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 28, 2016

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 28, 2016, 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: impairments under the SEC's full cost ceiling test for natural gas and oil reserves; changes in the price of natural gas or oil; 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; 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; 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; 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; changes in demographic patterns and weather conditions; changes in the availability, price or accounting treatment of derivative financial instruments; 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 2016

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/ Paula M. Ciprich
Paula M. Ciprich
Secretary

Dated: April 28, 2016

EXHIBIT INDEX

Exhibit Number	Description
99	Investor Presentation dated April 2016

Exhibit 99

National Fuel®

Investor Presentation

Q2 Fiscal 2016 Update

April 2016

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: Impairments under the SEC's full cost ceiling test for natural gas and oil reserves; changes in the price of natural gas or oil; 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; 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; 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; 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 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; changes in demographic patterns and weather conditions; changes in the availability, price or accounting treatment of derivative financial instruments; 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, 2015 and the Forms 10-Q for the quarters ended December 31, 2015 and March 31, 2016. 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.

National Fuel Gas Company

Quality Assets | Exceptional Location | Unique Integration

Upstream

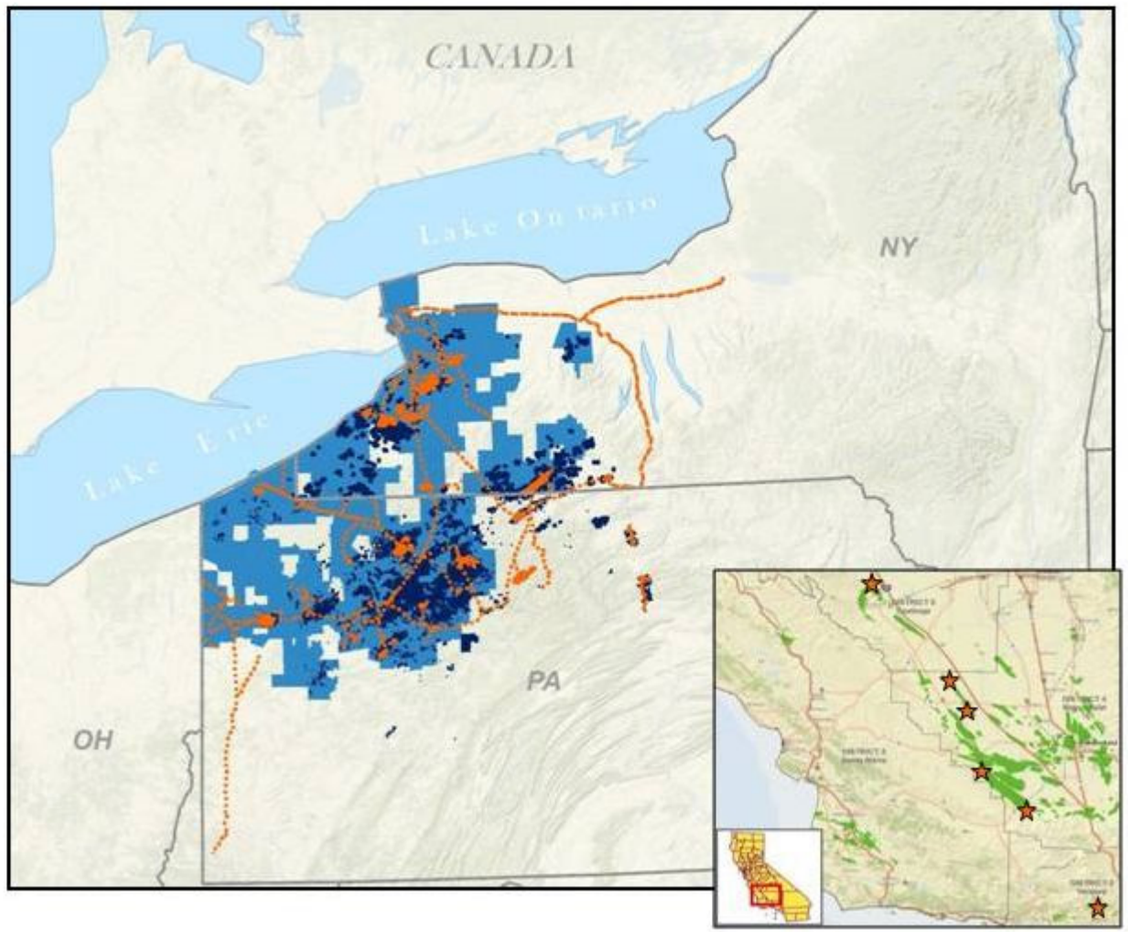
- 2.3 Tcfe Proved Reserves (1)
- 785,000 net acres in Marcellus Shale
- 3 million Bbls/year California crude oil production

Midstream

- $255 million adjusted EBITDA (2)
- $1.2 billion midstream investments since 2010
- Coordinated infrastructure build-out in Appalachia with NFG Upstream

Downstream

- 740,000 Utility customer accounts
- Stable, regulated earnings & cash flows
- Generates operational and financial synergies with other segments



(1) Total proved reserves are as of September 30, 2015.

(2) For the trailing twelve months ended March 31, 2016. 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.

Integrated Vision for Long-term Growth in Appalachia

Exploration & Production

1

Long-term, return-driven approach to developing vast acreage position

Gathering

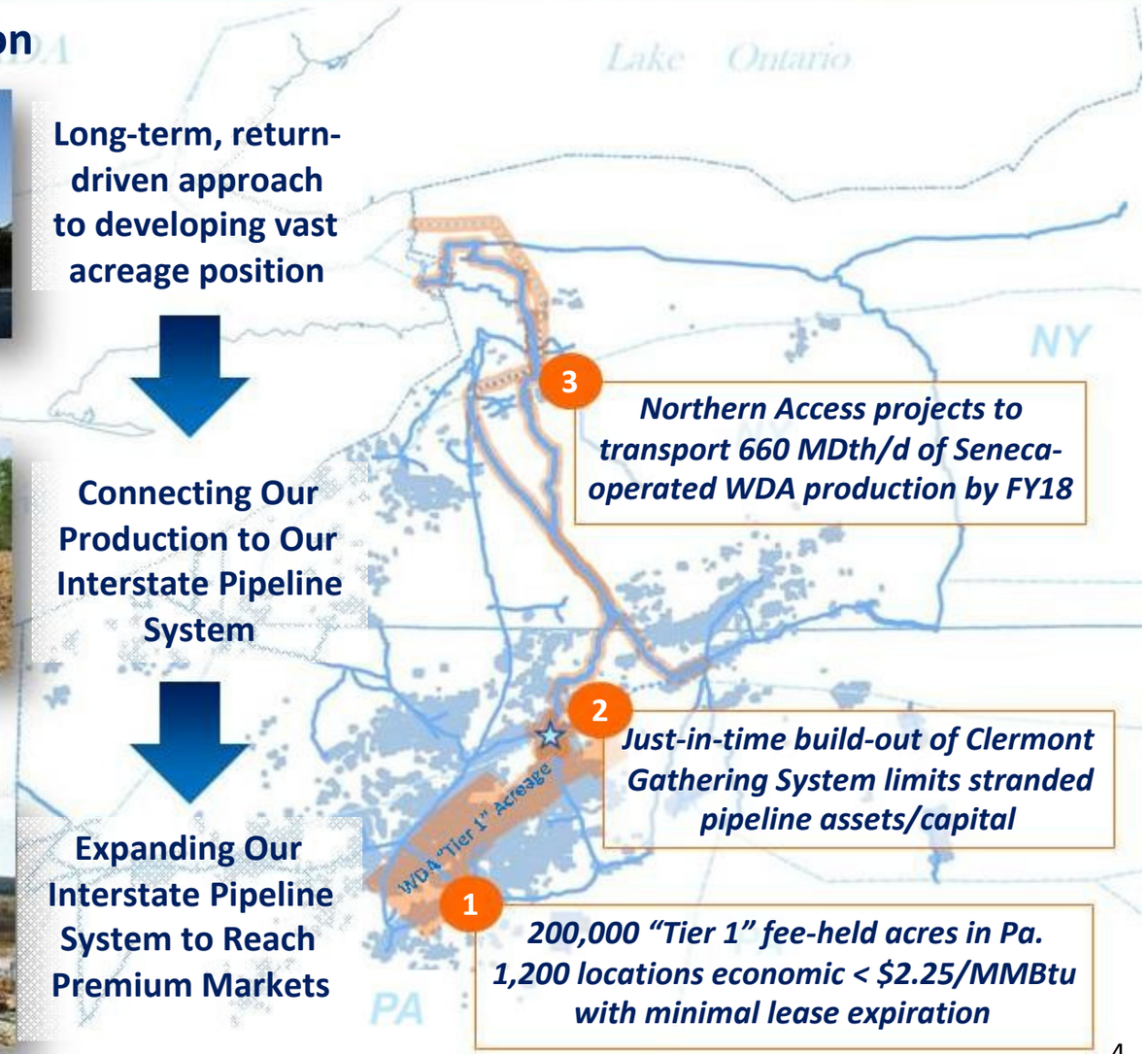
2

Connecting Our Production to Our Interstate Pipeline System

Pipeline & Storage

3

Expanding Our Interstate Pipeline System to Reach Premium Markets



3 ***Northern Access projects to transport 660 MDth/d of Seneca-operated WDA production by FY18***

2 ***Just-in-time build-out of Clermont Gathering System limits stranded pipeline assets/capital***

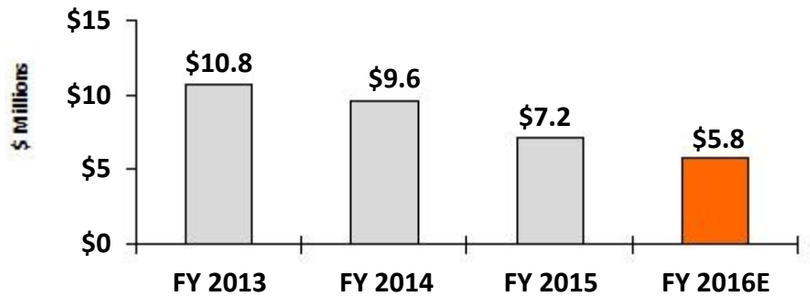
1 ***200,000 "Tier 1" fee-held acres in Pa. 1,200 locations economic < $2.25/MMBtu with minimal lease expiration***

Integrated Upstream & Midstream Development

While Seneca has consistently driven down its well costs and improved break-even economics …

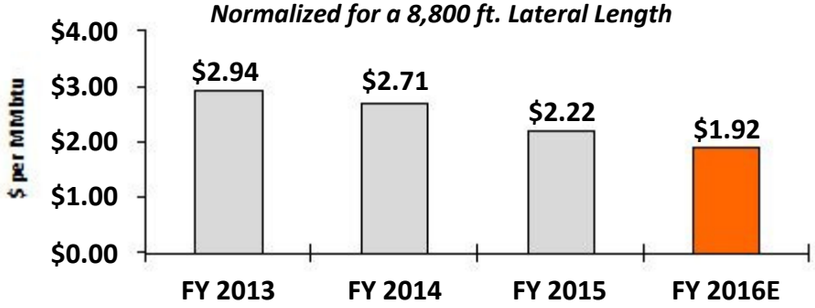
WDA Well Costs ($millions)

Normalized for a 8,800 ft. Lateral Length



WDA Clermont / Rich Valley Economics

Realized Price Required for 15% IRR (1)
Normalized for a 8,800 ft. Lateral Length



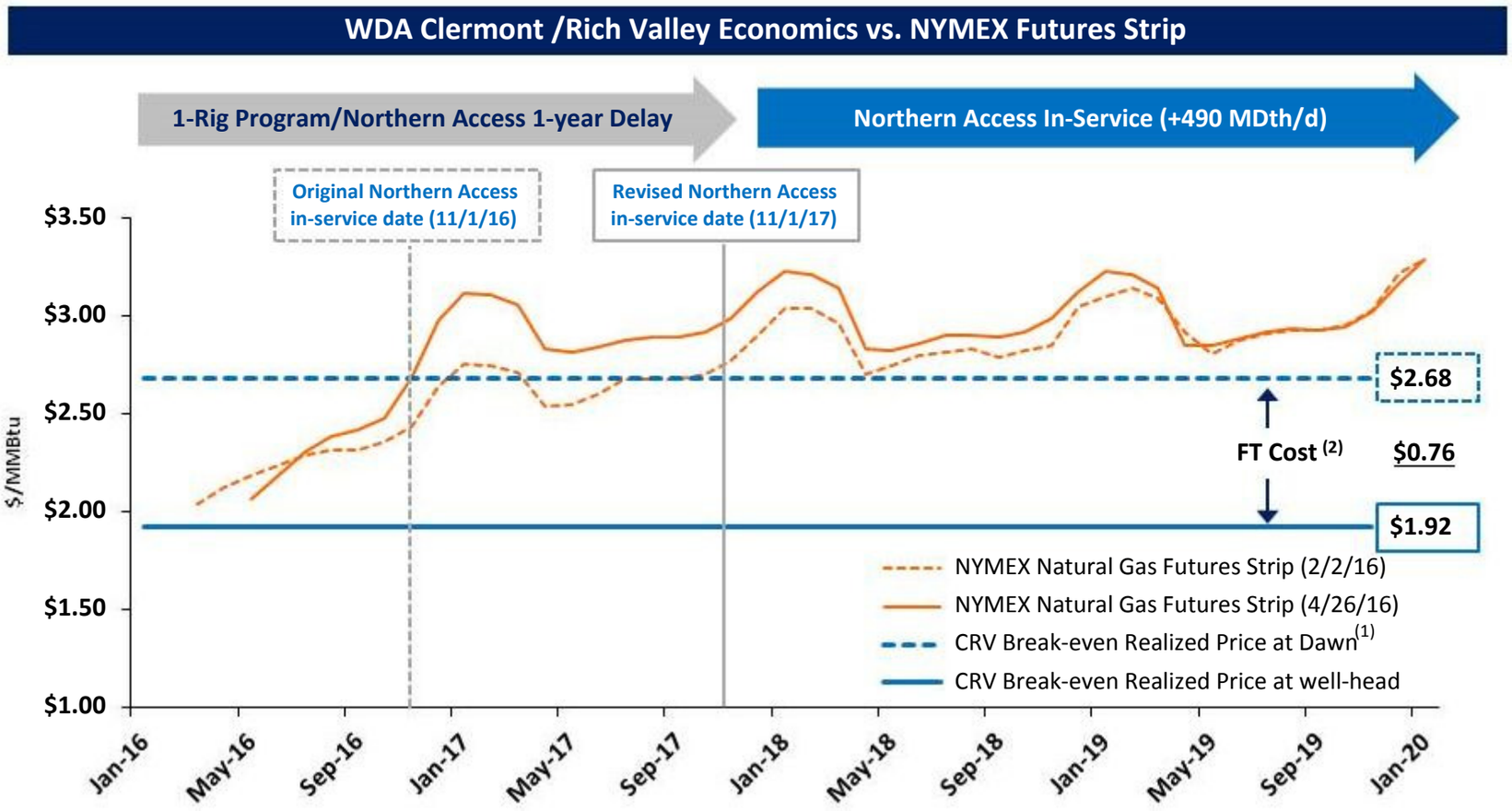
Marcellus Drilling Cost per Foot

Marcellus Completion Cost per Stage ($000s)

(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. Assumes Dawn is on par with NYMEX.

