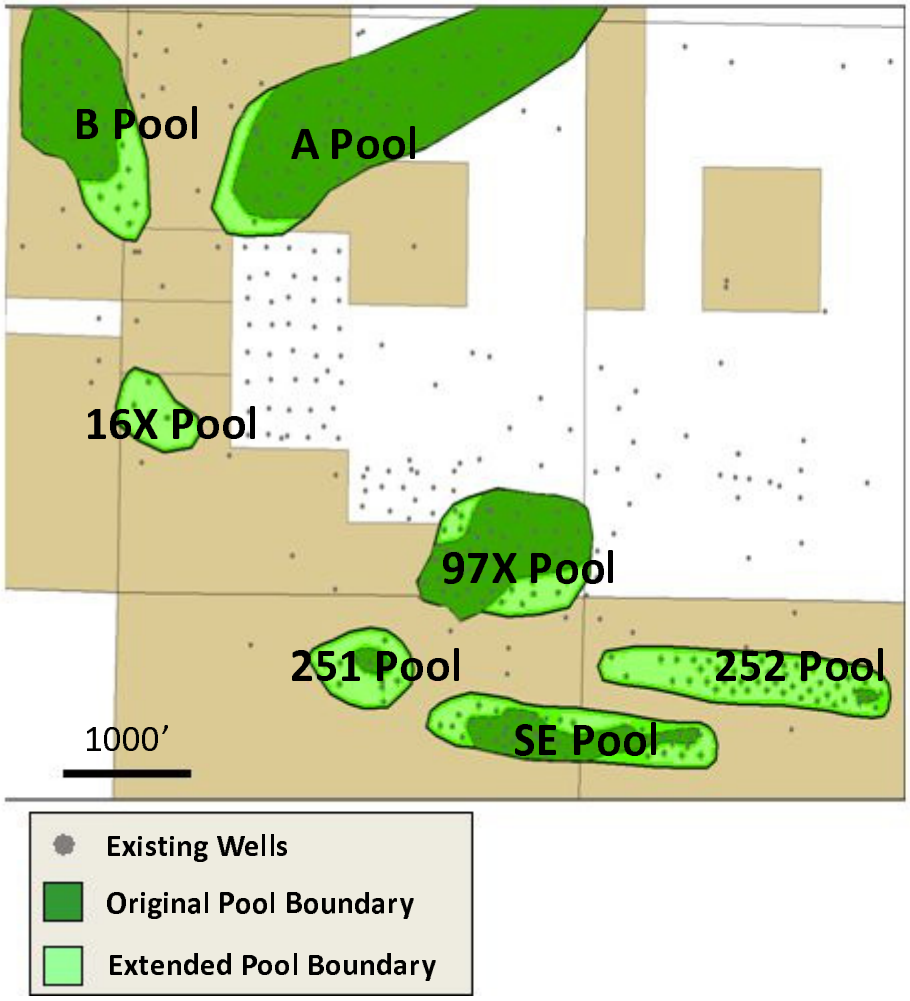
South Midway Sunset
Antelope Formation
Steamflood

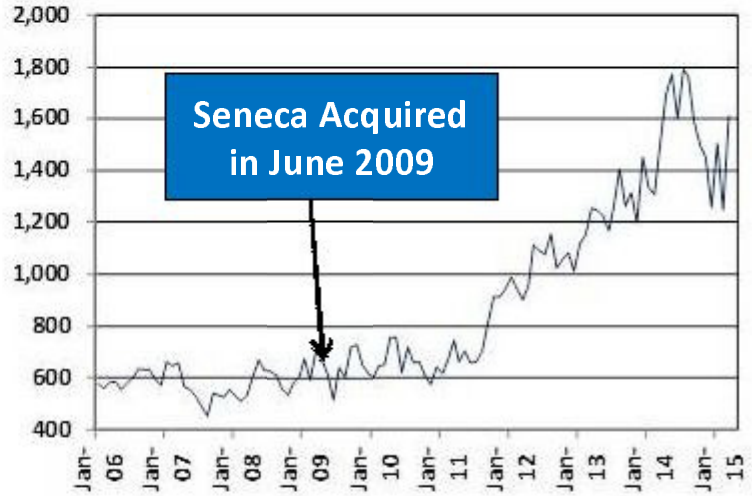
Sespe
Sespe Formation
Primary





South Midway Sunset Development





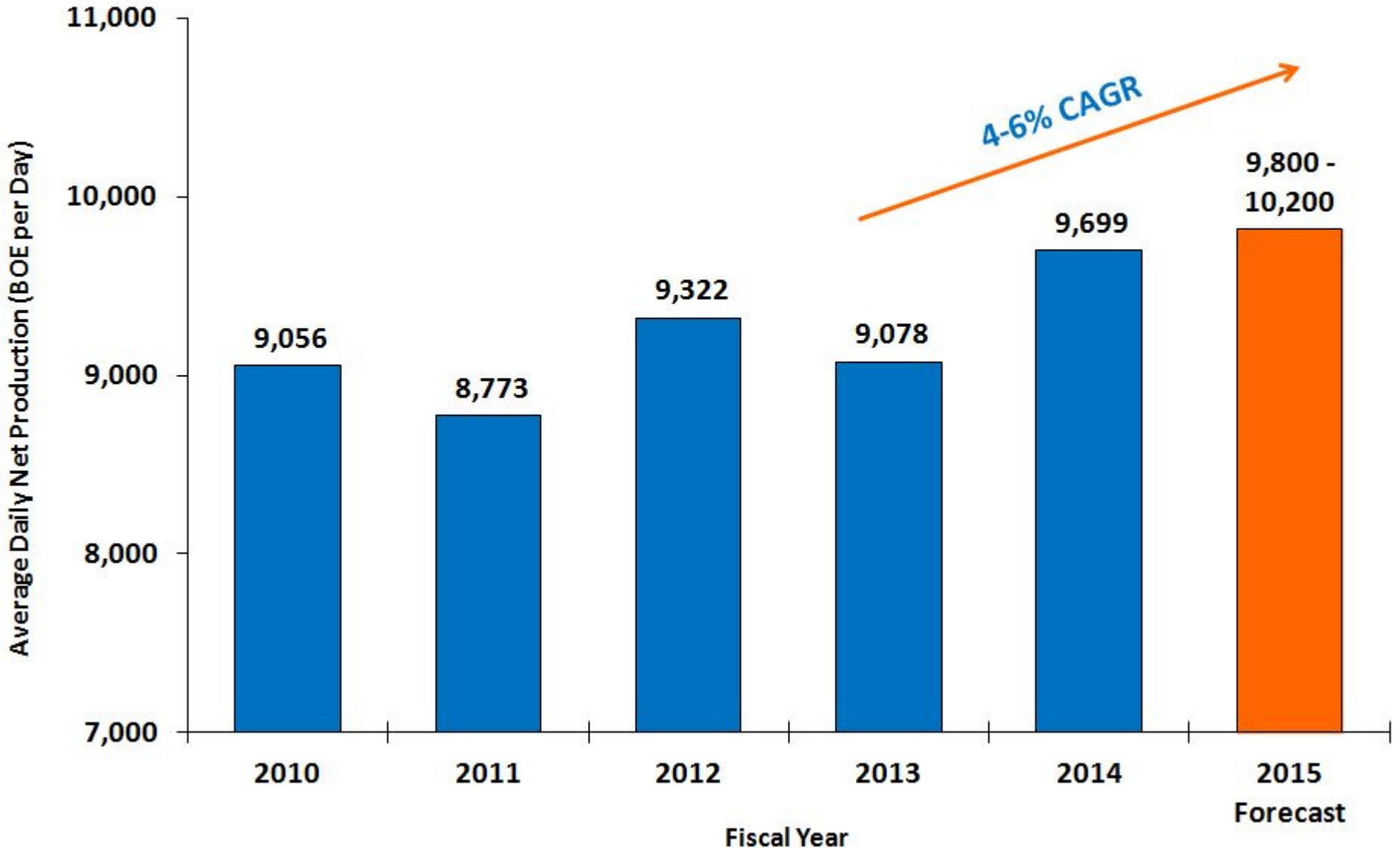
Highlights Since Acquisition

- Significantly increased daily production
- Drilled 135 new producers
- Added 3.8 MMBO of proven reserves
- Increased steam capacity by 600%
- Identified opportunities for additional pool development

Focused on High Return Opportunities

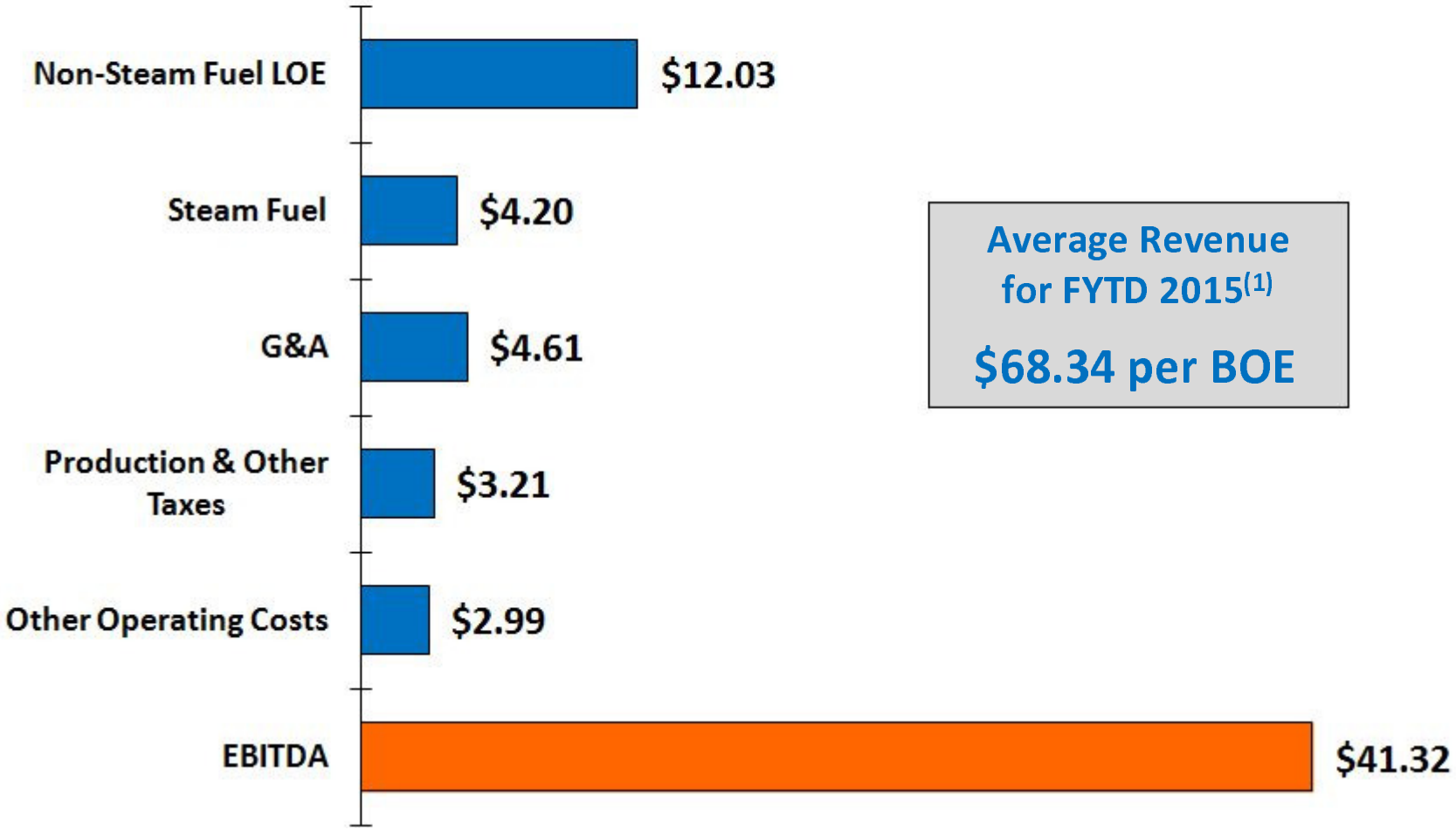
CALIFORNIA				
Field	Average Well Cost	Average EUR (MBO)	Estimated IRR @$55/Bbl	Fiscal 2015 Locations
South Midway Sunset	$250,000	39	57%	36
North Midway Sunset	$300,000	30	25%	15
East Coalinga	$420,000	29	15%	5