Integrated Upstream & Midstream Development

… near-term commodity prices prompted modification to upstream & midstream development pace

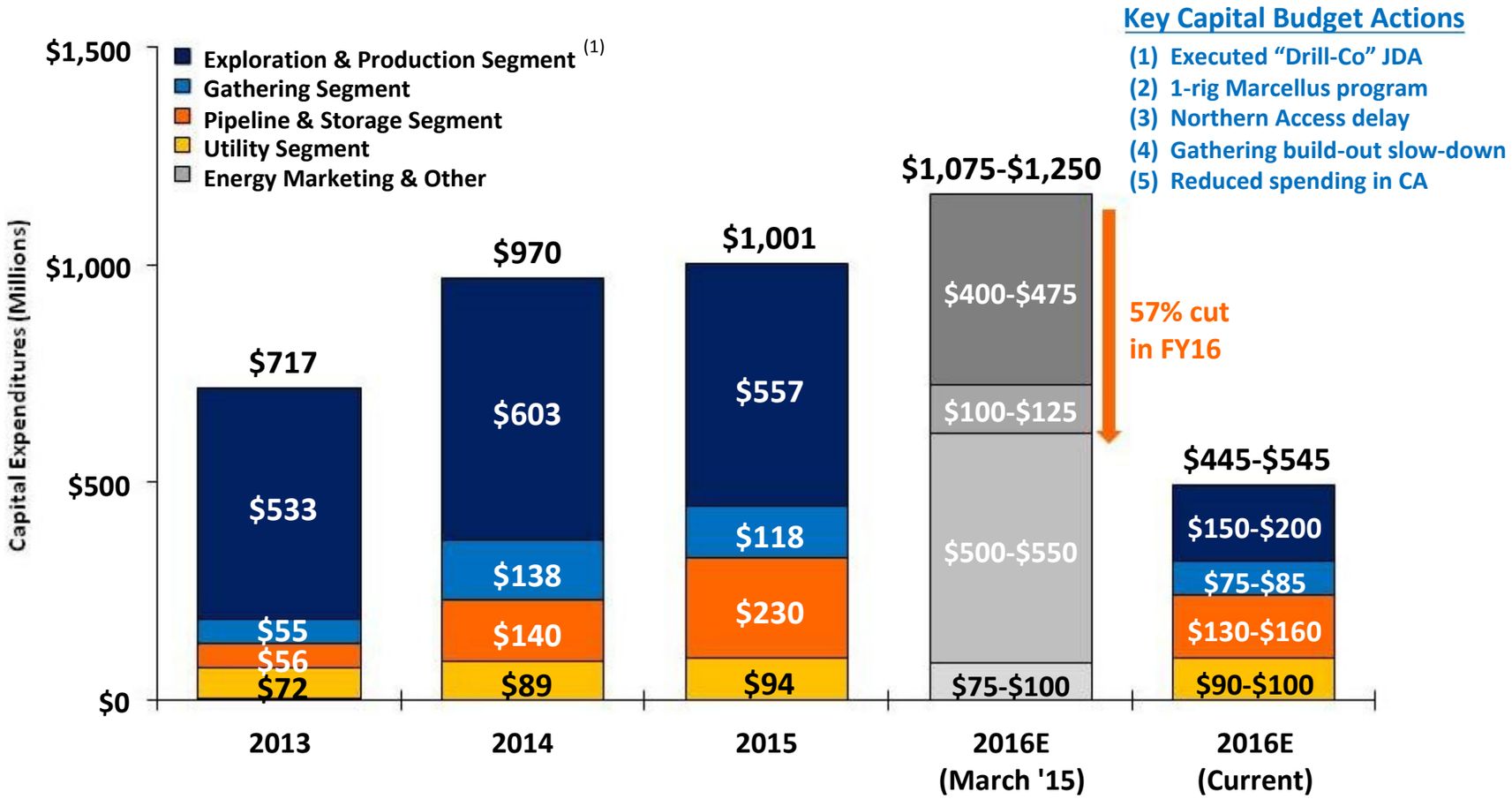


(1) Internal Rate of Return (IRR) is pre-tax and includes estimated well costs under current cost structure, LOE and gathering tariffs anticipated for each prospect. Assumes Dawn is on par with NYMEX.

(2) Reflects $0.70 per Dth reservation charge, including the cost of non-affiliated downstream transportation from the Canadian border to Dawn, and assumes approximately $0.06 per Dth of variable fees (commodity, fuel, etc.).

Consolidated Capital Expenditures

Exercising Capital Flexibility and Discipline to Respond to Commodity Price Environment



Key Capital Budget Actions

(1) Executed "Drill-Co" JDA
(2) 1-rig Marcellus program
(3) Northern Access delay
(4) Gathering build-out slow-down
(5) Reduced spending in CA

(1) FY2016 capital expenditure guidance reflects the netting of up-front proceeds received from joint development partner for capital spent on wells drilled and/or completed prior to the execution date of the joint development agreement. The E&P segment's FY16 & FY17 capital budgets would be reduced by an additional $90-$110 million if joint development partner exercises right to participate in remaining 38 wells.

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

National Fuel is Well Positioned

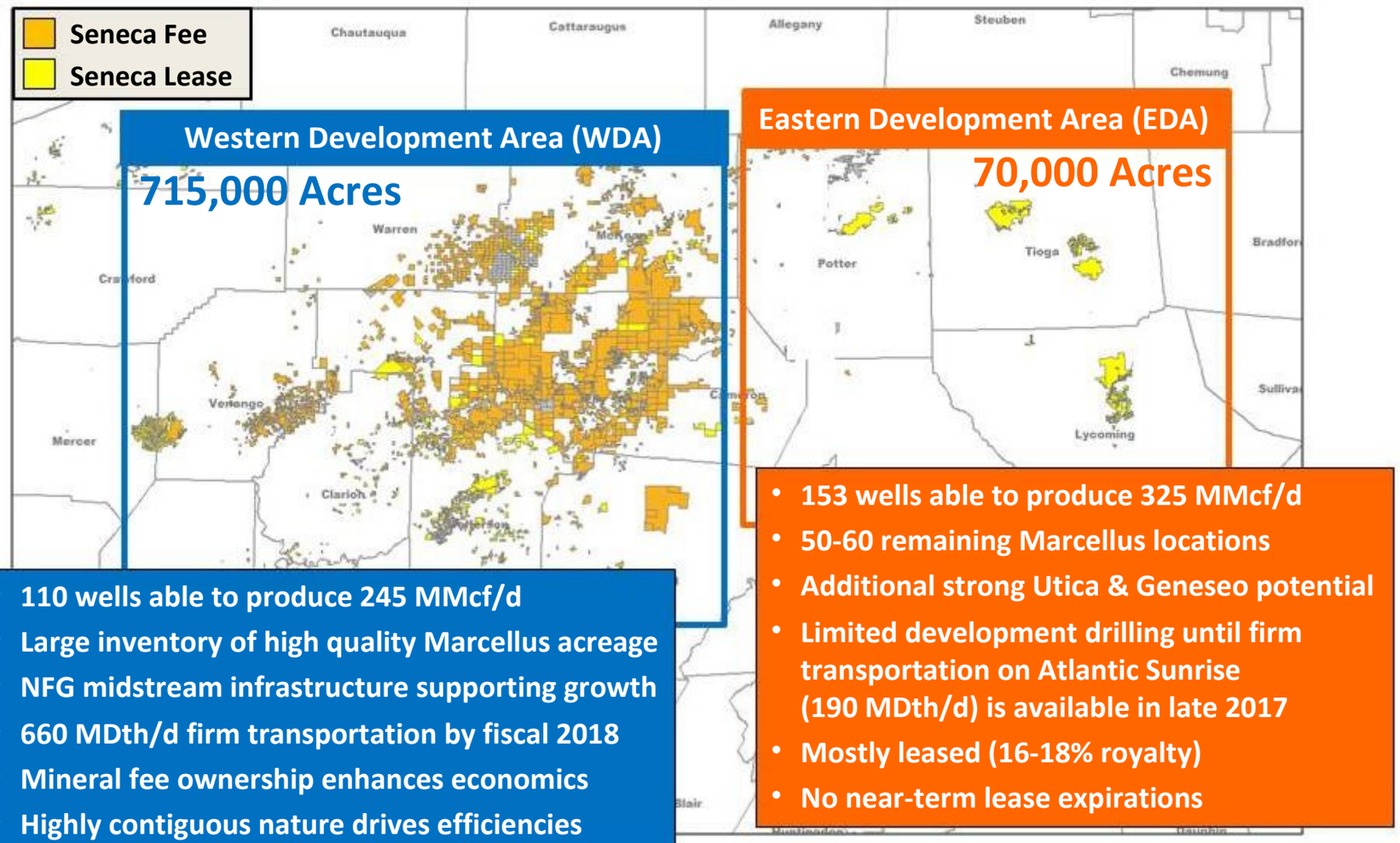
Flexibility to Deploy Capital	✓ Fee ownership on Marcellus acreage limits drilling commitments (& royalties) ✓ Just-in-time midstream development model for upstream affiliate limits risk of idle capital and minimizes contractual commitments to 3rd party pipelines ✓ Modest 1-rig program, curtailed volumes and DUC well inventory allow for a steady ramp-up of productive capacity to fill Northern Access by end of FY 2018
Strong Balance Sheet and Liquidity	✓ Investment grade credit rating ✓ $1.25 billion short-term credit facilities can accommodate modest outspend in FY 2017 ✓ No near-term debt maturities to refinance
Strong Hedge Book and Firm Sales Portfolio	✓ Robust hedge book in FY 2016 & FY 2017 at attractive prices ✓ FY2016 hedges: 80% and 55% of remaining natural gas & crude oil production ✓ Allows E&P segment to live within cash flows in FY16 and FY17 at current strips ✓ Preserves near-term well economics and protects affiliated midstream throughput
Stable, Growing Base of Regulated Earnings & Cash Flows	✓ Utility segment provides stable, predictable earnings and cash flows ✓ Pipeline & Storage EBITDA growth from 2015 projects and on-going expansions ✓ Supports investment grade rating ✓ Covers commitment to dividend, debt service and maintenance expenditures

Appalachia Overview

Exploration & Production | Gathering | Pipeline & Storage

Significant Appalachian Acreage Position

Exploration & Production — Appalachia



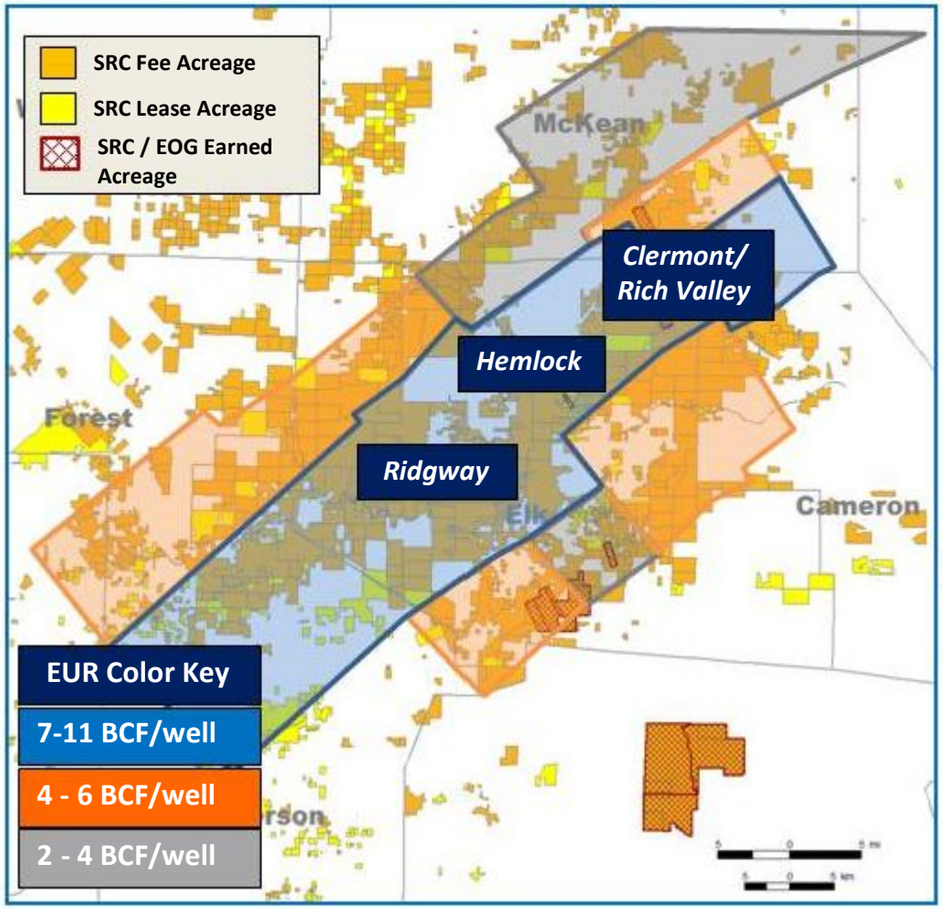
- 110 wells able to produce 245 MMcf/d
- Large inventory of high quality Marcellus acreage
- NFG midstream infrastructure supporting growth
- 660 MDth/d firm transportation by fiscal 2018
- Mineral fee ownership enhances economics
- Highly contiguous nature drives efficiencies

- 153 wells able to produce 325 MMcf/d
- 50-60 remaining Marcellus locations
- Additional strong Utica & Geneseo potential
- Limited development drilling until firm transportation on Atlantic Sunrise (190 MDth/d) is available in late 2017
- Mostly leased (16-18% royalty)
- No near-term lease expirations

Marcellus Shale: Western Development Area

Exploration & Production — Appalachia

WDA Tier 1 Acreage – 200,000 Acres



WDA Highlights

- ✓ **Large drilling inventory of quality Marcellus dry gas**
  - ~1,100 locations economic < $2.25/MMBtu realized
- ✓ **NFG midstream infrastructure supporting growth**
  - NFG Clermont Gathering System
  - 660 MDth/d firm transport on NFG projects by FY18
- ✓ **Fee acreage provides flexibility/enhances economics**
  - No royalty on most acreage
  - No lease expirations or requirements to drill acreage
- ✓ **Highly contiguous position drives D&C efficiencies**
  - Multi-well pad drilling averaging 10 wells per pad
  - Average lateral length to date = 7,800 ft.
  - Centralized water sourcing & disposal infrastructure
- ✓ **2 Utica tests expected in fiscal 2016/2017**

WDA Tier 1 Marcellus Economics(1)

	Locations Remaining	Avg EUR (Bcf)	$3.00 NYMEX/Dawn IRR%	15% IRR Realized Price
CRV	60	10-11	23%	$1.92
Hemlock/Ridgway	636	8-9	16%	$2.14
Other Tier 1	406	7-8	14%	$2.21

(1) Internal rate of return (IRR) is pre-tax and includes estimated well costs under the current well design and cost structure and projected firm transportation, gathering, LOE and other operating costs. CRV and Hemlock/Ridgway well designs assume 8,800 ft. lateral and 190 ft. frac stage spacing. Other Tier 1 well designs assume 8,500 ft. lateral and 190 ft. frac stage spacing.

Seneca WDA Joint Development Agreement

Exploration & Production — **Appalachia**

Transaction

On December 2, 2015, Seneca entered into an asset-level joint development agreement with IOG CRV-Marcellus Capital, LLC, an affiliate of IOG Capital, LP, and funds managed by affiliates of Fortress Investment Group, LLC, to jointly develop Marcellus Shale natural gas assets located in Elk, McKean and Cameron counties in north-central PA.

Key Terms

- **Assets:** 80 current and future Marcellus development wells in the Clermont/Rich Valley region of Seneca's WDA.
- **Partner's Initial Obligation**: 42 wells
- **Partner Option:** Partner has one-time option to participate in remaining 38 wells on or before July 1, 2016.
- **Economics:** Partner participates as an 80% working interest owner until the Partner achieves a 15% IRR hurdle. Seneca retains a 7.5% royalty and remaining 20% working interest.

Interests on Initial 42 Wells	Seneca	Partner
Working Interest	20%	80%
Net Revenue Interest	26%	74%

- **Marketing:** Partner to receive same realized price before hedging as Seneca on production from the joint development wells, including firm sales and the cost of firm transportation.