California: Modest Growth Anticipated in 2015



Strong Margins Support Significant Free Cash Flow

FYTD 2015 West Division EBITDA per BOE[(1)]



Average Revenue for FYTD 2015[(1)]

$68.34 per BOE

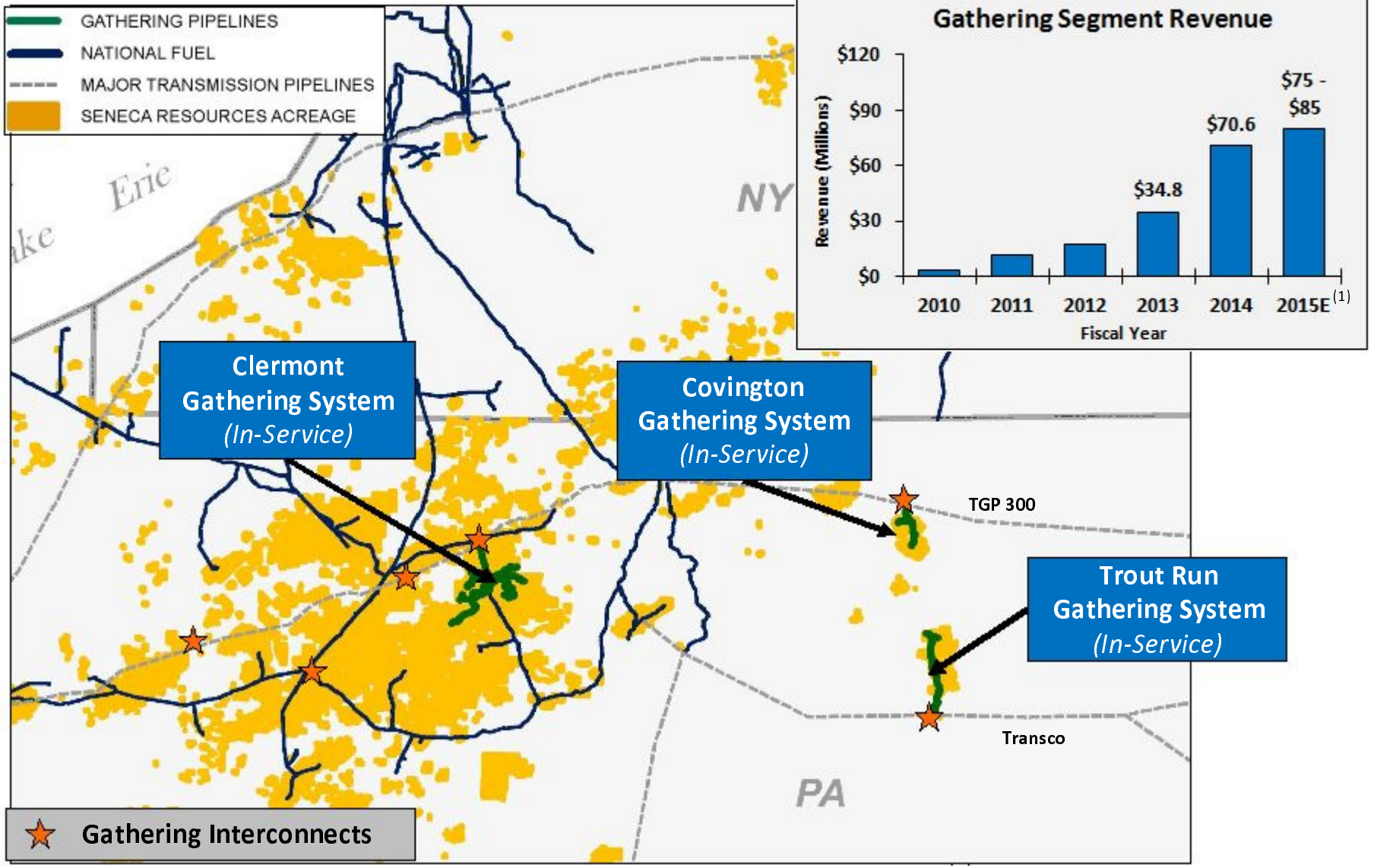
(1) Reflects the six month period ended March 31, 2015. Average revenue per BOE includes impact of hedging.

Midstream Overview

Pipeline & Storage
Gathering

Gathering is the First Step to Reaching a Market

Midstream



(1) Fiscal 2015 estimated revenue reflects projected throughput based on the range of Seneca's Fiscal 2015 production guidance (155-175 Bcfe).

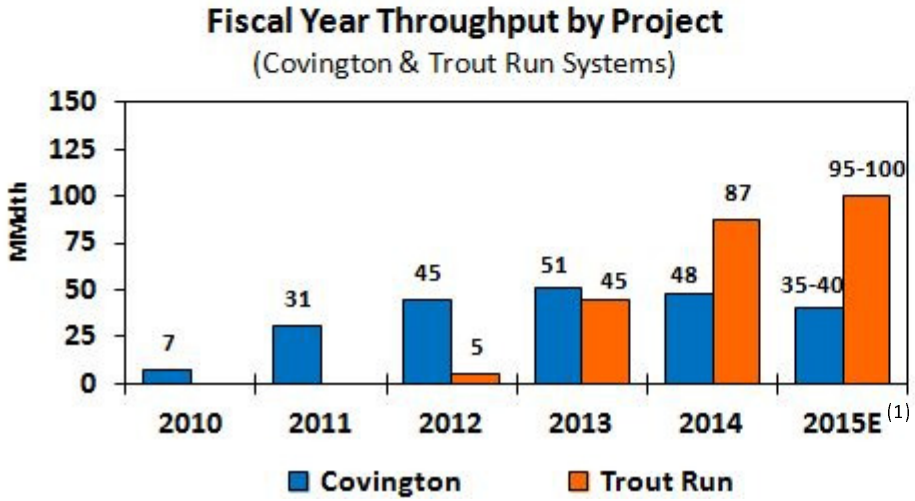
Gathering Supporting Seneca's EDA Production

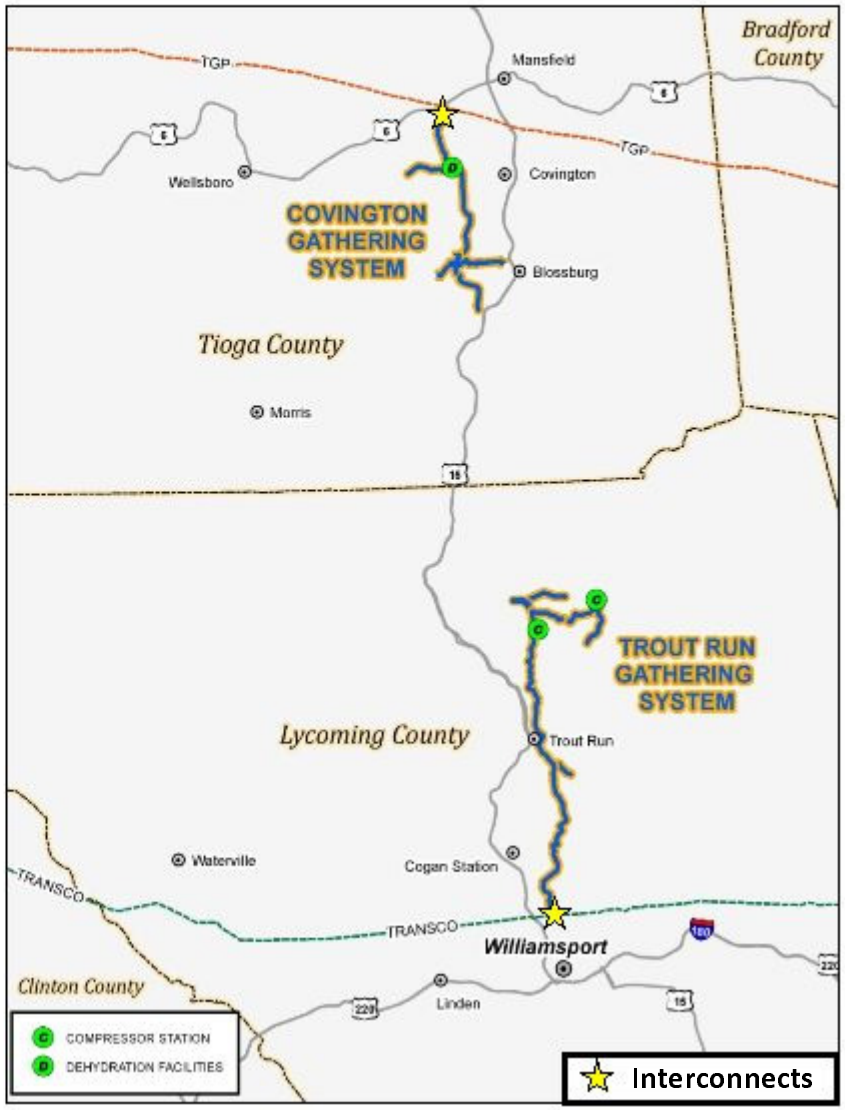
Covington Gathering System

- In-Service Date: November 2009
- Capacity: 220,000 Dth per day
- Interconnect: TGP 300
- Capital Expenditures (to date): $32 Million