Strategic Rationale

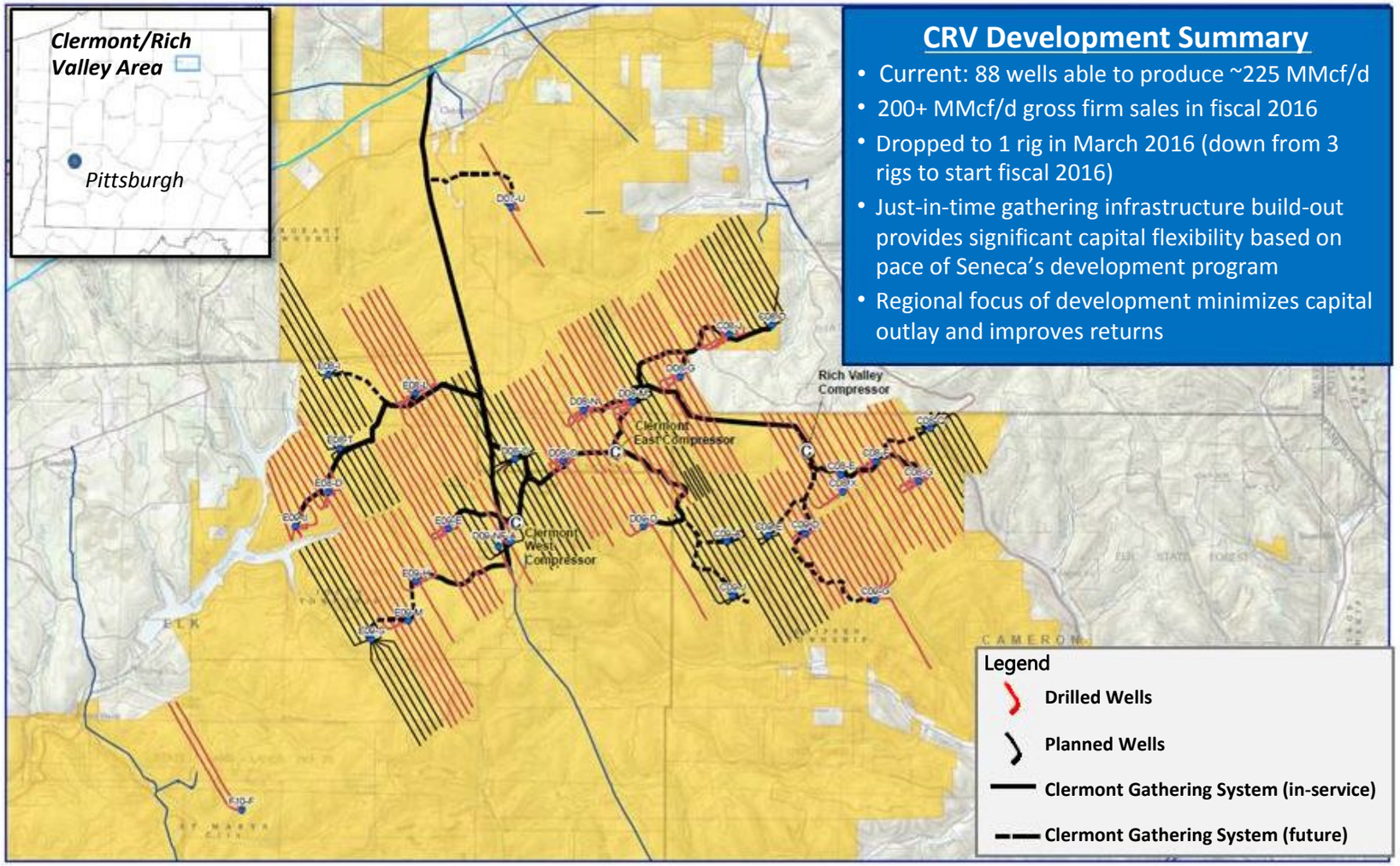
- ✓ Significantly reduced near-term upstream capital spending
  - ***Initial 42 wells*** - $200 million (1)
  - ***38 well option*** - $180 million (1)
- ✓ Validated quality of Seneca's Tier 1 Marcellus WDA acreage
- ✓ Seneca maintained activity levels driving additional Marcellus drilling and completion efficiencies
- ✓ Solidified NFG's midstream growth strategy:
  - ***Gathering*** - All production from JV wells will flow through NFG Midstream's Clermont Gathering System
  - ***Pipeline & Storage*** - Provides production growth that will utilize the 660 MDth/d of firm transportation capacity on NFG's Northern Access pipeline expansion projects
- ✓ Strengthened balance sheet and makes Seneca cash flow positive in near-term

(1) Estimated reduction in capital expenditures from joint development agreement assumes current wells costs.

Integrated WDA Development -Upstream

Exploration & Production — **Appalachia**

Clermont/Rich Valley Development Map



CRV Development Summary

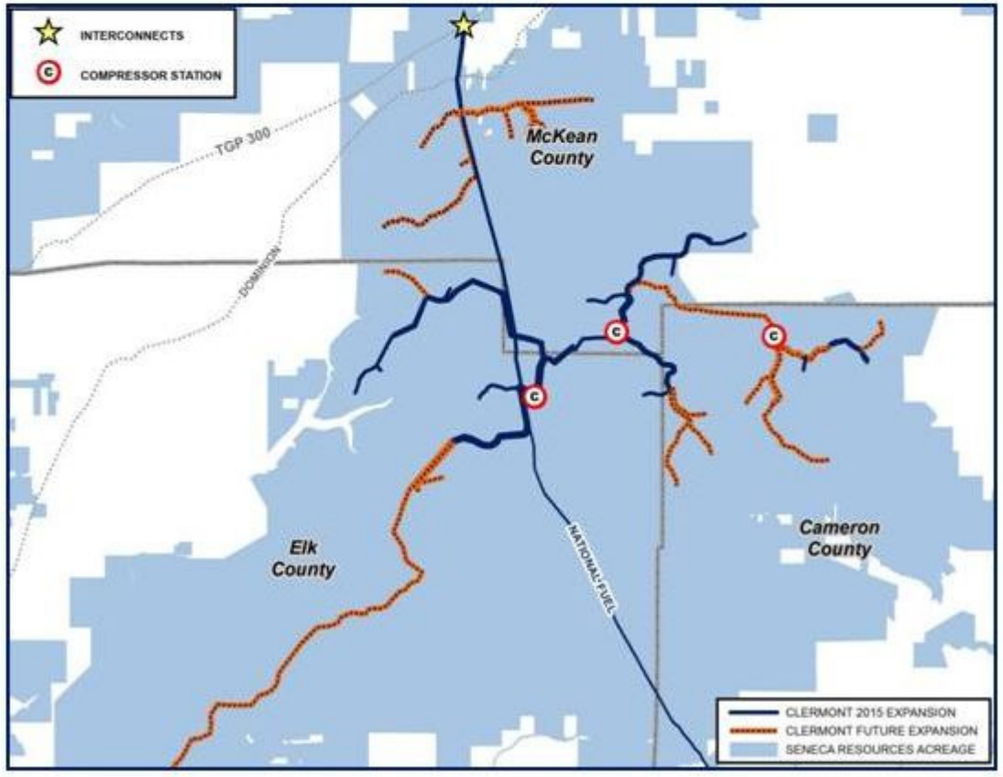
- Current: 88 wells able to produce ~225 MMcf/d
- 200+ MMcf/d gross firm sales in fiscal 2016
- Dropped to 1 rig in March 2016 (down from 3 rigs to start fiscal 2016)
- Just-in-time gathering infrastructure build-out provides significant capital flexibility based on pace of Seneca's development program
- Regional focus of development minimizes capital outlay and improves returns

Integrated WDA Development -Gathering

Gathering | Appalachia

Gathering System Build-Out Tailored to Accommodate Seneca's WDA Development

Clermont Gathering System Map



Current System In-Service

- ~60 miles of pipe/13,800 HP of compression
- Current Capacity: 470 MMcf per day
- Interconnects with TGP 300
- Total CapEx To Date: $247 million

Fiscal 2016 Build Out

- FY16 CapEx(1): $30 to $40 million
- Adjusted timing of gathering & compression investment to match Seneca's modified development schedule/Northern Access
- Will exit FY16 with > 72 miles of pipe installed and >26,220 HP commissioned

Future Build-Out (FY17+)

- Ultimate capacity can exceed 1 Bcf/d
- Over 300 miles of pipelines and five compressor stations (+60,000 HP installed)
- Deliverability into TGP 300 and NFG Supply

(1) For the remaining six months of fiscal 2016.

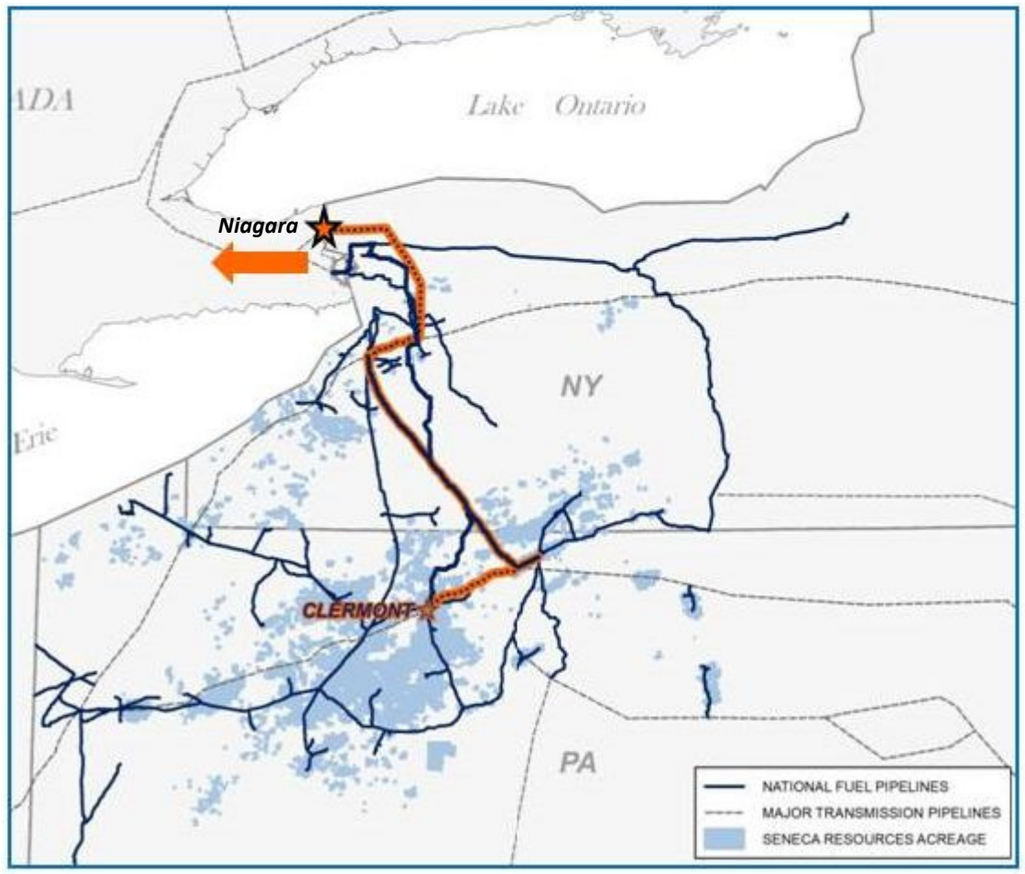
Integrated WDA Development - Interstate Pipelines

Pipeline & Storage | Appalachia

Expanding Our Interstate Pipelines to Deliver Seneca's WDA Production to Canada

Northern Access 2015

- Customer: Seneca Resources (NFG)
- In-Service: November 2015(1)
- System: NFG Supply Corp.
- Capacity: 140,000 Dth per day
  - Leased to TGP as part of TGP's Niagara Expansion project
- Delivery Interconnect:
  - Niagara (TransCanada)
- Major Facilities:
  - 23,000 hp Compression
- Total Cost: $67.5 million
- Annual Revenues: $13.3 million

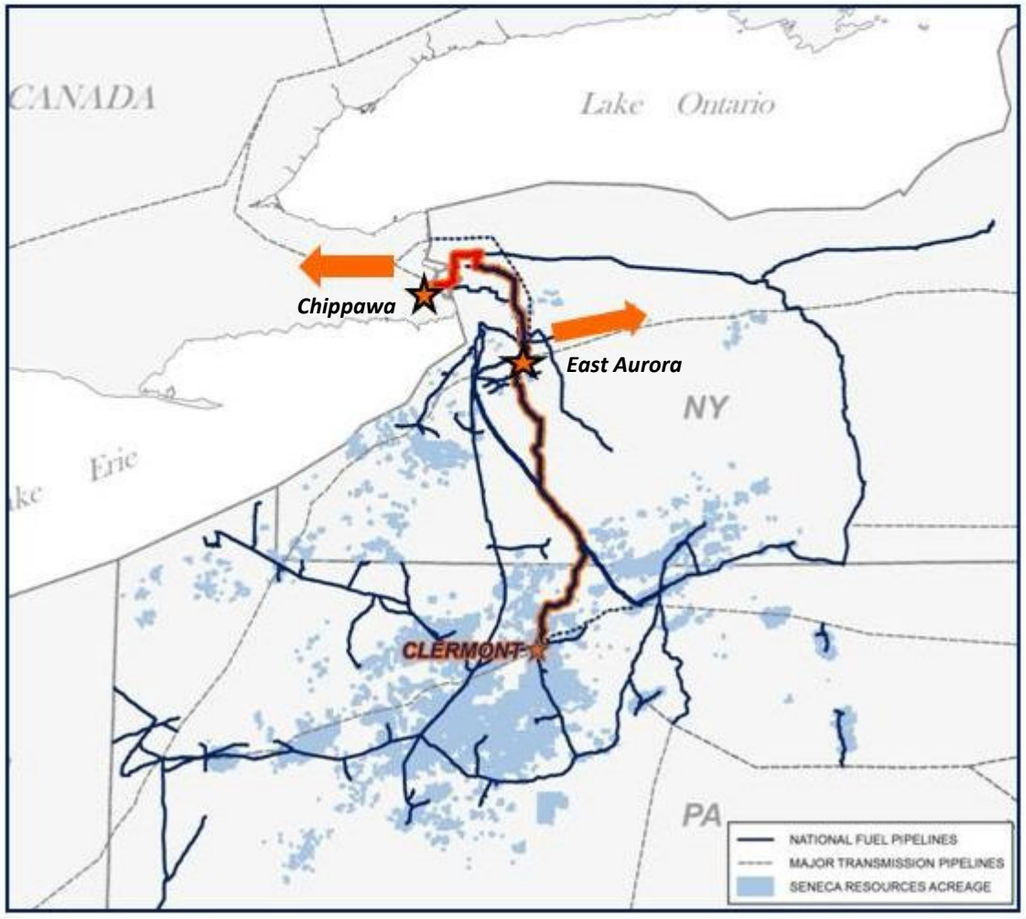


(1) 40,000 Dth per day went in-service on November 1, 2015. The remaining 100,000 Dth per day was placed in-service on December 1, 2015.

Integrated WDA Development - Interstate Pipelines

Pipeline & Storage | Appalachia

Northern Access 2016 to Increase Transport Capacity out of WDA to Canada by 490,000 Dth/d by FY18



Northern Access 2016

- Customer: Seneca Resources (NFG)
- In-Service: Now targeting Nov. 1, 2017
- Capacity: 490,000 Dth/d
- Delivery Interconnects:
  - TransCanada – Chippawa (350 MDth/d)
  - TGP 200 – East Aurora (140 MDth/d)
- Total Cost: ~$455 Million
- Major Facilities:
  - 98.5 miles – 16/24" Pipeline
  - 22,214 hp & 5,350 hp Compression
- FERC/Regulatory Status:
  - 401 Water Quality Joint Application to NYDEC & USACE: March 2016
  - FERC Environmental Assessment: Expected July 2016

Marcellus Shale: Eastern Development Area

Exploration & Production | Appalachia

EDA Highlights

1 Covington & DCNR Tract 595

- Tioga County, Pa.
- 92 wells(1) with 100 MMcf/d productive capacity
- 75 MMcf/d firm sales/FT for remainder of FY16
- NFG Covington Gathering System
- Opportunity for future Geneseo & Utica dev.

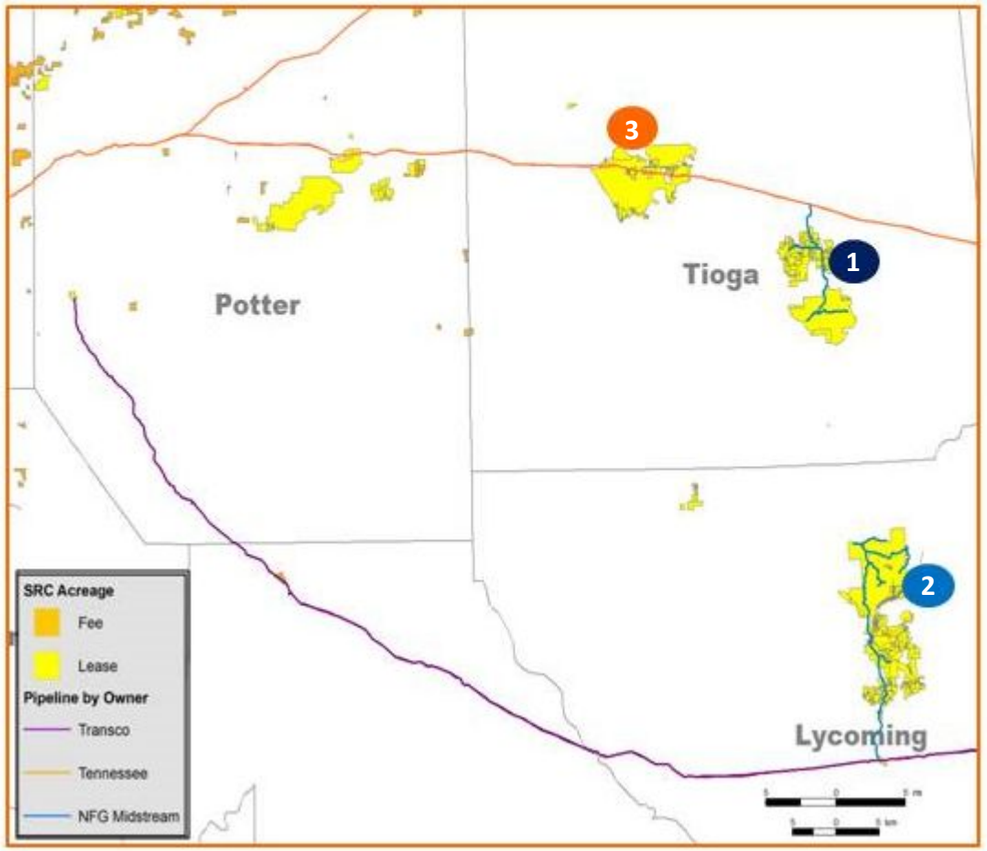
2 DCNR Tract 100 & Gamble

- Lycoming County, Pa.
- 61 wells(1) with 225 MMcf/d productive capacity
- 130 MMcf/d firm sales/FT for remainder of FY16
- Atlantic Sunrise capacity (190 MDth/d) in FY18
- NFG Trout Run Gathering System
- Geneseo to provide additional 100-120 locations

3 DCNR Tract 007

- Tioga County, Pa.
- 1 Utica and 1 Marcellus exploration well
- Utica well 24 IP = 22.7 MMcf/d
- Utica Resource potential = ~1 Tcf

EDA Acreage – 70,000 Acres



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

Integrated EDA Development -Gathering

Gathering | Appalachia

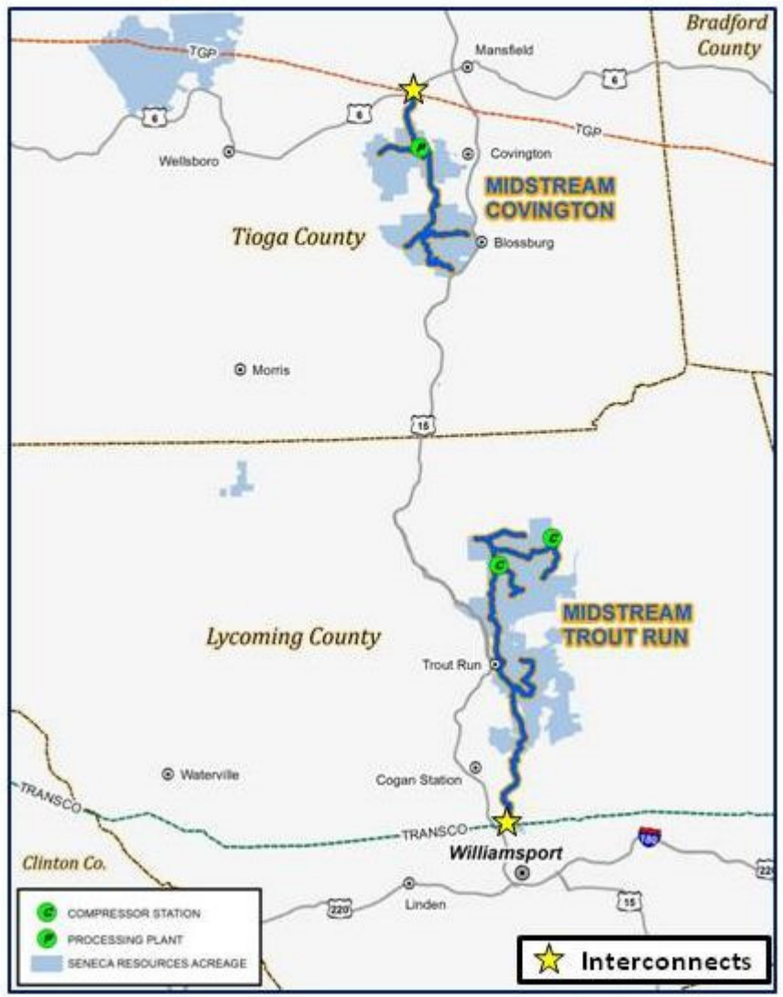
Gathering Segment Supporting Seneca's EDA Production & Future Development

Covington Gathering System

- **In-Service Date:** November 2009
- **Capital Expenditures (to date):** $33 Million
- **Capacity:** 220,000 Dth per day
- **Production Source**: Seneca Resources – Tioga Co. (Covington and DCNR Tract 595 acreage)
- **Interconnect:** TGP 300
- **Facilities:** Pipelines and dehydration
- Future third-party volume opportunities

Trout Run Gathering System

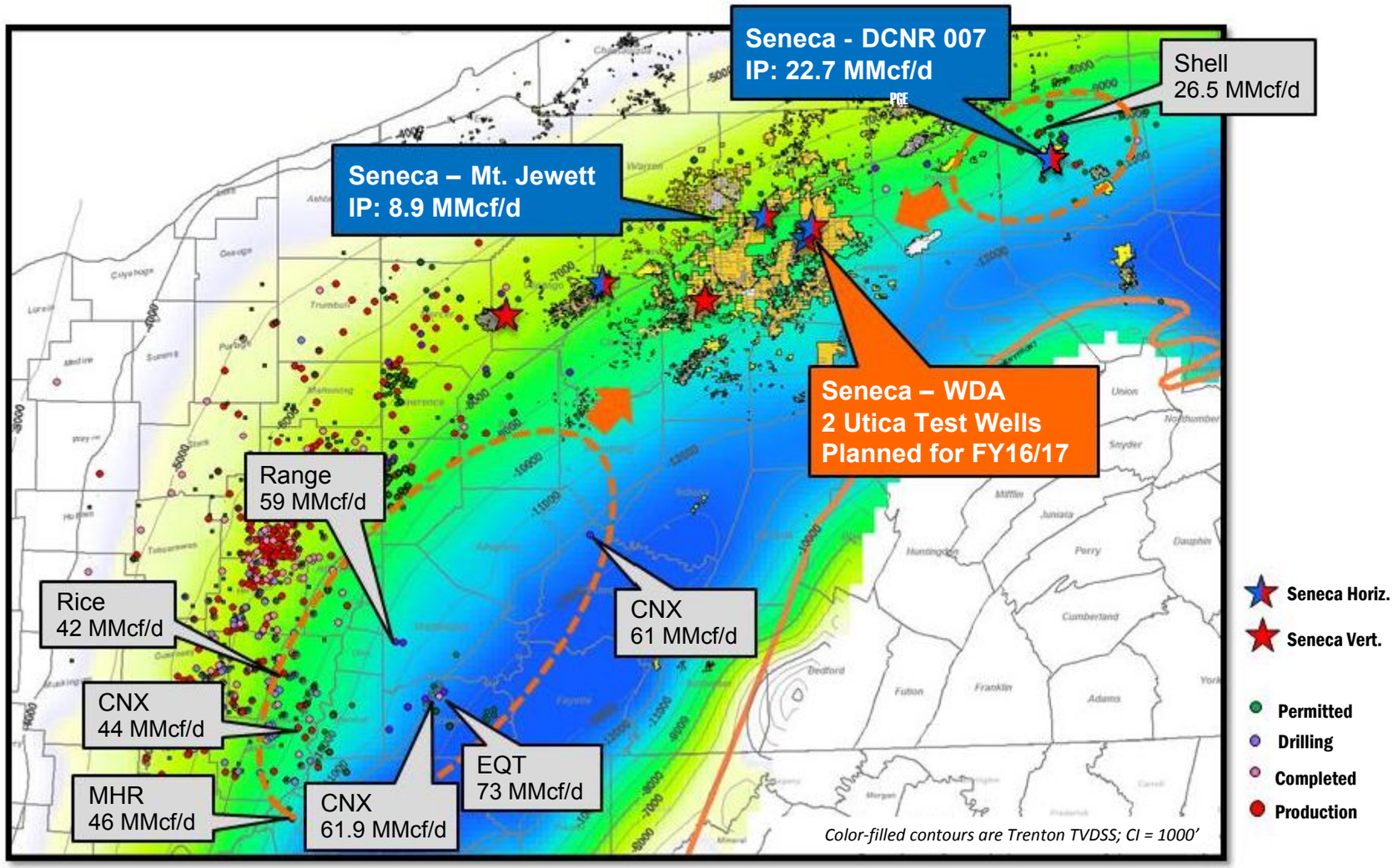
- **In-Service Date:** May 2012
- **Capital Expenditures (to date):** $166 Million
- **Capacity:** 466,000 to 585,000 Dth per day
- **Production Source:** Seneca Resources – Lycoming Co. (DCNR Tract 100 and Gamble acreage)
- **Interconnect:** Transco – Leidy Lateral
- **Facilities:** Pipelines, compression, and dehydration
- Future third-party volume opportunities



Utica Shale Opportunities in EDA & WDA

SENECA RESOURCES

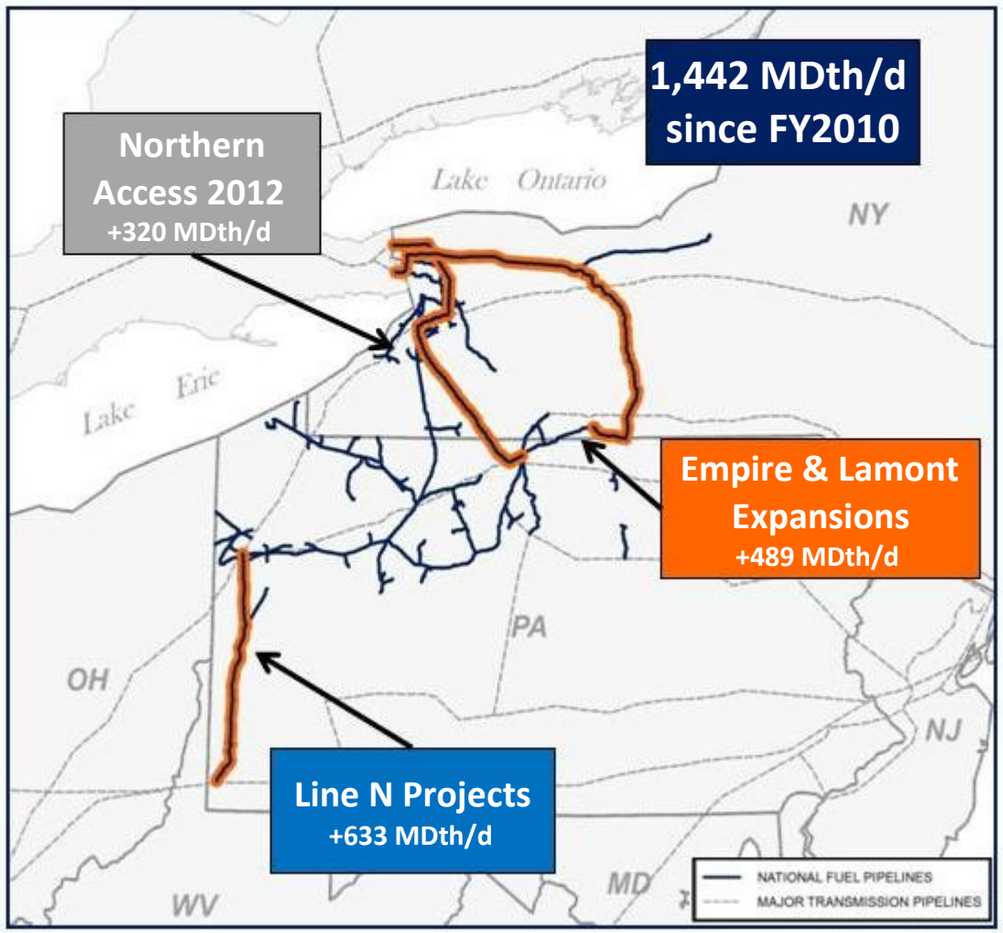
Exploration & Production — **Appalachia**



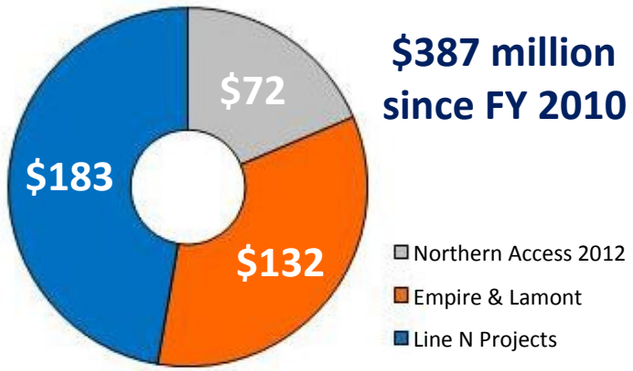
Recent 3rd Party Expansions Highly Successful

Pipeline & Storage | Appalachia

Expansions for 3rd Parties since 2010



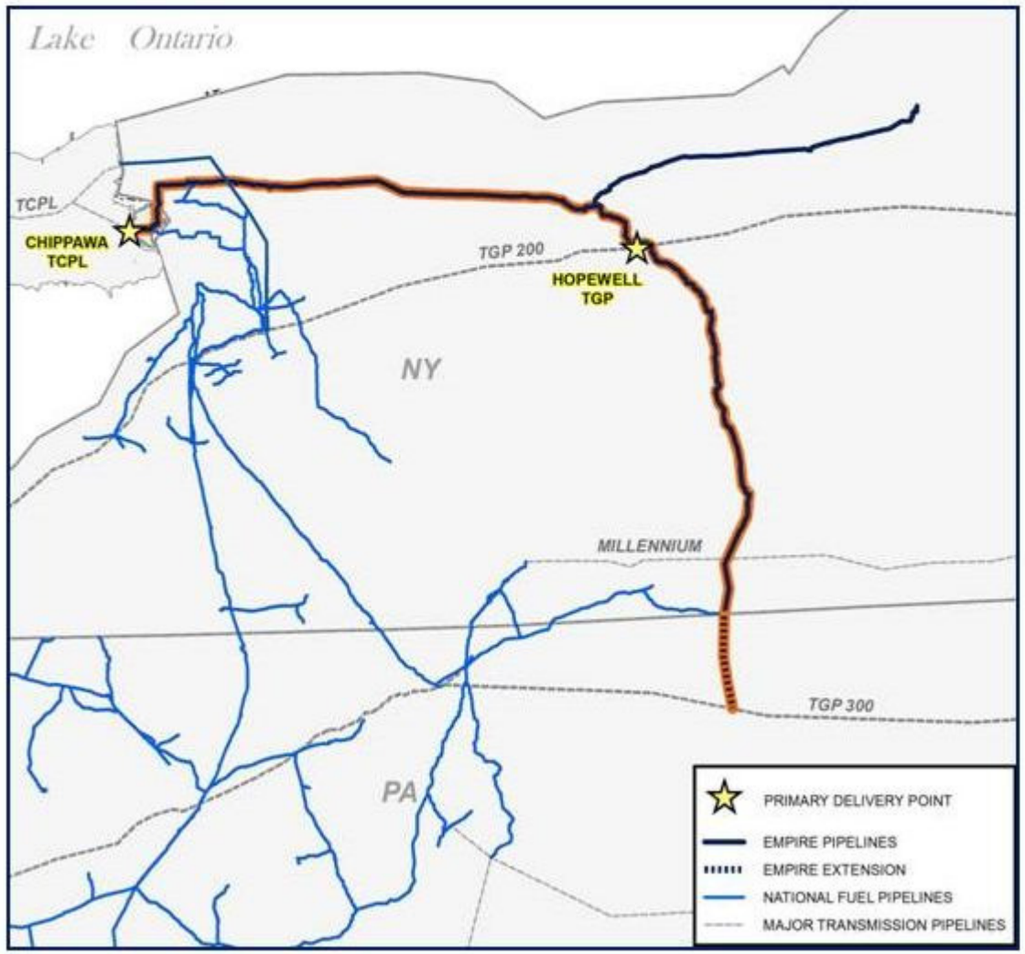
3rd Party Expansion Capital Cost ($MM)



Annual Expansion Revenues Added ($MM)

Planned Empire System Expansion

Pipeline & Storage | Appalachia



Empire North Expansion Project

- Target In-Service: Late 2018
- System: Empire Pipeline
- Target Market:
  - Marcellus & Utica producers in Tioga & Potter County, Pa.
- Open Season Capacity: 300,000 Dth/d
- Delivery Points:
  - 180,000 Dth/d to Chippawa(TCPL)
  - Up to 158,000 Dth/d to Hopewell (TGP)
- Estimated Cost: $185 million
- Major Facilities:
  - 3 new compressor stations
- FERC Status:
  - Open Season concluded in Nov. 2015
  - Precedent agreements tendered in February 2016