Trout Run Gathering System

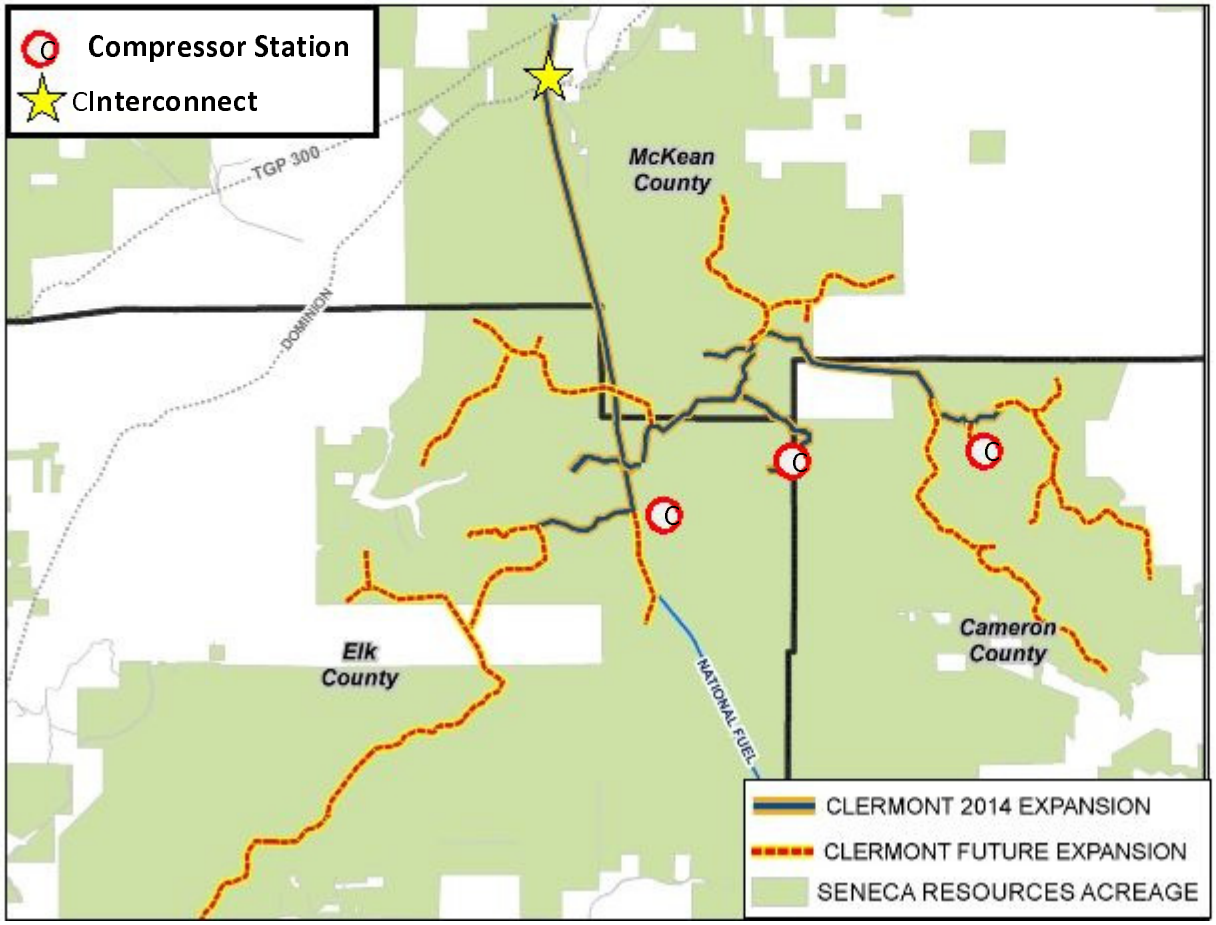
- In-Service Date: May 2012
- Capacity: 466,000 to 585,000 Dth per day
- Interconnect: Transco – Leidy Lateral
- Capital Expenditures (to date): $163 Million





(1) Fiscal 2015 estimated throughput reflects the midpoint of Seneca's Fiscal 2015 production guidance range (155-175 Bcfe).

Clermont Gathering System has Large Expandability

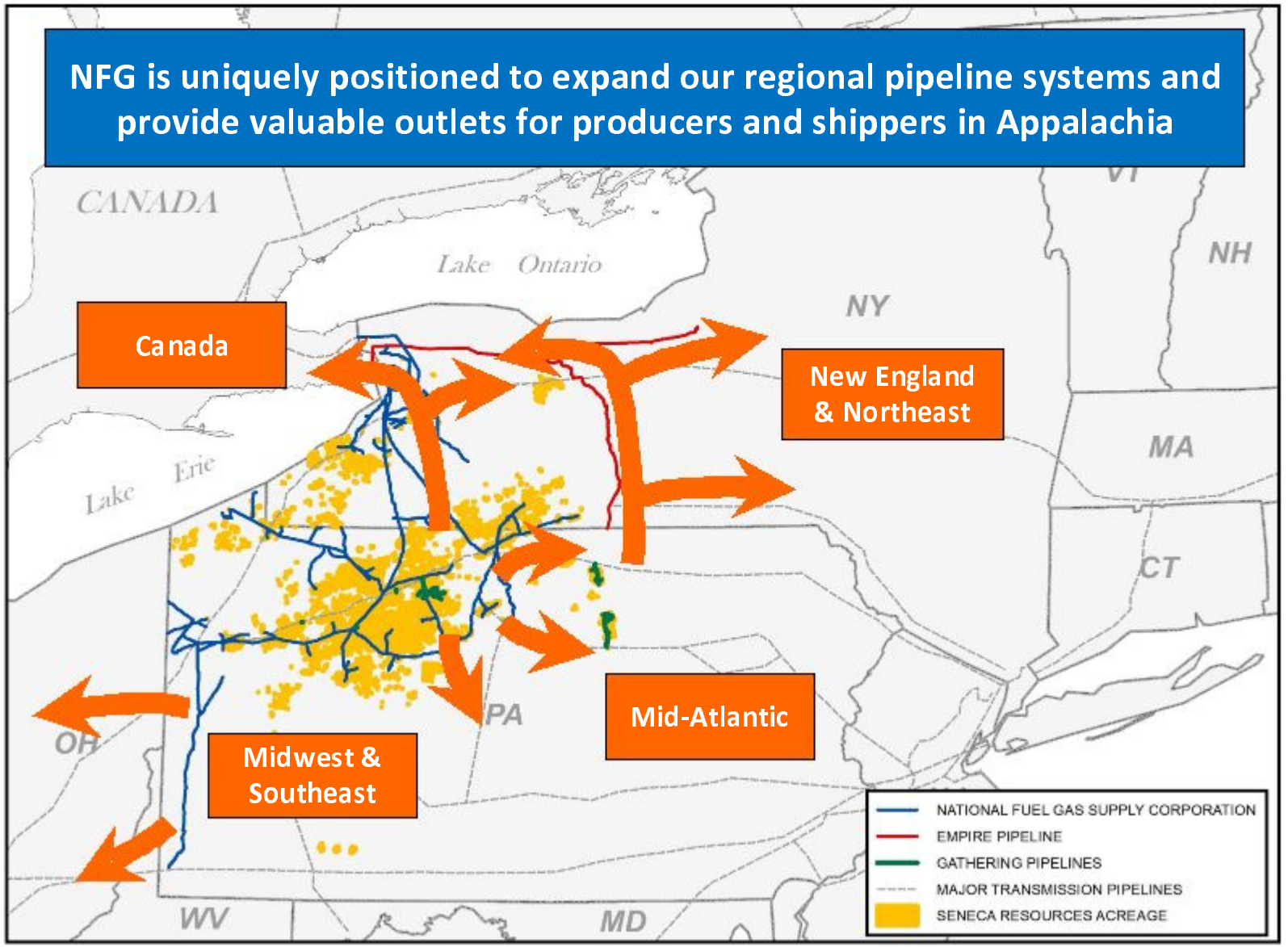


Clermont Gathering System

- In-Service: July 2014
- Ultimate Trunkline Capacity:
  - Approx. 1 Bcf per day
- Interconnects:
  - TGP 300 (current)
  - NFG Supply Corporation (Northern Access 2016)
- Capital Expenditures:
  - To date: $150 Million
  - 2015(1): $70 - $90 Million

(1) For the remaining six months of fiscal 2015.

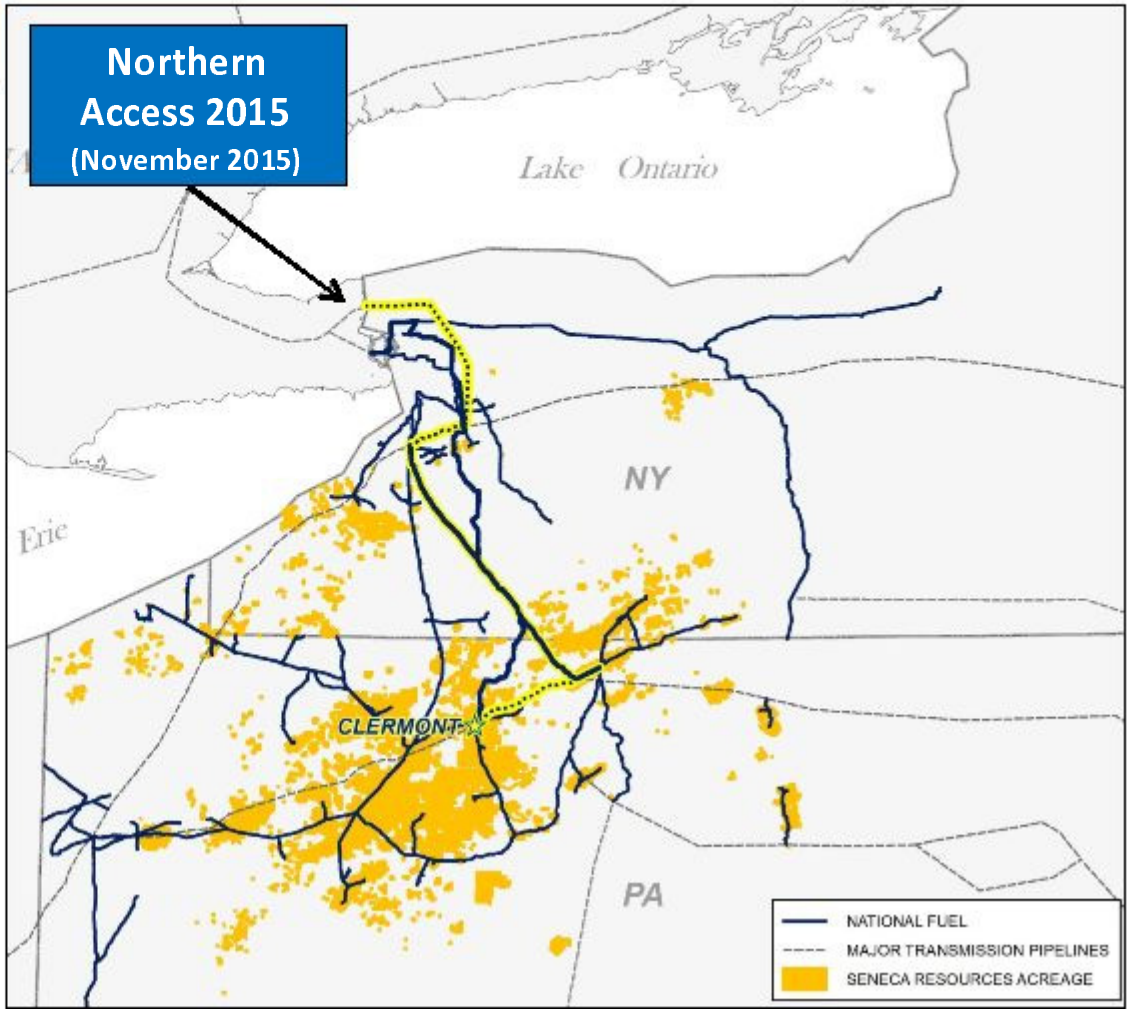
Pipeline & Storage: Premier Appalachian Position