2015 Pipeline Expansion Projects In-Service

Pipeline & Storage | Appalachia

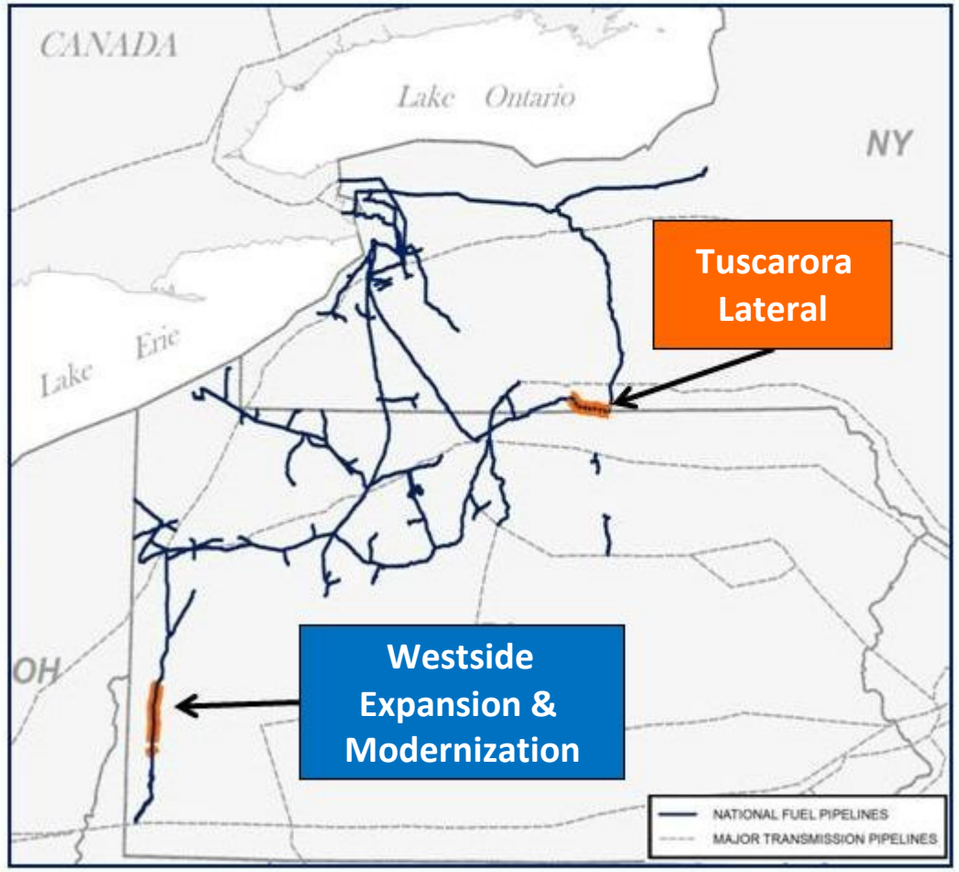
Westside Expansion & Modernization
In-Service (October 2015)

- Total Cost: $86 million
  - Expansion: $45 million
  - Modernization: $41 million
- Incremental Annual Revenues: $8.8 million
- Capacity: 175,000 Dth per day
  - Range Resources (145,000 Dth/d)
  - Seneca Resources (30,000 Dth/d)

Tuscarora Lateral
In-Service (November 2015)

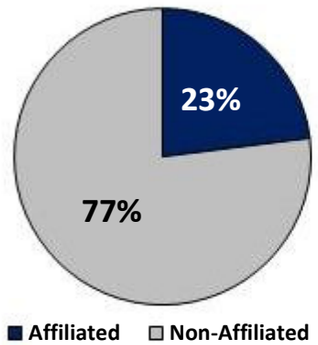
- Total Cost: $60.0 million
- Incremental annual revenues of $10.9 million on 49,000 Dth per day capacity
- Preserves $16.1 million in annual revenues on existing FT (192,500 Dth/d) and retained storage (3.3 Bcf) services

2015 Completed Pipeline Expansion Projects

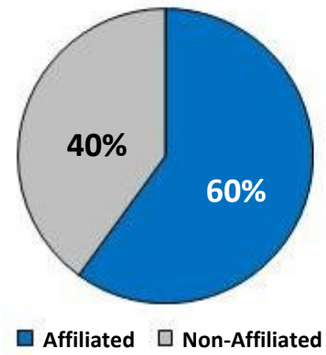


Pipeline & Storage Customer Mix

FT Capacity - Marketers

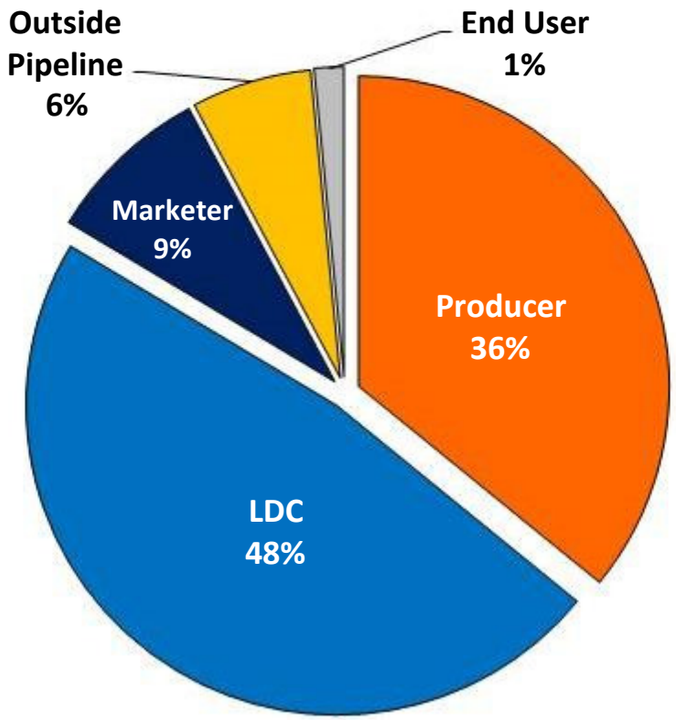


FT Capacity - LDCs

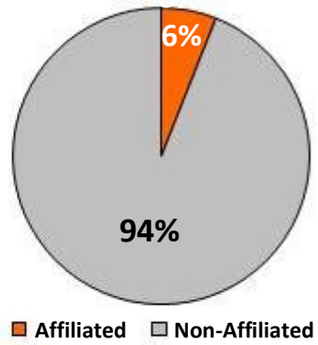


Contracted Transportation by Shipper Type(1)

4.1 MMDth/d

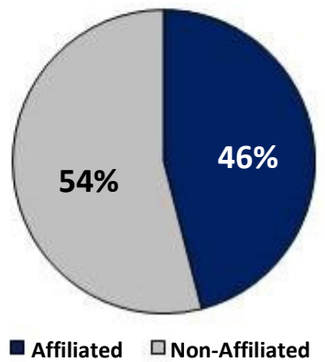


FT Capacity - Producers



Firm Storage Capacity

68 MMDth

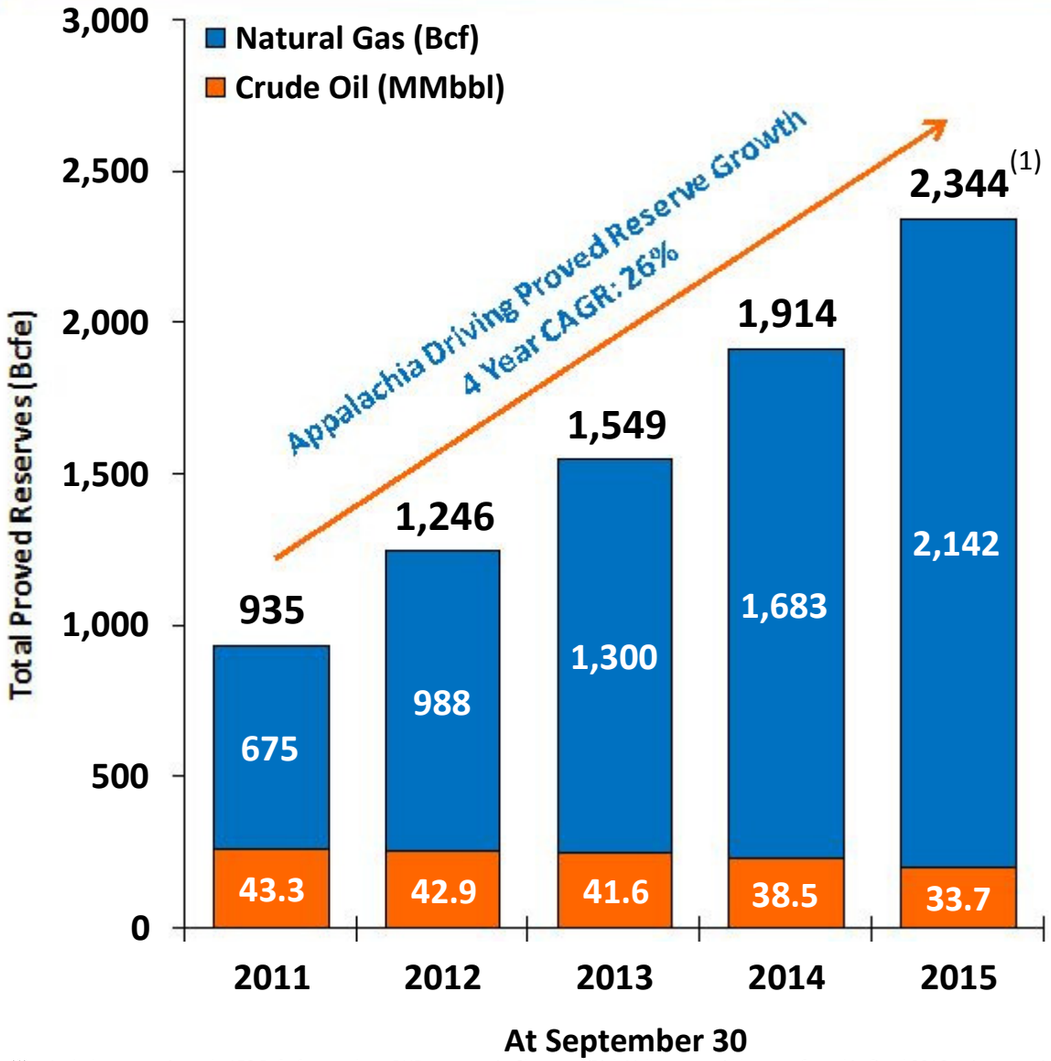


(1) Contracted as of 1/15/2016.

Production and Marketing

Exploration & Production

Proved Reserves & Development Costs

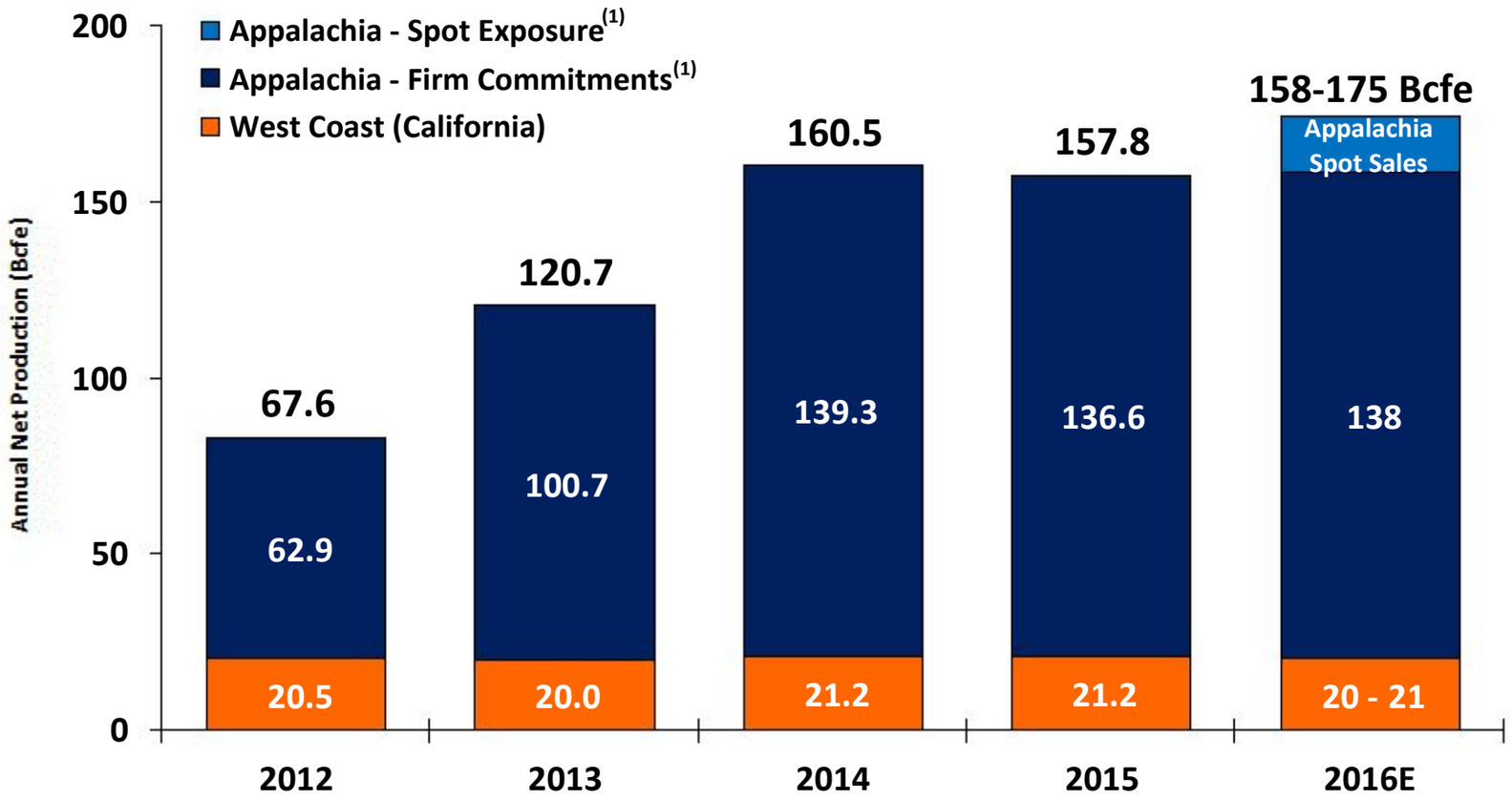


Fiscal Years	3-Year F&D Cost(2) ($/Mcfe)
2008-2010	$2.37
2009-2011	$2.09
2010-2012	$1.87
2011-2013	$1.67
2012-2014	$1.38
2013-2015	$1.12

- **2015 F&D Cost = $0.96**
  - Marcellus F&D: $0.79
- **373% Reserve Replacement Rate**
- **65% Proved Developed**

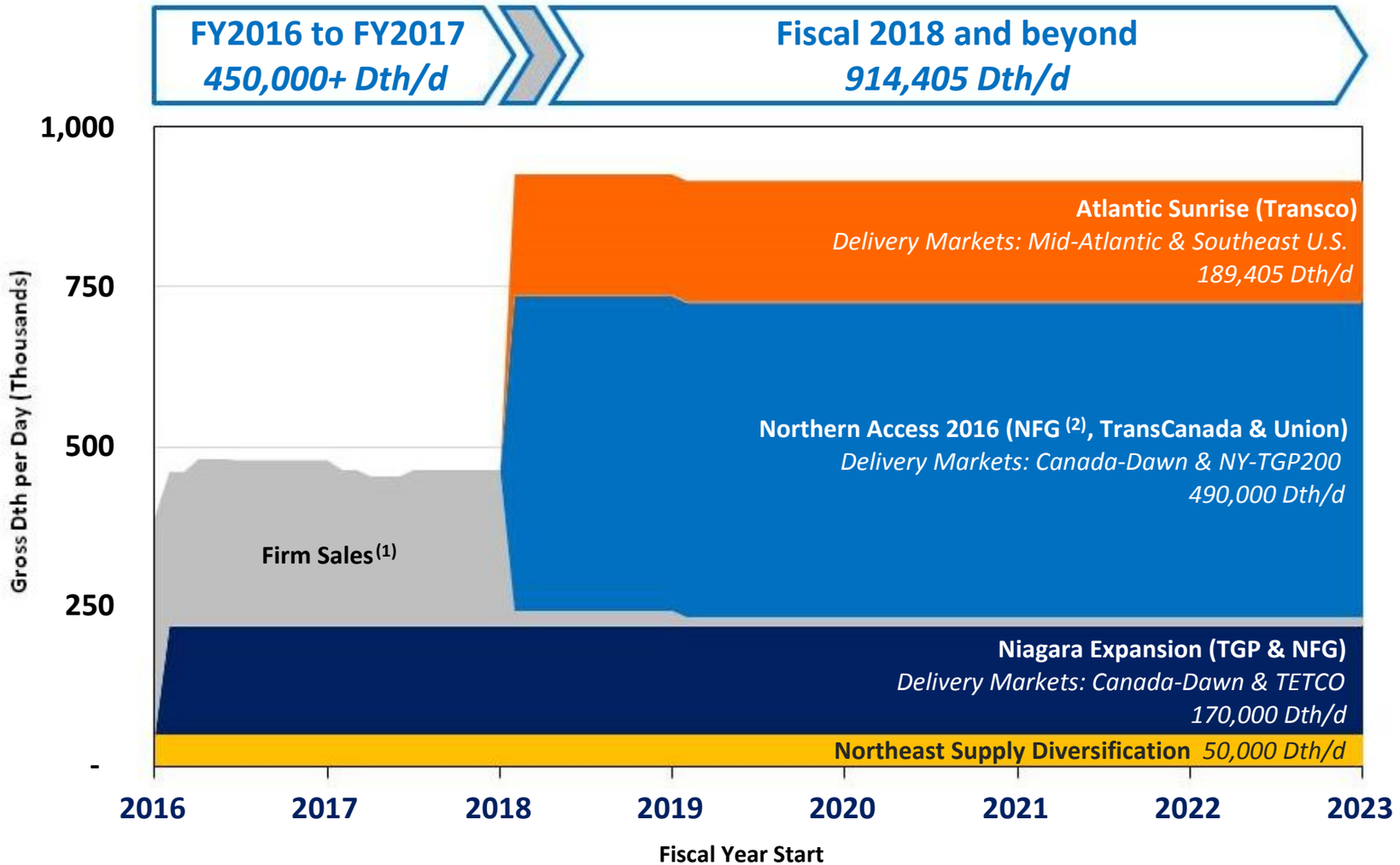
(1) Includes approximately 150 Bcf of natural gas PUD reserves in Clermont/Rich Valley that will be transferred in fiscal 2016 as interests in the joint development wells are conveyed to the partner.
(2) Represents a three-year average U.S. finding and development cost.