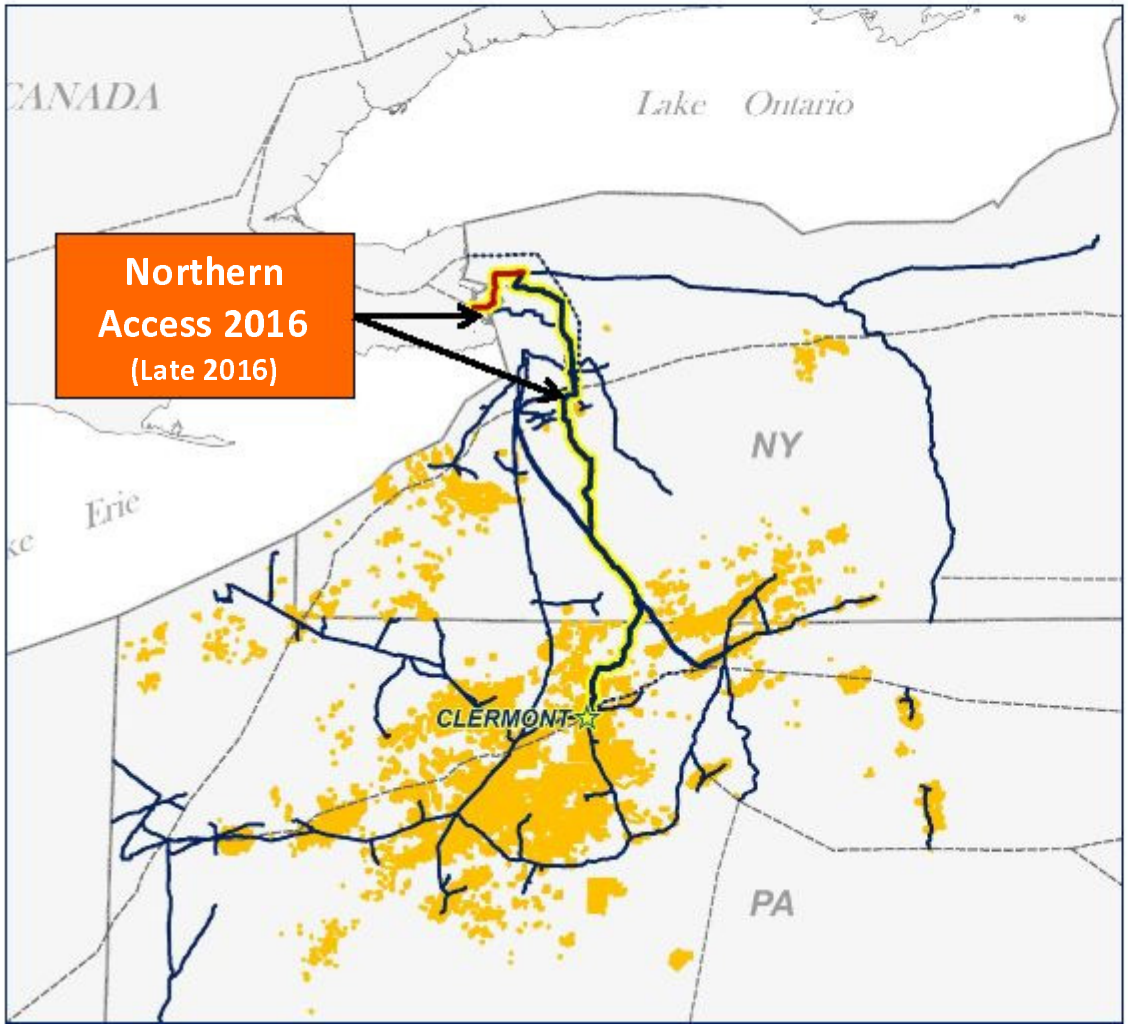
Major Expansion Designed for Canadian Deliveries

Northern Access 2015

- Customer: Seneca Resources
- In-Service: November 2015
- System: NFG Supply Corp.
- Capacity: 140,000 Dth per day
  - Lease to TGP as part of their Niagara Expansion project
- Interconnect
  - Niagara (TransCanada)
- Total Cost: $66 Million
- Major Facilities
  - 23,000 HP Compression
- FERC Status
  - Certificate received Feb. 2015



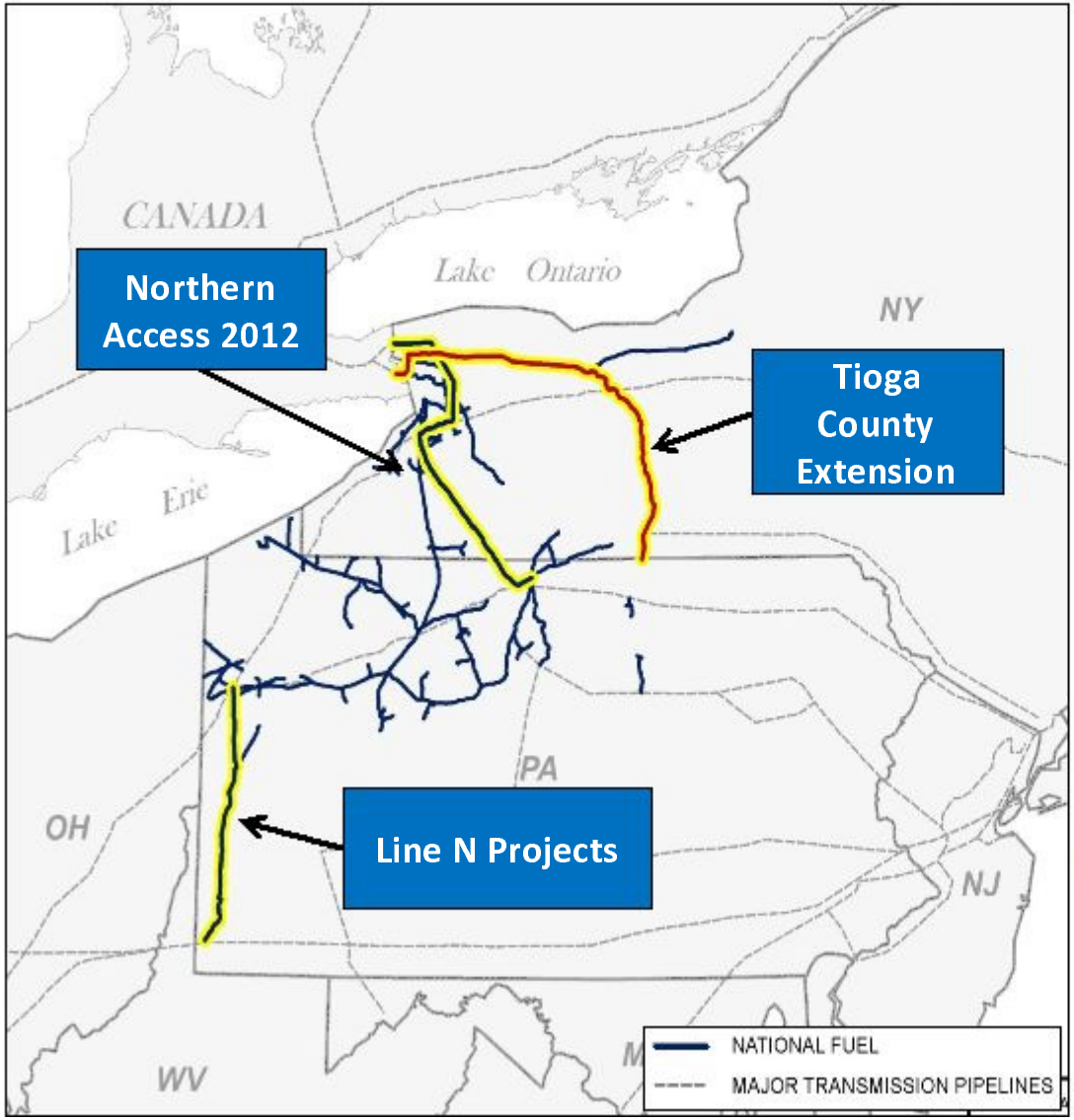
Northern Access 2016 Provides Access to Canada



Northern Access 2016

- Customer: Seneca Resources
- In-Service: Targeting Late 2016
- Capacity: 490,000 Dth/d
- Interconnects:
  - TransCanada – Chippawa (350,000 Dth/d)
  - TGP 200 – East Aurora (140,000 Dth/d)
- Total Cost: ~$451 Million
- FERC Status
  - Pre-filing: July 2014
  - Certificate filing: March 2015