Seneca Production



(1) Refer to slide 31 for additional details on fiscal 2016 firm sales and local Appalachian spot market exposure.

Significant Base of Long-Term Firm Contracts



(1) Includes base firm sales contracts not tied to firm transportation capacity. Base firm sales are either fixed priced or priced at an index (e.g., NYMEX) +/- a fixed basis and do not carry any transportation costs. See slide 29 for details on firm sales portfolio for fiscal 2016.

(2) Includes capacity on both National Fuel Gas Supply Corp. and Empire Pipeline, Inc., both wholly owned subsidiaries of National Fuel Gas Company.

Firm Transportation Commitments

Production & Marketing

		Production Source	Volume (Dth/d)	Delivery Market	Demand Charges ($/Dth)	Gas Marketing Strategy
Currently In-Service	**Northeast Supply Diversification Project** *Tennessee Gas Pipeline*	EDA -Tioga County Covington & Tract 595	50,000	Canada (Dawn)	$0.50 (3rd party)	Firm Sales Contracts 50,000 Dth/d Dawn/NYMEX+ 10 years
Currently In-Service	**Niagara Expansion** *TGP & NFG*	WDA – Clermont /Rich Valley	158,000	Canada (Dawn)	NFG pipelines = $0.29 3rd party = $0.38	Firm Sales Contracts 140,000 Dth/d Dawn/NYMEX+ 15 years
			12,000	TETCO (SE Pa.)	NFG pipelines = $0.12	
Future Capacity	**Northern Access** *NFG – Supply & Empire In-Service: Nov. 1 2017*	WDA – Clermont /Rich Valley	350,000	Canada (Dawn)	NFG pipelines = $0.50 3rd party = $0.20	Firm Sales Contracts 145,000 Dth/d Dawn/Fixed Price First 3 years
			140,000	TGP 200 (NY)	NFG pipelines = $0.38	
Future Capacity	**Atlantic Sunrise** *WMB - Transco In-service: Late 2017(1)*	EDA - Lycoming County Tract 100 & Gamble	189,405	Mid-Atlantic/ Southeast	$0.73 (3rd party)	Firm Sales Contracts 189,405 Dth/d NYMEX+ First 5 years

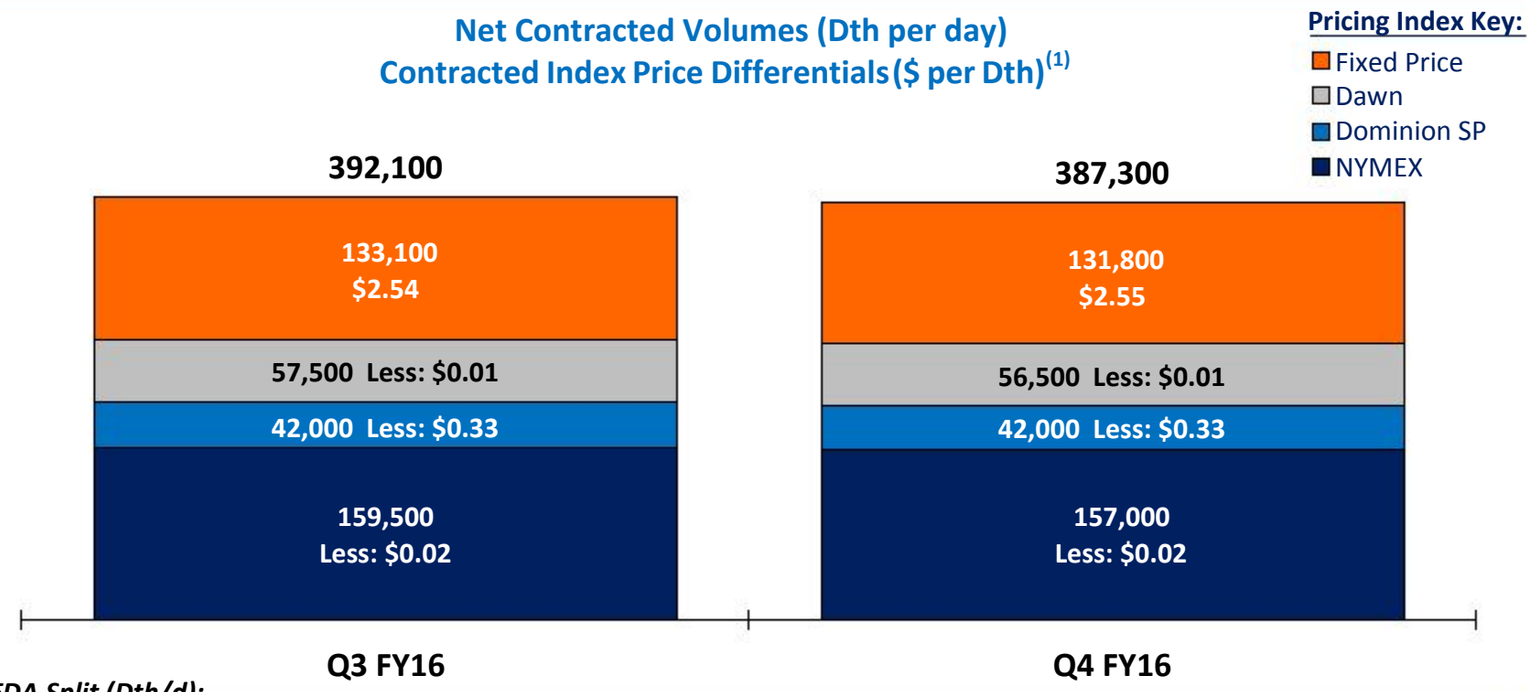
	FY16/FY17	FY18+
Weighted Average Transportation Charge on Volumes Transported	$0.60/Dth	$0.63/Dth
Annualized Gross FT Demand Charges – 3rd Parties	$31 MM	$107 MM
Annualized Gross FT Charges – NFG Affiliates	$17 MM	$88 MM

(1) WMB is now targeting second half of calendar 2017 following the change in the timing of the environmental review from FERC.

Firm Sales Provide Market for Appalachian Production

Fiscal 2016 Firm Sales by Fiscal Quarter

Net Contracted Volumes (Dth per day)
Contracted Index Price Differentials ($ per Dth)[1]



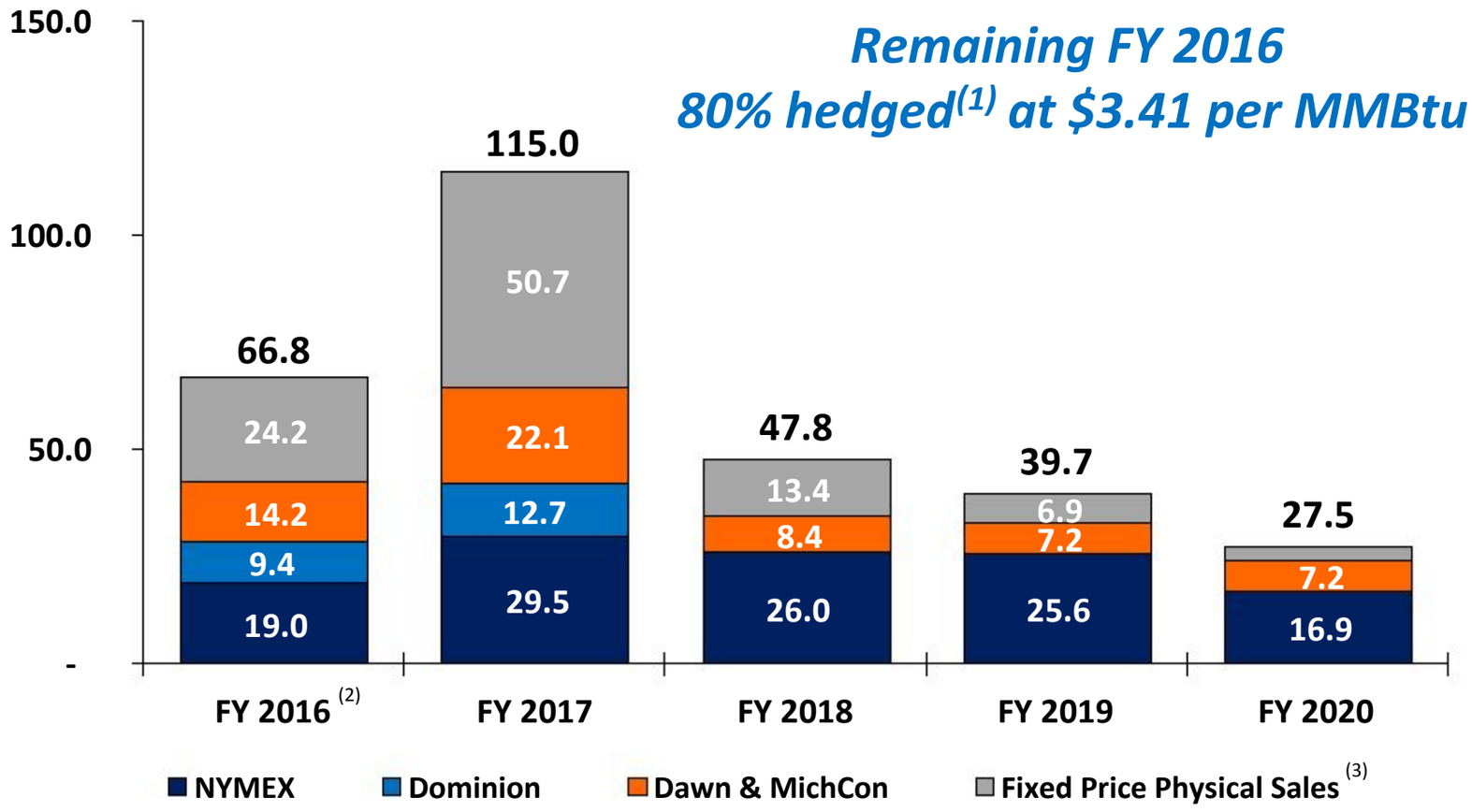
WDA/EDA Split (Dth/d):

	Q3 FY16 Gross	Q3 FY16 Net[2]	Q4 FY16 Gross	Q4 FY16 Net[2]
WDA	263,000/d	208,500/d	263,000/d	203,700/d
EDA	205,100/d	183,600/d	205,100/d	183,600/d
Total	468,100/d	392,100/d	468,100/d	387,300/d

(1) Values shown represent the price or differential to a reference price (netback price) at the point of sale.
(2) Reflects net firm sales volumes after impact of lease royalties in EDA and net revenue interests assigned to joint development partner on certain contracts in WDA.

Strong Hedge Book in Fiscal 2016 and 2017

Natural Gas Swap & Fixed Physical Sales Contracts (Million MMBtu)

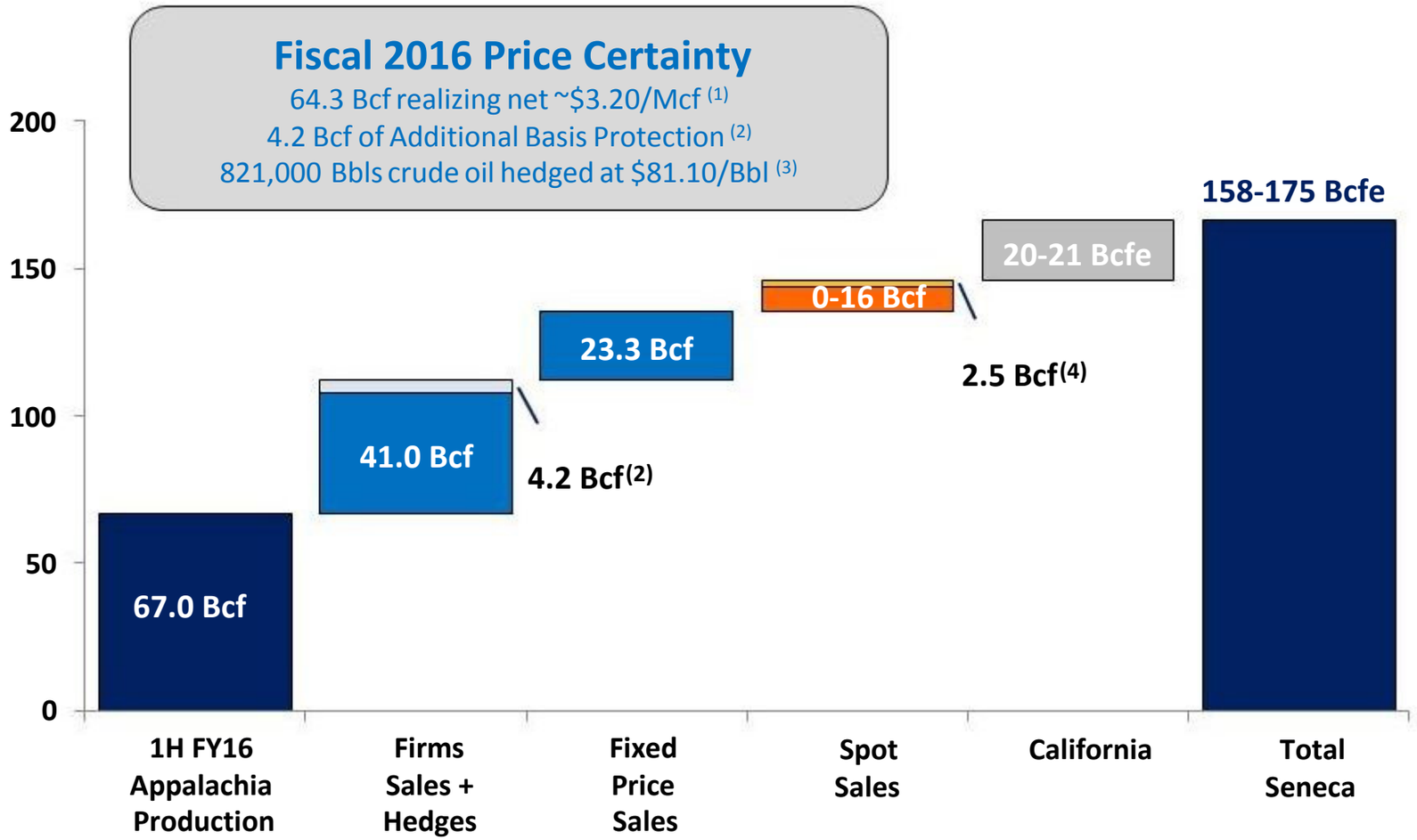


(1) Assumes midpoint of natural gas production guidance, adjusted for year-to-date actual results.

(2) For the remaining six months ended September 30, 2016.

(3) Fixed price physical sales exclude joint development partner's share of fixed price contract WDA volumes as specified under the joint development agreement.

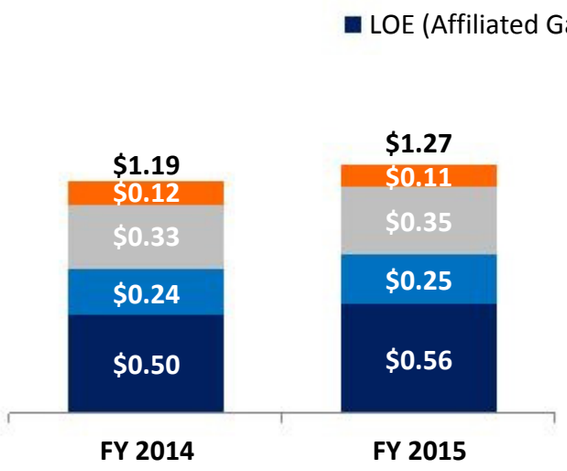
FY 2016 Production – Firm Sales & Spot Exposure



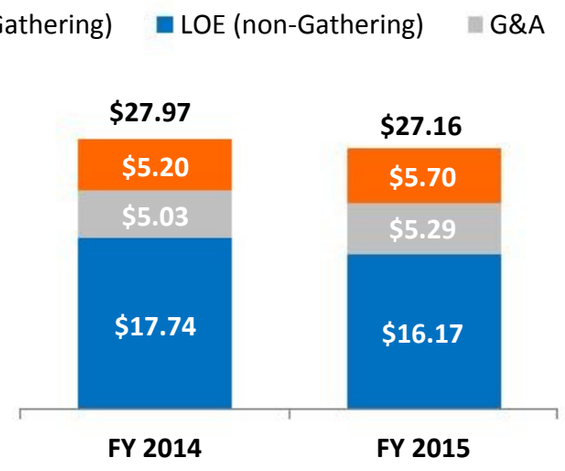
(1) Average realized price reflects uplift from financial hedges less fixed differentials under firm sales contracts and firm transportation costs.
(2) Indicates firm sales contracts with fixed index differentials to NYMEX but not backed by a matching NYMEX financial hedge.
(3) Represents 55% of remaining projected oil production at the midpoint of guidance.
(4) Represents 2.5 Bcf of non-operated production from Western Development Area .