Recent 3rd Party Expansions Highly Successful



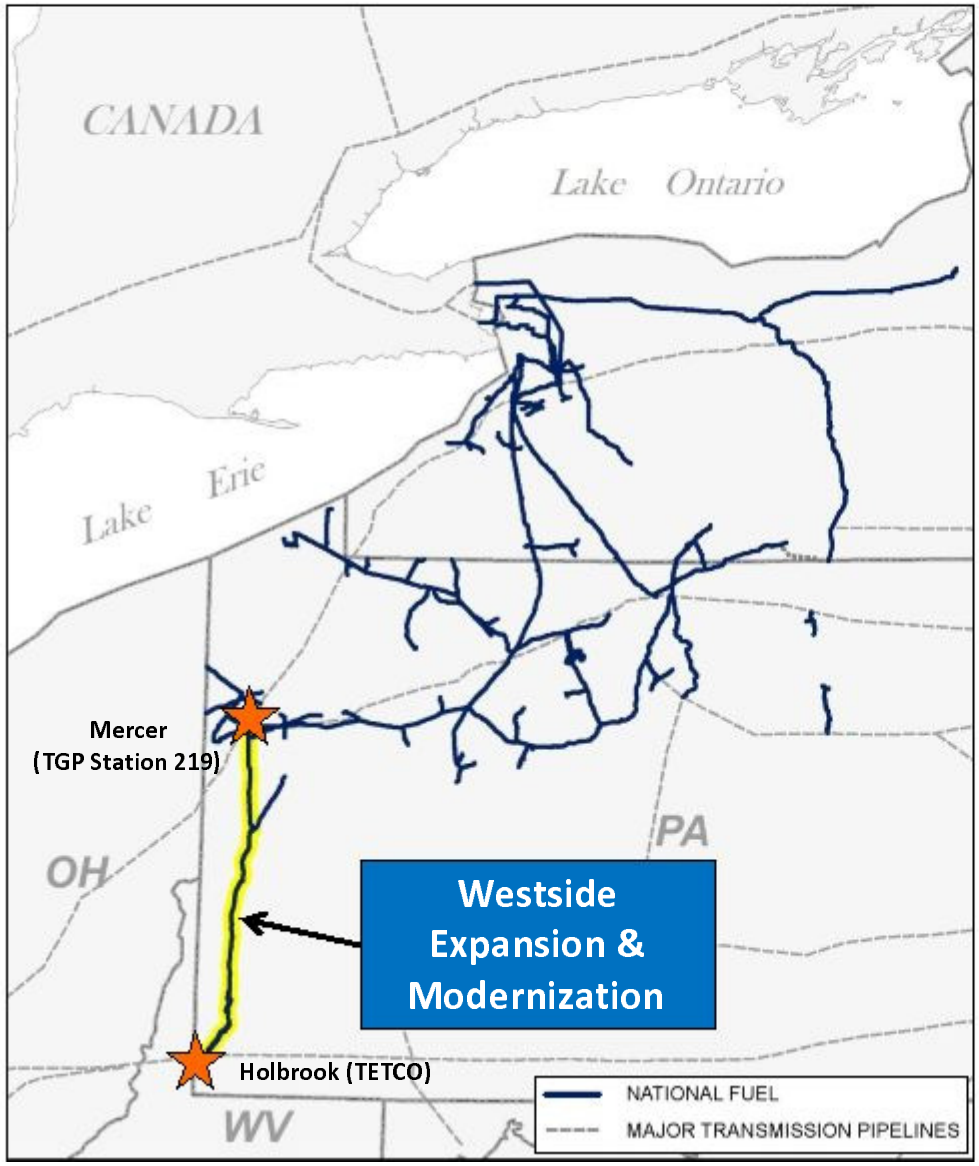
Completed Expansions

Capacity (Dth/day)	
Northern Access 2012	320,000
Tioga County Ext. & Lamont	440,000
Line N & Mercer Expansion	458,000
Total New Capacity	**1,218,000**

Capital Cost ($Millions)	
Northern Access 2012	$72
Tioga County Ext. & Lamont	$72
Line N & Mercer Expansion	$138
Total Capital Expenditures	**$282**

Annual Revenues ($Millions)	
Northern Access 2012	$16.1
Tioga County Ext. & Lamont	$33.4
Line N & Mercer Expansion	$23.1
Total Reservation Charges	**$72.6**

Pairing Line N Expansions with System Modernization



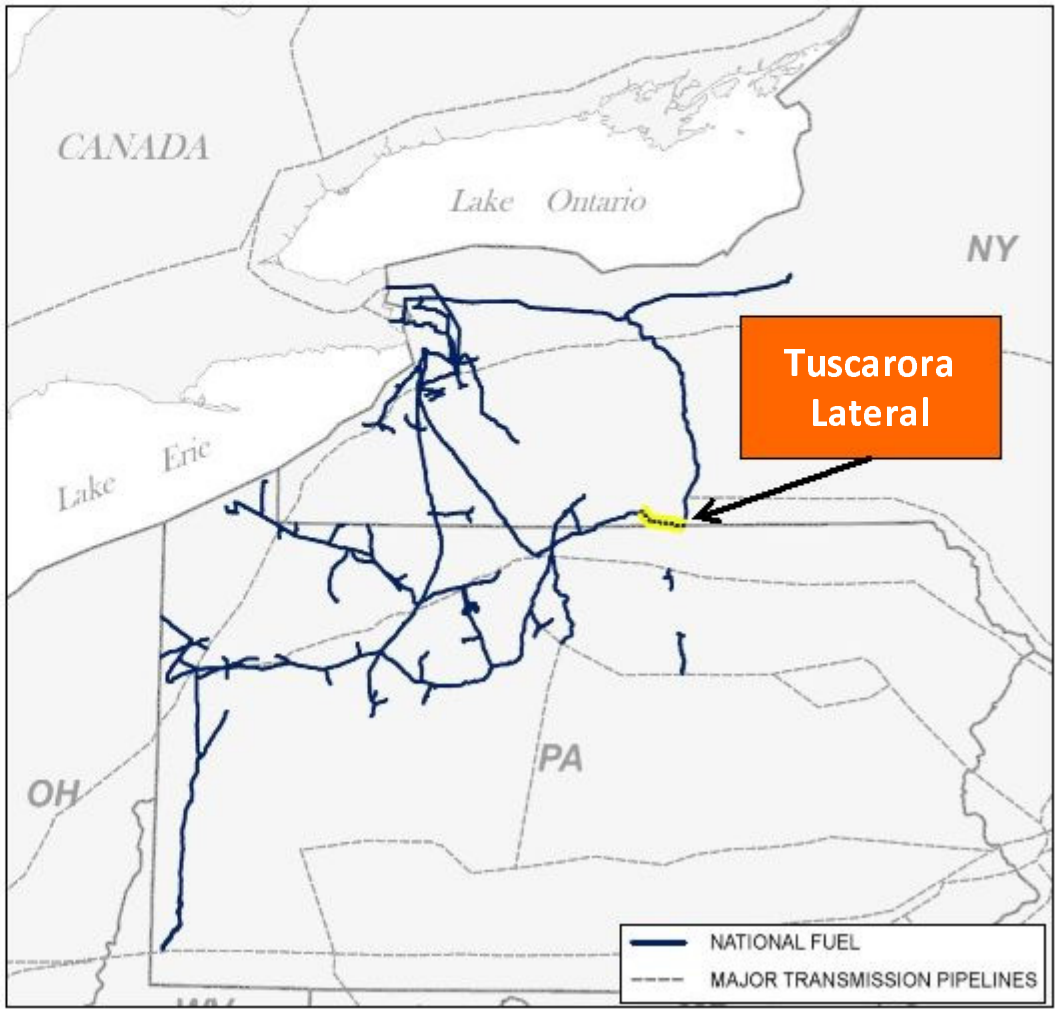
Westside Expansion & Modernization

- In-Service: November 2015
- System: NFG Supply Corp.
- Capacity: 175,000 Dth per day
  - Range Resources (145,000 Dth/d)
  - Seneca Resources (30,000 Dth/d)
- Interconnect
  - Mercer (TGP Station 219)
  - Holbrook (TETCO)
- Total Cost: $86 Million
  - Expansion: $45 Million
  - Modernization: $41 Million
- Major Facilities
  - 3,550 HP Compressor
  - 23.3 miles – 24” Replacement Pipe
- FERC Status
  - Certificate received March 2015

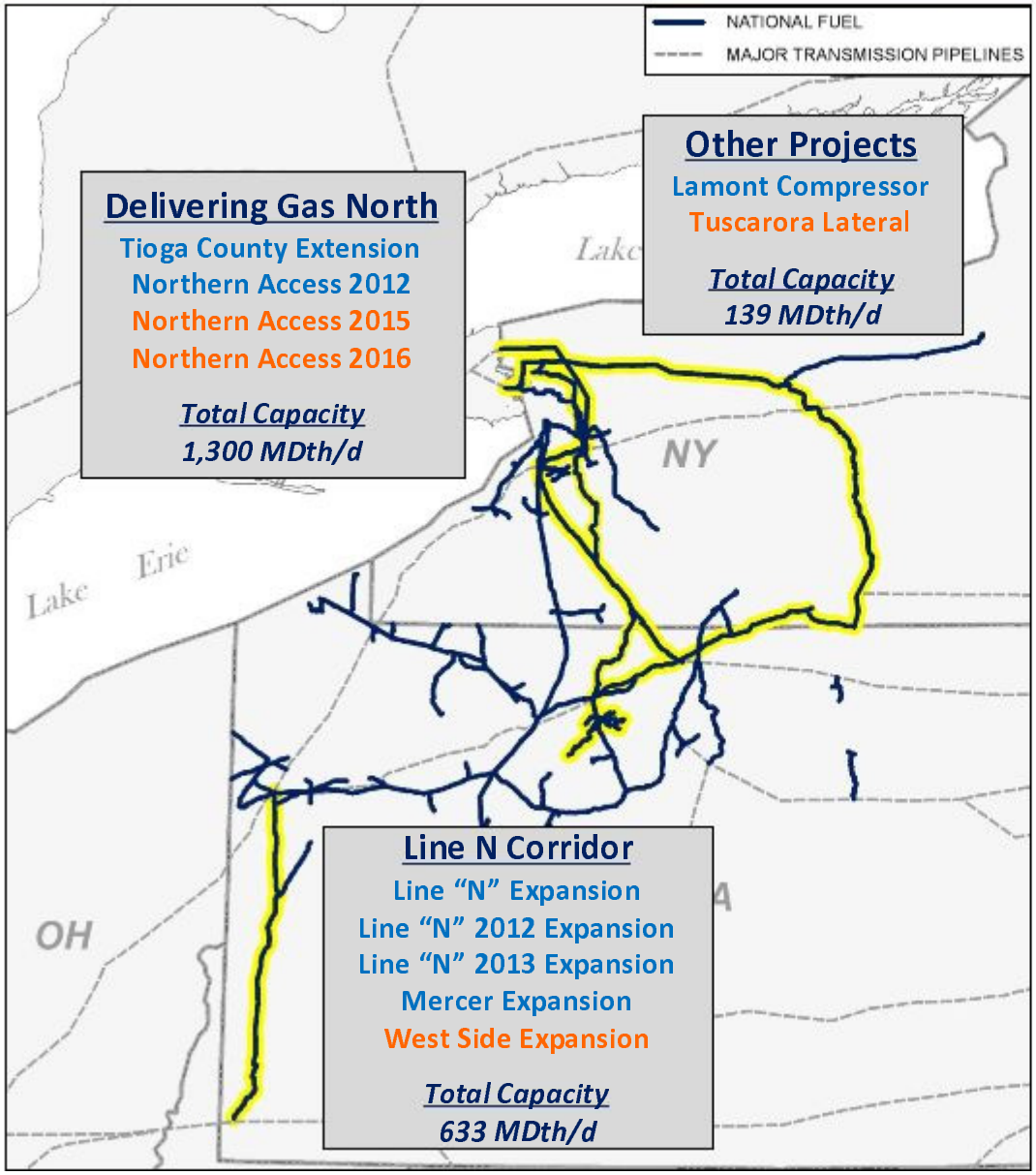
Developing Unique Solutions for Shippers

Tuscarora Lateral

- In-Service: November 2015
- System: NFG Supply & Empire Pipeline
- New No-Notice Services
  - Precedent agreements executed with RG&E, NYSEG & NFG Utility
  - Preserving 172,500 Dth per day (RG&E)
  - Preserving 20,000 Dth per day (NYSEG)
  - Retained Storage: 3.3 Bcf
  - New incremental transportation capacity of 49,000 Dth per day
- Interconnect
  - Tuscarora (NFG/Supply)
- Total Cost: $58.5 Million
- Major Facilities
  - 1,384 HP Compressor
  - 17 miles – 12”/16” Pipeline
- FERC Status
  - Certificate received March 2015



Significant Expansions Are Driving Growth



Completed Projects (Since 2009)	
Recent Capacity Additions	1,218,000 Dth/day

Planned Projects (2015+) *Precedent Agreements Executed*	
In-Service 2015	364,000 Dth/day
In-Service 2016+	490,000 Dth/day

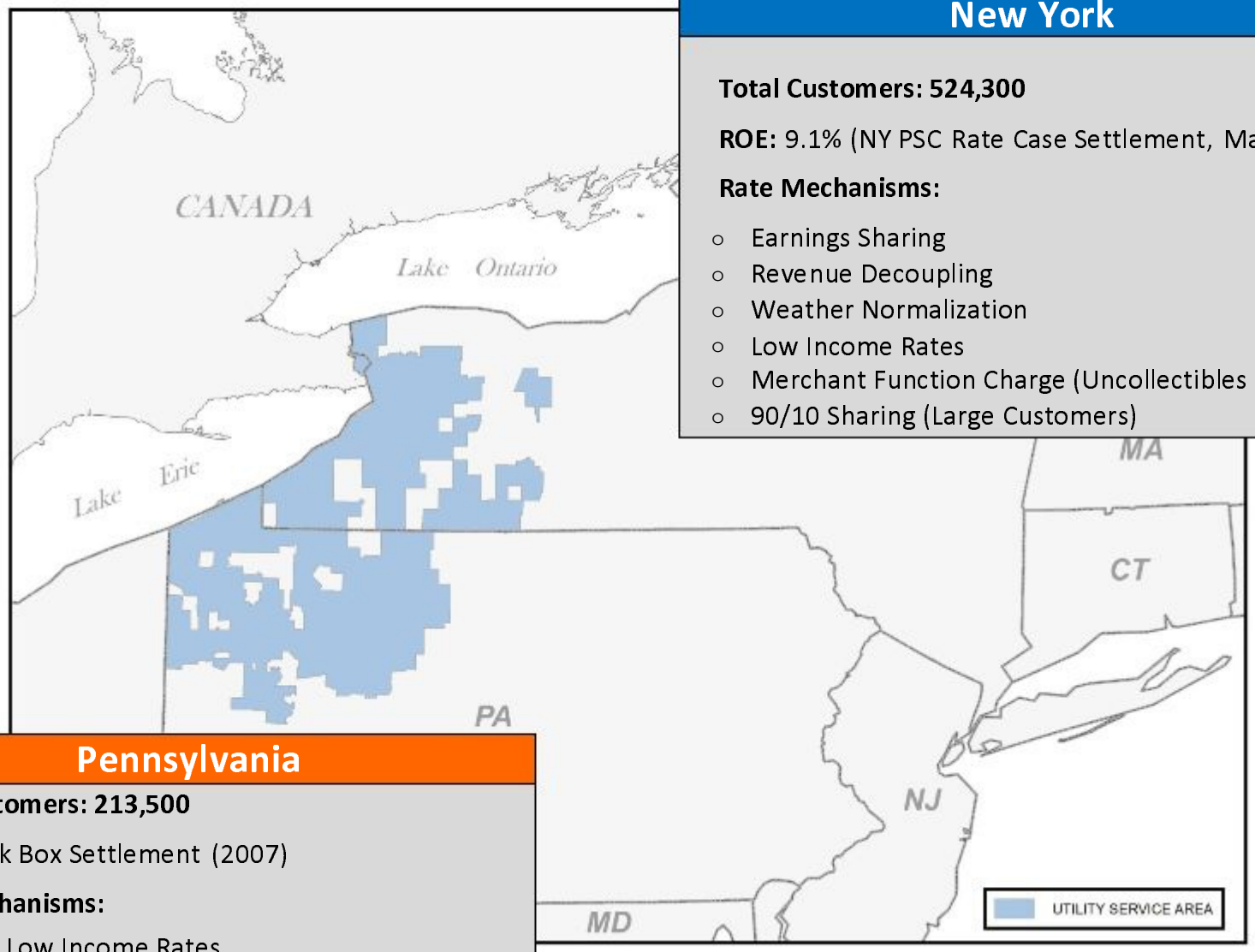
Total Expansion (2009-2016+)	
Capacity Additions	2,072,000 Dth/day

Downstream Overview

Utility

Energy Marketing

New York & Pennsylvania Service Territories



New York

Total Customers: 524,300

ROE: 9.1% (NY PSC Rate Case Settlement, May 2014)

Rate Mechanisms:

- Earnings Sharing
- Revenue Decoupling
- Weather Normalization
- Low Income Rates
- Merchant Function Charge (Uncollectibles Adj.)
- 90/10 Sharing (Large Customers)

Pennsylvania

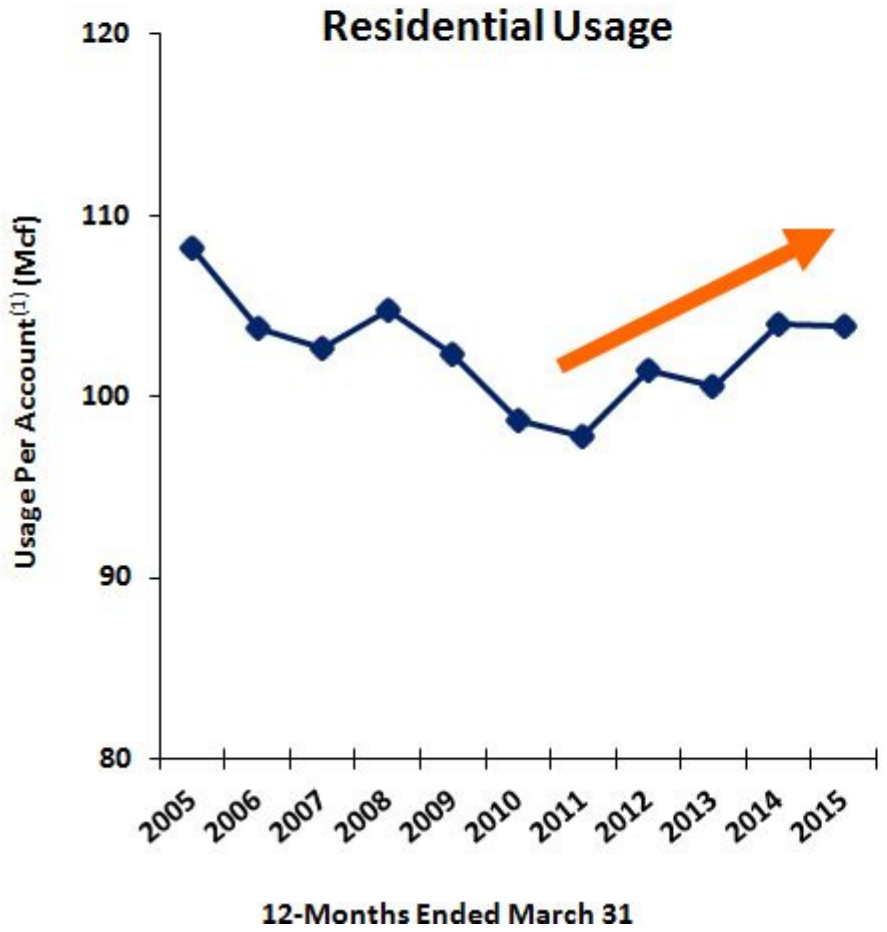
Total Customers: 213,500

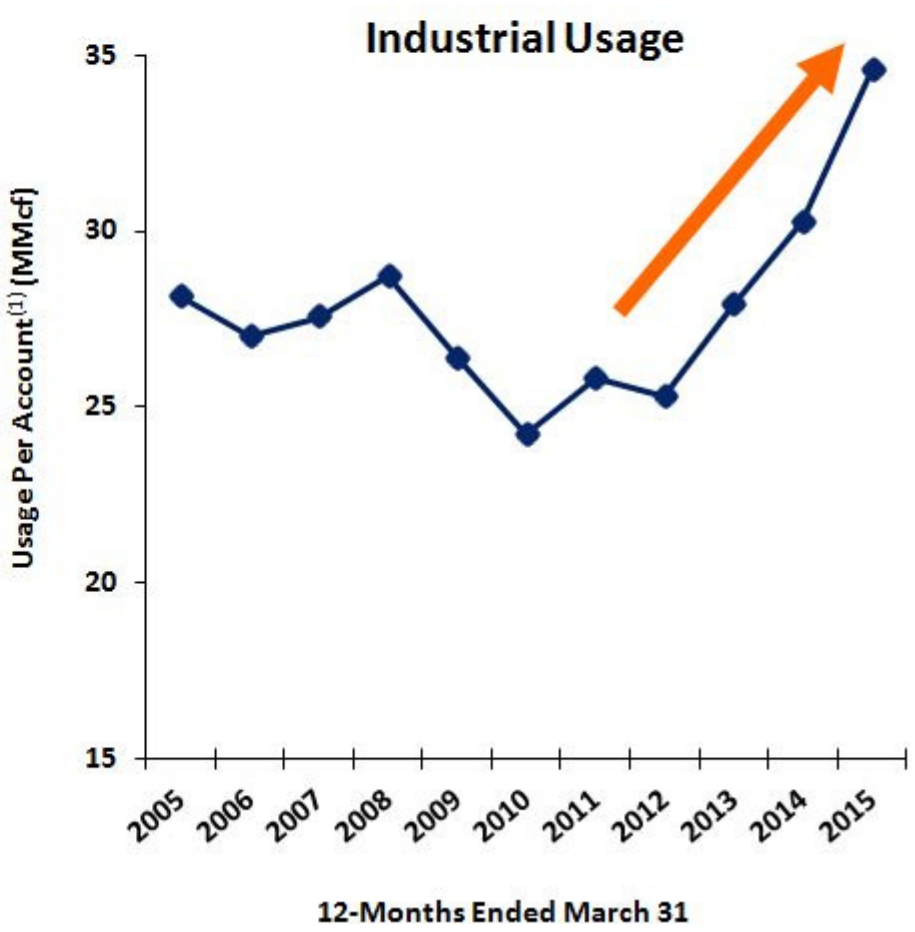
ROE: Black Box Settlement (2007)