Operating Costs

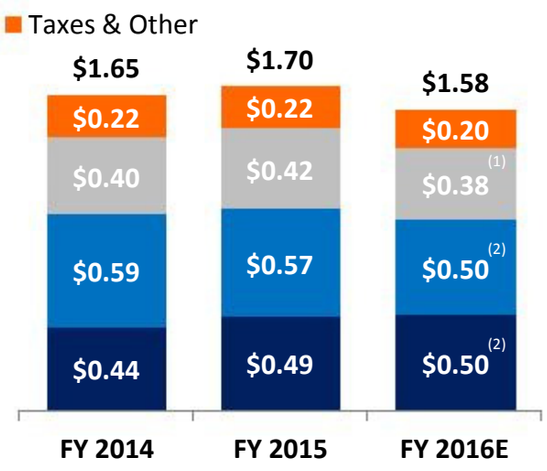
Appalachia Division *$/Mcfe*



West Division (California) *$/Boe*



Seneca Resources Consolidated *$/Mcfe*



DD&A *$/Mcfe*

- ✓ Competitive, low cost structure in Appalachia and California supports strong cash margins
- ✓ Gathering fee generates significant revenue stream for affiliated gathering company
- ✓ DD&A decrease due to improving Marcellus F&D costs ($0.79 /Mcf in FY15) and reduction in net plant resulting from ceiling test impairments

(1) Excludes $4.7 million of professional fees relating to the joint development agreement announced in December 2015.
(2) The total of the two LOE components represents the midpoint of LOE guidance of $0.95 to $1.05 per Mcfe for fiscal 2016.

National Fuel

California Overview

Exploration & Production

California

Stable Oil Production | Minimal Capital Investment | Free Cash Flow Positive

East Coalinga
Temblor Formation
Primary

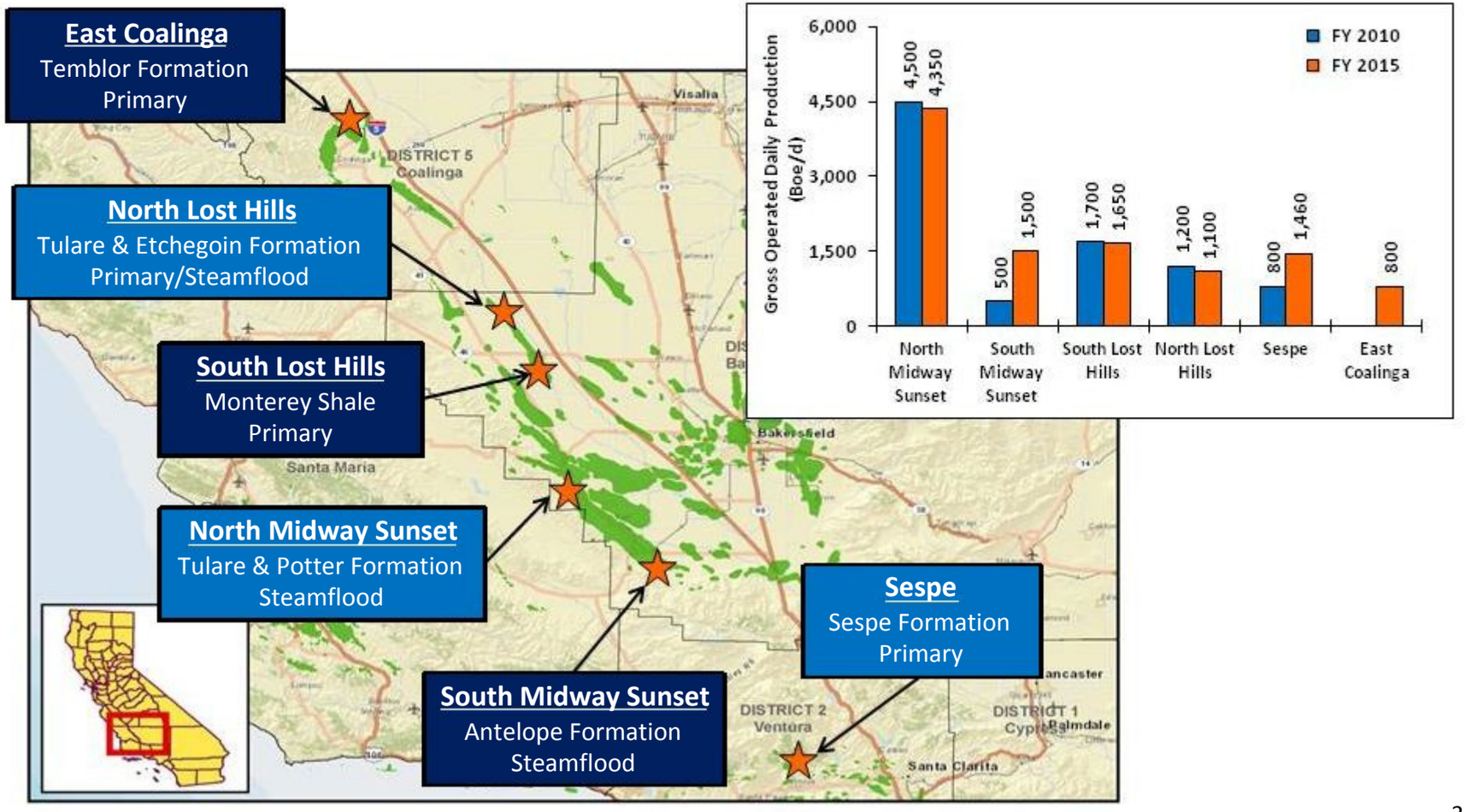
North Lost Hills
Tulare & Etchegoin Formation
Primary/Steamflood

South Lost Hills
Monterey Shale
Primary

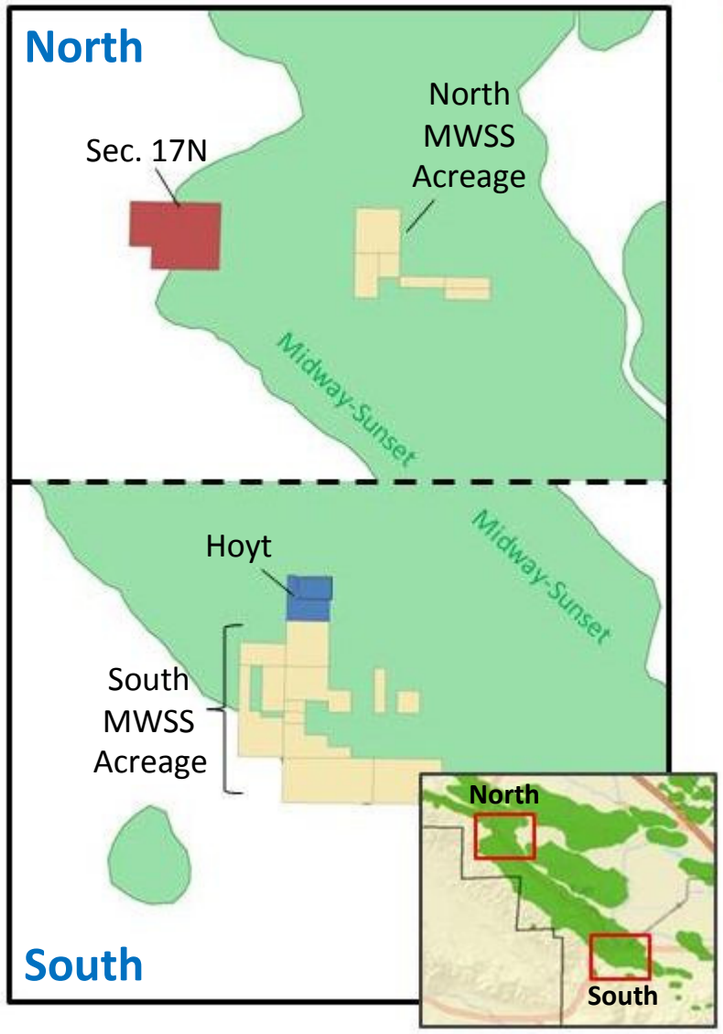
North Midway Sunset
Tulare & Potter Formation
Steamflood

South Midway Sunset
Antelope Formation
Steamflood

Sespe
Sespe Formation
Primary

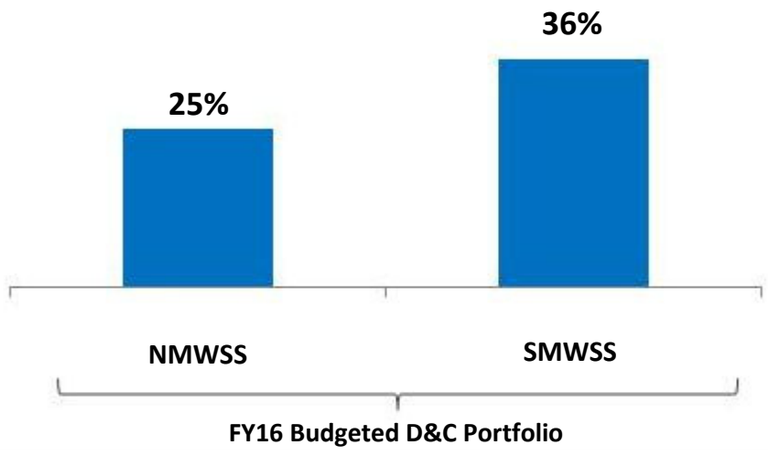


Economic Development Focused on Midway Sunset



Midway Sunset Economics

MWSS Project IRRs at $40/Bbl (1)

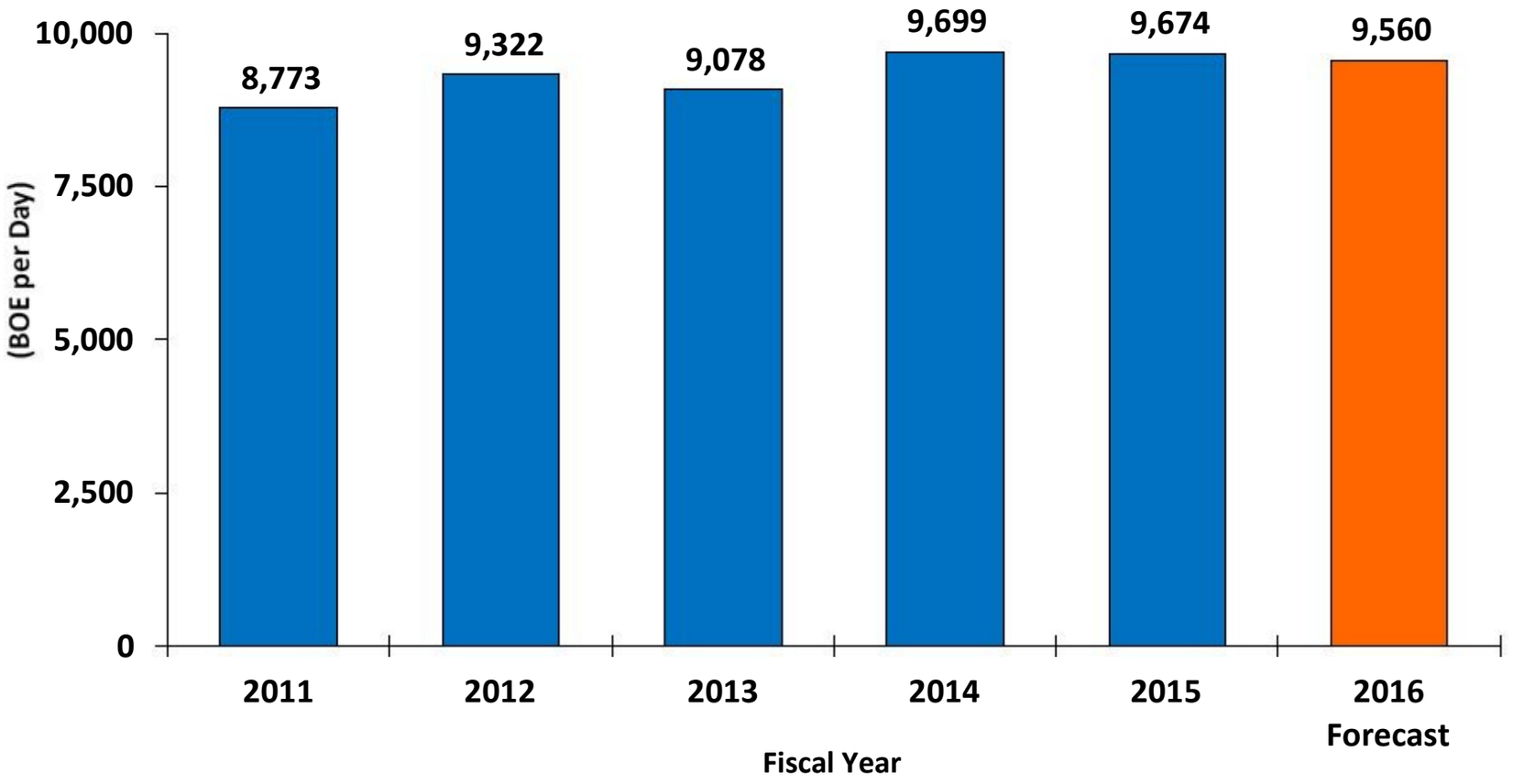


- ✓ Modest near-term capital program focused on locations that earn attractive returns in current oil price environment
- ✓ A&D will focus on low cost, bolt-on opportunities
- ✓ Sec. 17 and Hoyt farm-ins to provide future growth
  - F&D (est.) = $6.50/Boe

(1) Reflects pre-tax IRRs at a $40/Bbl realized price.