Rate Mechanisms:

- Low Income Rates
- Merchant Function Charge

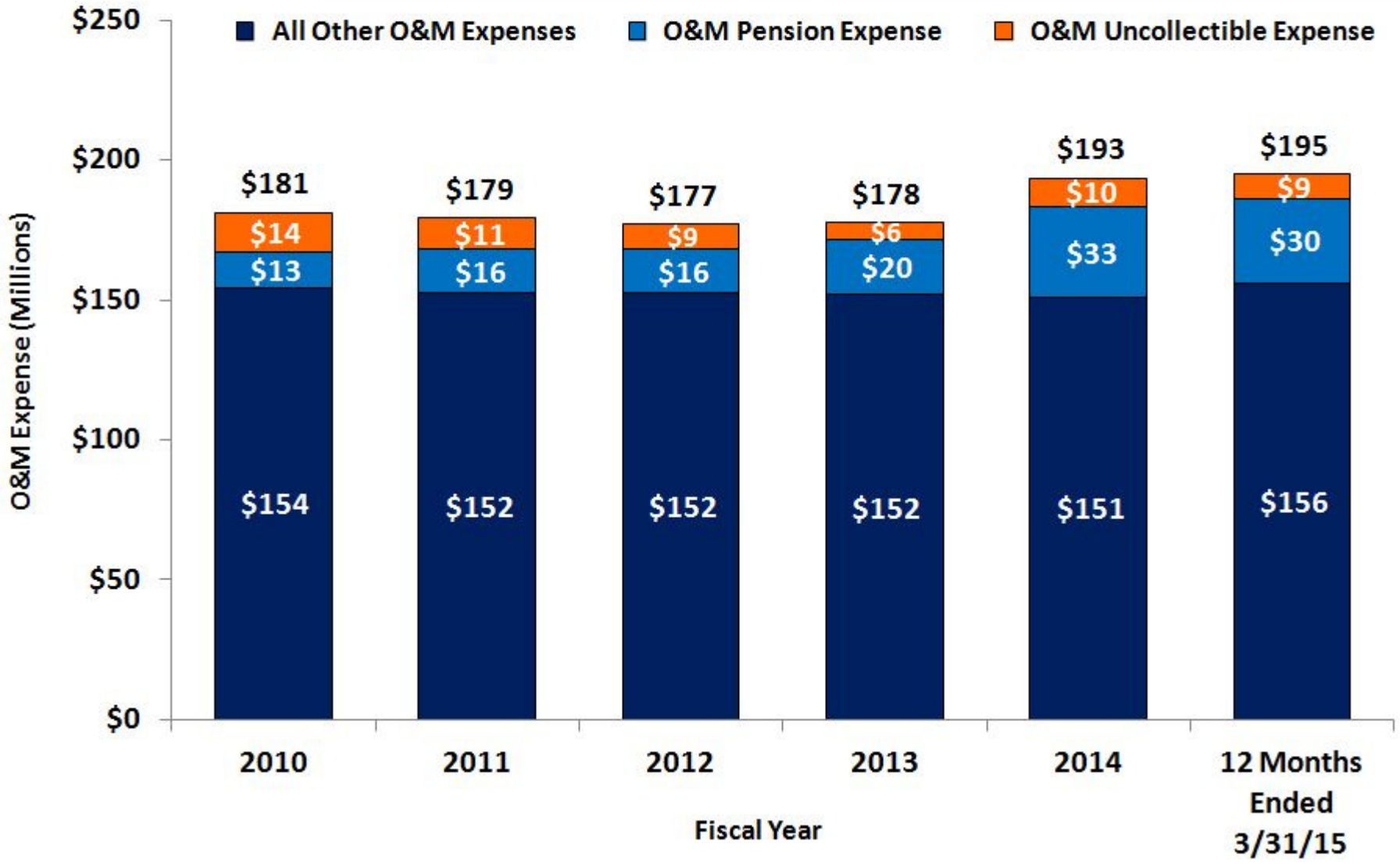
Utility: Shifting Trends in Customer Usage



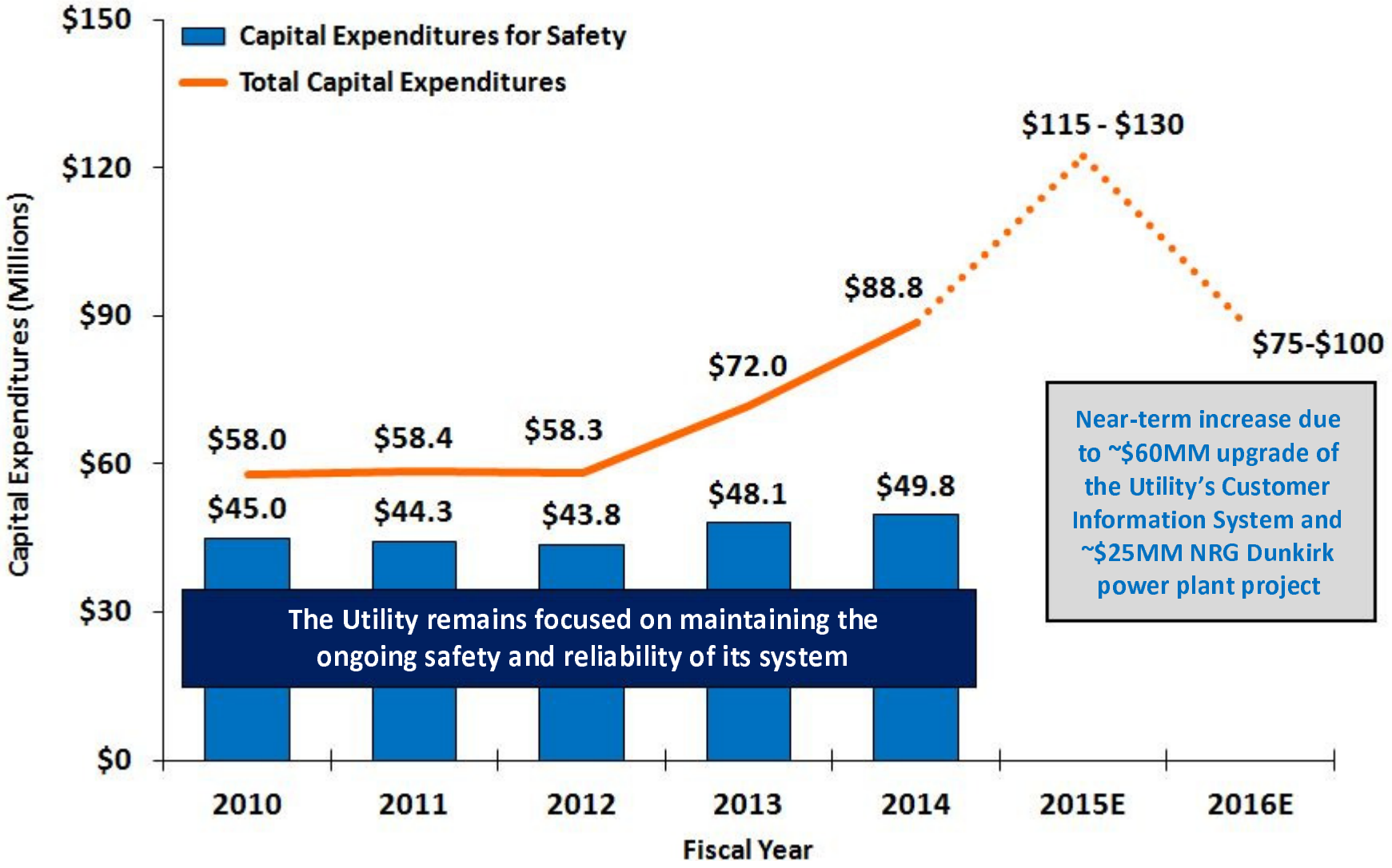


(1) Weighted Average of New York and Pennsylvania service territories (assumes normal weather).

A Proven History of Controlling Costs



Utility: Strong Commitment to Safety



Appendix

Natural Gas Hedge Positions

(Volumes in thousands Mmbtu; Prices in $/Mmbtu)

	Fiscal 2015[1]		Fiscal 2016		Fiscal 2017		Fiscal 2018	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
NYMEX Swaps	28,920	$ 4.18	32,350	$ 4.24	23,130	$ 4.50	5,550	$4.59
Dominion Swaps	12,420	$ 3.74	18,840	$3.78	12,720	$ 3.87	-	-
SoCal Swaps	600	$ 4.35	-	-	-	-	-	-
MichCon Swaps	-	-	9,000	$ 4.10	3,000	$ 4.10	-	-
Dawn Swaps	-	-	5,490	$ 4.36	7,950	$ 4.14	-	-
Fixed Price Physical Sales[2]	16,800	$ 3.42	36,600	$ 3.39	27,350	$ 3.51	1,550	$ 3.77
Total	**58,740**	**$ 3.87**	**102,280**	**$ 3.84**	**74,150**	**$ 3.97**	**7,100**	**$ 4.41**

(1) For the remaining six months of fiscal 2015.

(2) Includes new 50,000 Dth per day firm sales contract starting May 1, 2015 and ending on March 31, 2017 at $3.00 per Dth +/- NYMEX Henry Hub to Dawn differential. Differential assumed to be $0.00 per Dth for presentation purposes.

Crude Oil Hedge Positions

(Volumes & Prices in Bbl)

	Fiscal 2015[1]		Fiscal 2016		Fiscal 2017		Fiscal 2018	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
Midway Sunset (MWSS) Swaps	182,000	$68.62	36,000	$92.10	-	-	-	-
Brent Swaps	510,000	$98.32	933,000	$95.18	384,000	$92.30	75,000	$91.00
NYMEX Swaps	198,000	$90.14	300,000	$86.09	-	-	-	-
Total	**890,000**	**$90.43**	**1,269,000**	**$92.95**	**384,000**	**$92.30**	**75,000**	**$91.00**

(1) For the remaining six months of fiscal 2015.

WDA Delineation Well Results

Area	Producing Well Count	Peak 24-Hour Rate (MMcfd)	Average 7-Day (MMcf/d)	Average Treatable Lateral Length (ft)
Ridgway *Elk County*	1	7.1	6.4	5,537’
Church Run *Elk & Jefferson counties*	2	4.8	4.5	4,690’
Hemlock *Elk County*	2	5.4	5.2	7,067’
Owl’s Nest *Elk & Forest counties*	1	6.1	5.8	6,137’
Sulger Farms *Jefferson County*	1	6.1	5.6	5,778’

Comparable GAAP Financial Measure Slides & Reconciliations

This presentation contains certain non-GAAP financial measures. For pages that contain non-GAAP financial measures, pages containing the most directly comparable GAAP financial measures and reconciliations are provided in the slides that follow.

The Company believes that its non-GAAP financial measures are useful to investors because they provide an alternative method for assessing the Company's ongoing operating results, for measuring the Company's cash flow an d liquidity, and for comparing the Company's financial performance to other companies. The Company's management uses these non-GAAP financial measures for the same purpose, and for planning and forecasting purposes. The presentation of non-GAAP financial measures is not meant to be a substitute for financial measures prepared in accordance with GAAP.

The Company defines Adjusted EBITDA as reported GAAP earnings before the following items: interest expense, depreciation, depletion and amortization, interest and other income, impairments, items impacting comparability and income taxes.

National Fuel Gas Company

Appendix

Reconciliation of Adjusted EBITDA to Consolidated Net Income
($ Thousands)

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	12-Months Ended 3/31/15
Exploration & Production - West Division Adjusted EBITDA	$ 187,838	$ 187,603	$ 226,897	$ 215,042	$ 217,150	$ 177,646
Exploration & Production - All Other Divisions Adjusted EBITDA	139,624	189,854	170,232	277,341	322,322	325,397
Total Exploration & Production Adjusted EBITDA	$ 327,462	$ 377,457	$ 397,129	$ 492,383	$ 539,472	$ 503,043
Total Adjusted EBITDA						
Exploration & Production Adjusted EBITDA	$ 327,462	$ 377,457	$ 397,129	$ 492,383	$ 539,472	$ 503,043
Pipeline & Storage Adjusted EBITDA	120,858	111,474	136,914	161,226	186,022	190,439
Gathering Adjusted EBITDA	2,021	9,386	14,814	29,777	64,060	74,546
Utility Adjusted EBITDA	167,328	168,540	159,986	171,669	164,643	167,970
Energy Marketing Adjusted EBITDA	13,573	13,178	5,945	6,963	10,335	11,686
Corporate & All Other Adjusted EBITDA	408	(12,346)	(10,674)	(9,920)	(11,078)	(11,440)
Total Adjusted EBITDA	**$ 631,650**	**$ 667,689**	**$ 704,114**	**$ 852,098**	**$ 953,454**	**$ 936,244**
Total Adjusted EBITDA	**$ 631,650**	**$ 667,689**	**$ 704,114**	**$ 852,098**	**$ 953,454**	**$ 936,244**
Minus: Interest Expense	(93,946)	(78,121)	(86,220)	(94,111)	(94,277)	(93,364)
Plus: Interest and Other Income	9,855	8,863	8,842	9,032	13,631	11,202
Minus: Income Tax Expense	(137,227)	(164,381)	(150,554)	(172,758)	(189,614)	(128,390)
Minus: Depreciation, Depletion & Amortization	(191,199)	(226,527)	(271,530)	(326,760)	(383,781)	(386,125)
Minus: Impairment of Oil and Gas Properties (E&P)	-	-	-	-	-	(120,348)
Plus/Minus: Income/(Loss) from Discontinued Operations, Net of Tax (Corp. & All Other)	6,780	-	-	-	-	-
Plus: Gain on Sale of Unconsolidated Subsidiaries (Corp. & All Other)	-	50,879	-	-	-	-
Plus: Elimination of Other Post-Retirement Regulatory Liability (P&S)	-	-	21,672	-	-	-
Minus: Pennsylvania Impact Fee Related to Prior Fiscal Years (E&P)	-	-	(6,206)	-	-	-
Minus: New York Regulatory Adjustment (Utility)	-	-	-	(7,500)	-	-
Plus: Reversal of Plugging and Abandonment Accrual (E&P)					-	4,140
Rounding	-	-	(1)	-	-	-
Consolidated Net Income	**$ 225,913**	**$ 258,402**	**$ 220,117**	**$ 260,001**	**$ 299,413**	**$ 223,359**
Consolidated Debt to Total Adjusted EBITDA						
Long-Term Debt, Net of Current Portion (End of Period)	$ 1,049,000	$ 899,000	$ 1,149,000	$ 1,649,000	$ 1,649,000	$ 1,649,000
Current Portion of Long-Term Debt (End of Period)	200,000	150,000	250,000	-	-	-
Notes Payable to Banks and Commercial Paper (End of Period)	-	40,000	171,000	-	85,600	157,500
Total Debt (End of Period)	$ 1,249,000	$ 1,089,000	$ 1,570,000	$ 1,649,000	$ 1,734,600	$ 1,806,500
Long-Term Debt, Net of Current Portion (Start of Period)	1,249,000	1,049,000	899,000	1,149,000	1,649,000	1,649,000
Current Portion of Long-Term Debt (Start of Period)	-	200,000	150,000	250,000	-	-
Notes Payable to Banks and Commercial Paper (Start of Period)	-	-	40,000	171,000	-	-
Total Debt (Start of Period)	$ 1,249,000	$ 1,249,000	$ 1,089,000	$ 1,570,000	$ 1,649,000	$ 1,649,000
Average Total Debt	**$ 1,249,000**	**$ 1,169,000**	**$ 1,329,500**	**$ 1,609,500**	**$ 1,691,800**	**$ 1,727,750**
Average Total Debt to Total Adjusted EBITDA	**1.98 x**	**1.75 x**	**1.89 x**	**1.89 x**	**1.77 x**	**1.85 x**

National Fuel Gas Company

Reconciliation of Segment Capital Expenditures to Consolidated Capital Expenditures
($ Thousands)

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015 Forecast	FY 2016 Forecast
Capital Expenditures from Continuing Operations							
Exploration & Production Capital Expenditures	$ 398,174	$ 648,815	$ 693,810	$ 533,129	$ 602,705	$525,000-575,000	$400,000-475,000
Pipeline & Storage Capital Expenditures	37,894	129,206	144,167	$ 56,144	$ 139,821	$225,000-275,000	$500,000-550,000
Gathering Segment Capital Expenditures	6,538	17,021	80,012	$ 54,792	$ 137,799	$125,000-175,000	$100,000-125,000
Utility Capital Expenditures	57,973	58,398	58,284	$ 71,970	$ 88,810	$115,000-130,000	$75,000-100,000
Energy Marketing, Corporate & All Other Capital Expenditures	773	746	1,121	$ 1,062	$ 772	-	-
Total Capital Expenditures from Continuing Operations	$ 501,352	$ 854,186	$ 977,394	$ 717,097	$ 969,907	$990,000-1,155,000	$1,075,000-1,250,000
Capital Expenditures from Discountinued Operations							
All Other Capital Expenditures	$ 150	$ -	$ -	$ -	$ -	$ -	$ -
Plus (Minus) Accrued Capital Expenditures							
Exploration & Production FY 2014 Accrued Capital Expenditures	$ -	$ -	$ -	$ -	$ (80,108)		
Exploration & Production FY 2013 Accrued Capital Expenditures	-	-	-	(58,478)	58,478	-	-
Exploration & Production FY 2012 Accrued Capital Expenditures	-	-	(38,861)	38,861	-	-	-
Exploration & Production FY 2011 Accrued Capital Expenditures	-	(103,287)	103,287	-	-	-	-
Exploration & Production FY 2010 Accrued Capital Expenditures	(78,633)	78,633	-	-	-	-	-
Exploration & Production FY 2009 Accrued Capital Expenditures	19,517	-	-	-	-	-	-
Pipeline & Storage FY 2014 Accrued Capital Expenditures	-	-	-	-	(28,122)		
Pipeline & Storage FY 2013 Accrued Capital Expenditures	-	-	-	(5,633)	5,633	-	-
Pipeline & Storage FY 2012 Accrued Capital Expenditures	-	-	(12,699)	12,699	-	-	-
Pipeline & Storage FY 2011 Accrued Capital Expenditures	-	(16,431)	16,431	-	-	-	-
Pipeline & Storage FY 2010 Accrued Capital Expenditures	-	3,681	-	-	-	-	-
Pipeline & Storage FY 2008 Accrued Capital Expenditures	-	-	-	-	-	-	-
Gathering FY 2014 Accrued Capital Expenditures	-	-	-	-	(20,084)		
Gathering FY 2013 Accrued Capital Expenditures	-	-	-	(6,700)	6,700	-	-
Gathering FY 2012 Accrued Capital Expenditures	-	-	(12,690)	12,690	-	-	-
Gathering FY 2011 Accrued Capital Expenditures	-	(3,079)	3,079	-	-	-	-
Gathering FY 2009 Accrued Capital Expenditures	715	-	-	-	-	-	-
Utility FY 2014 Accrued Capital Expenditures	-	-	-	-	(8,315)		
Utility FY 2013 Accrued Capital Expenditures	-	-	-	(10,328)	10,328	-	-
Utility FY 2012 Accrued Capital Expenditures	-	-	(3,253)	3,253	-	-	-
Utility FY 2011 Accrued Capital Expenditures	-	(2,319)	2,319	-	-	-	-
Utility FY 2010 Accrued Capital Expenditures	-	2,894	-	-	-	-	-
Total Accrued Capital Expenditures	$ (58,401)	$ (39,908)	$ 57,613	$ (13,636)	$ (55,490)	$ -	$ -
Eliminations	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capital Expenditures per Statement of Cash Flows	$ 443,101	$ 814,278	$1,035,007	$ 703,461	$ 914,417	$990,000-1,155,000	$1,075,000-1,250,000