California Average Daily Net Production

$35-$40 Million Annual Capital Spending Will Keep CA Production Flat

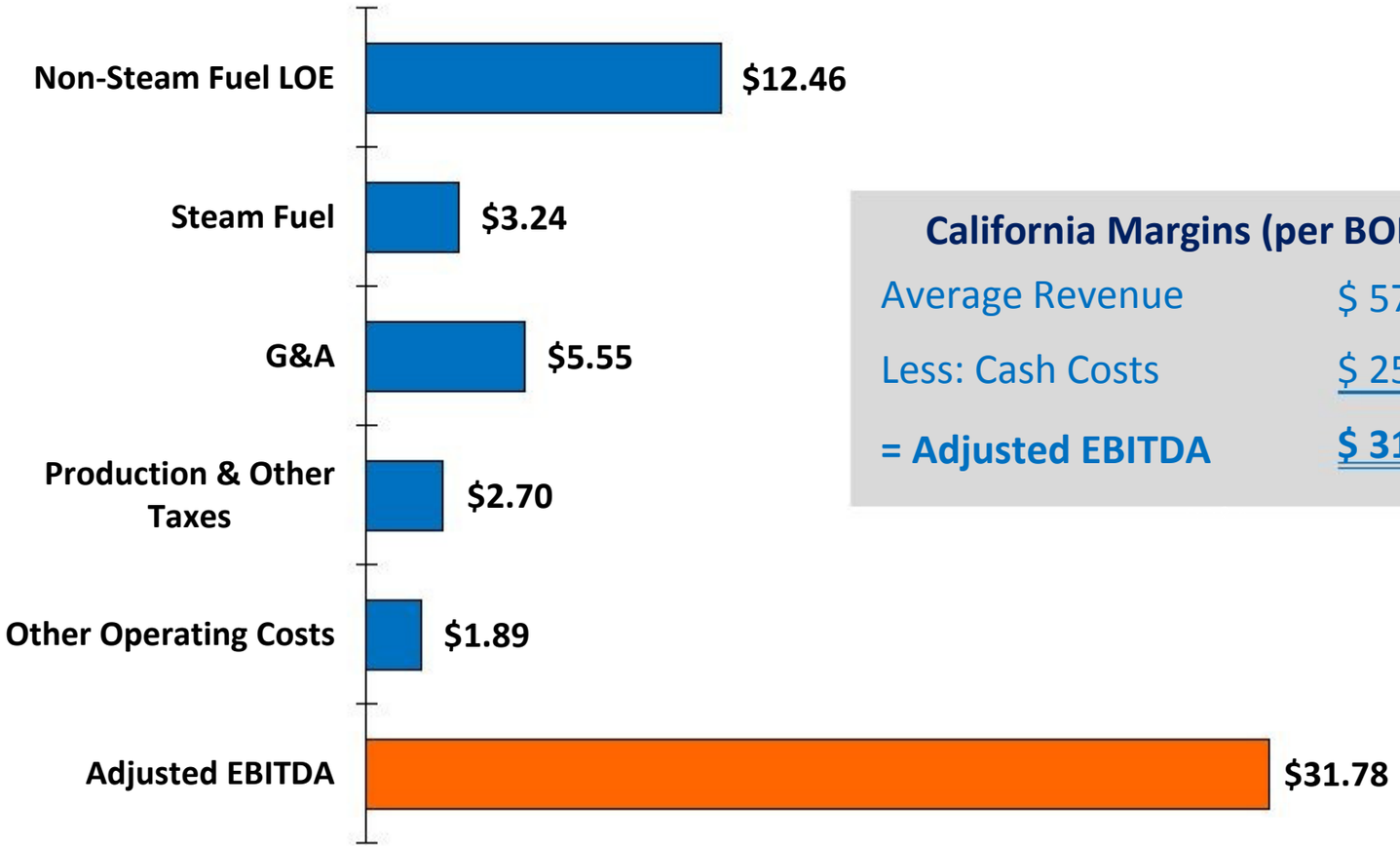


Strong Margins Support Significant Free Cash Flow

Upstream

West Division Adjusted EBITDA per BOE (1)

Trailing 12-months Ended 3/31/16



California Margins (per BOE)	
Average Revenue	$ 57.62
Less: Cash Costs	$ 25.84
= Adjusted EBITDA	**$ 31.78**

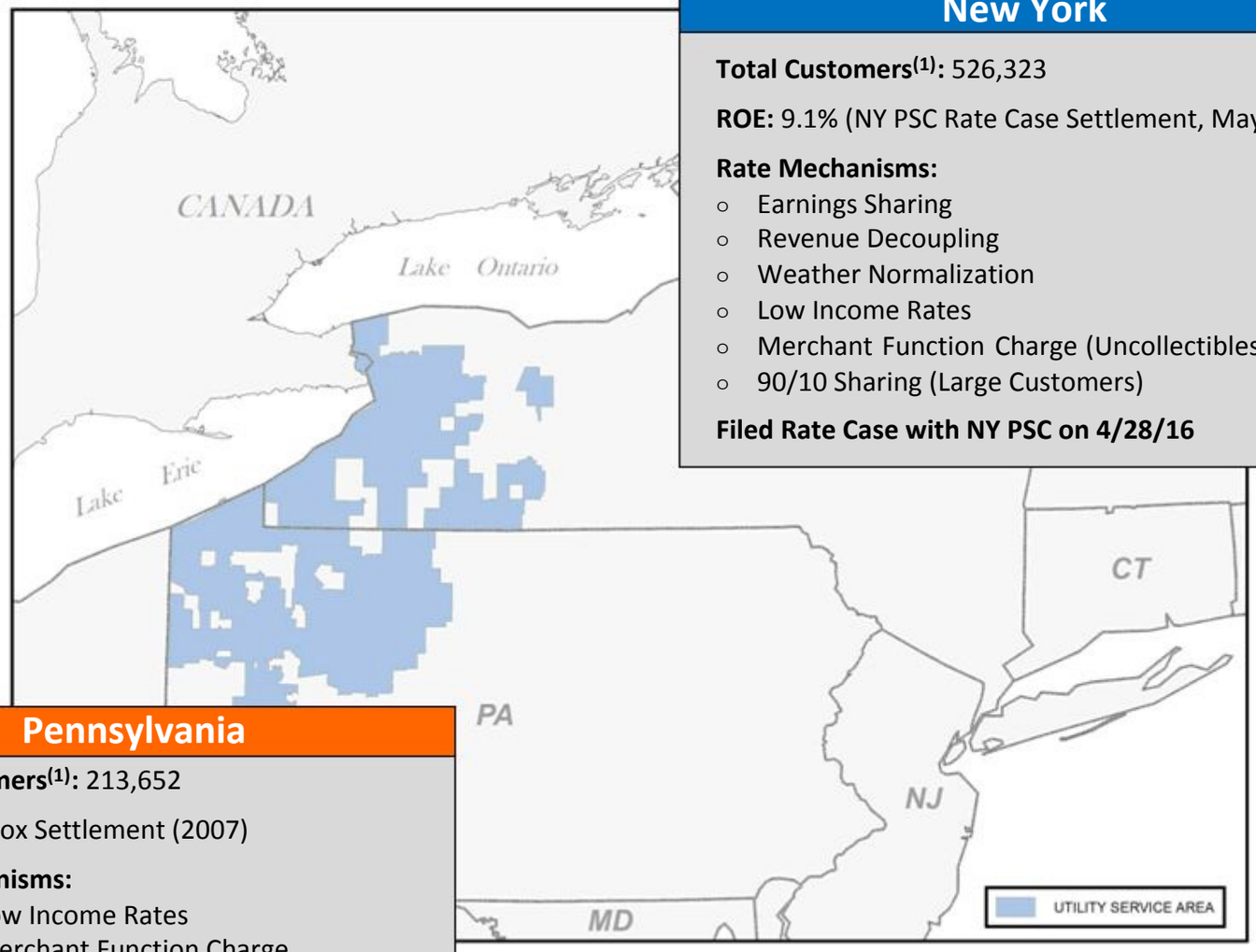
(1) Average revenue per BOE includes impact of hedging and other revenues.

Note: A reconciliation of Adjusted EBITDA margin 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. EBITDA per BOE includes Seneca corporate results and eliminations.

Downstream Overview

Utility | Energy Marketing

New York & Pennsylvania Service Territories



New York

Total Customers[(1)]: 526,323

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)

Filed Rate Case with NY PSC on 4/28/16

Pennsylvania

Total Customers[(1)]: 213,652

ROE: Black Box Settlement (2007)

Rate Mechanisms:

- Low Income Rates
- Merchant Function Charge

(1) As of September 30, 2015.

New York Rate Case

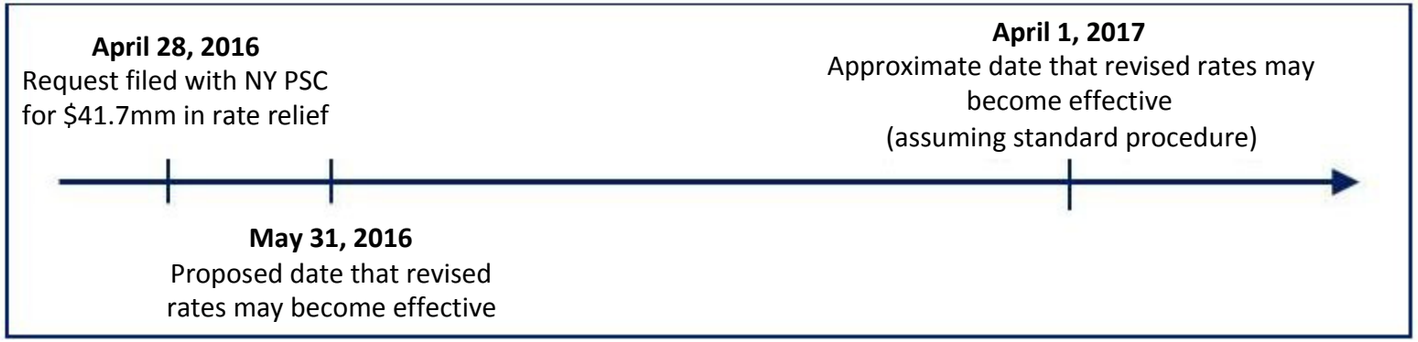
Background

On April 28, 2016, National Fuel Gas Distribution Corporation filed a request with the New York Public Service Commission (NY PSC) to amend its tariff and increase its base rates. National Fuel's base rates have not changed since the last base rate case was litigated in 2007.

Key Drivers

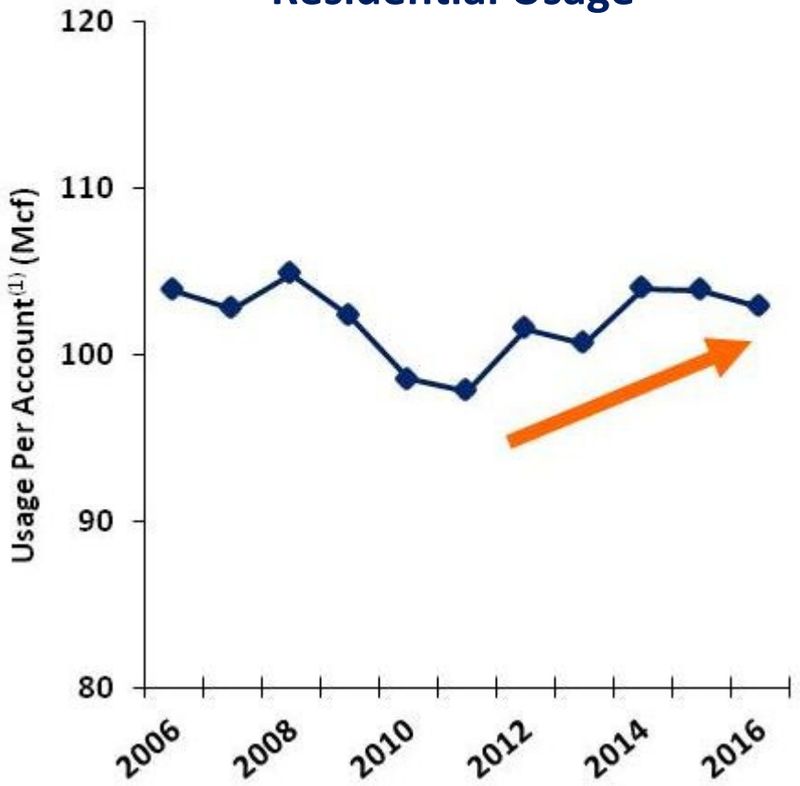
- Requesting rate relief that would increase annual revenues by $41.7 million
- Key drivers of revenue requirement:
  - ✓ Significant increase in net plant - $127.5 million - and related depreciation expense since 9/30/2006, the test year associated with the 2007 rate proceeding
  - ✓ Continued investment in pipeline replacement and system modernization to enhance and ensure safe, reliable service
    - Accelerated removal of vintage pipe from current annual target of 95 miles to 110 miles
    - Replacement of aging information technology infrastructure expected in 2nd half of FY16
  - ✓ Commitment to low income customer, conservation and gas expansion initiatives

Anticipated Timeline



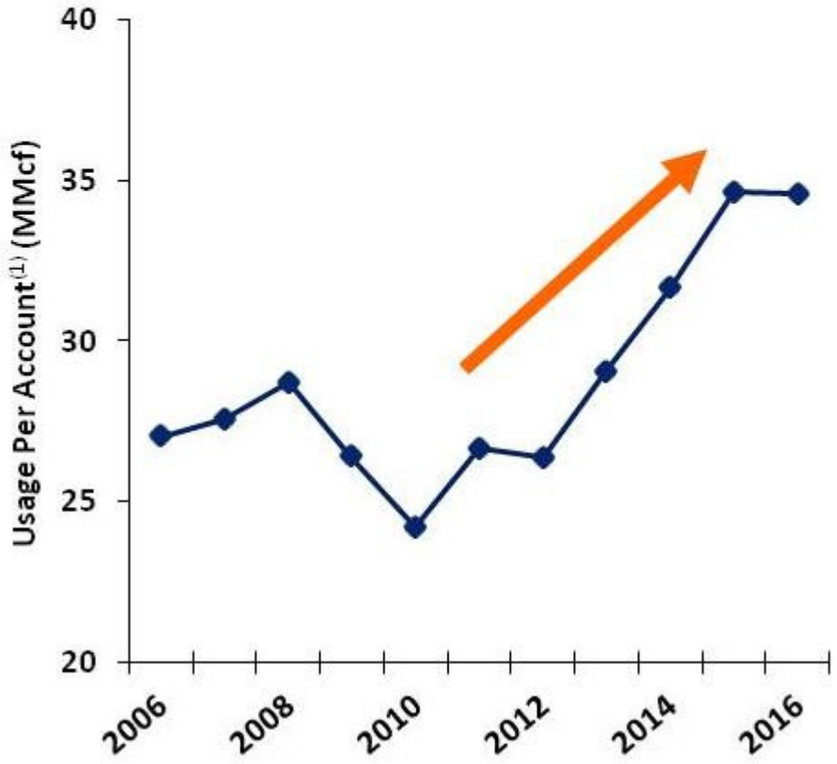
Utility: Shifting Trends in Customer Usage

Residential Usage



12-Months Ended March 31

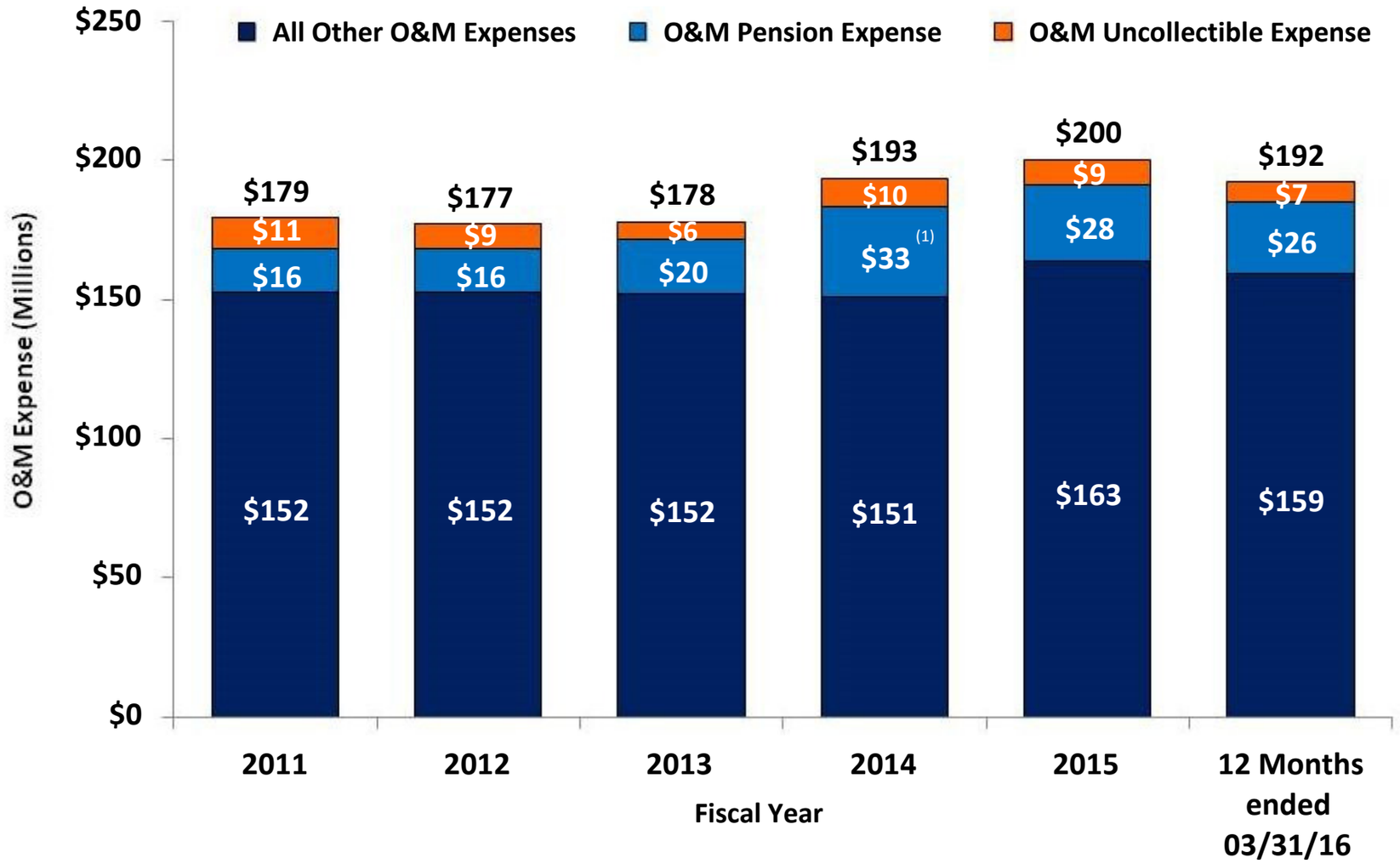
Industrial Usage



12-Months Ended March 31

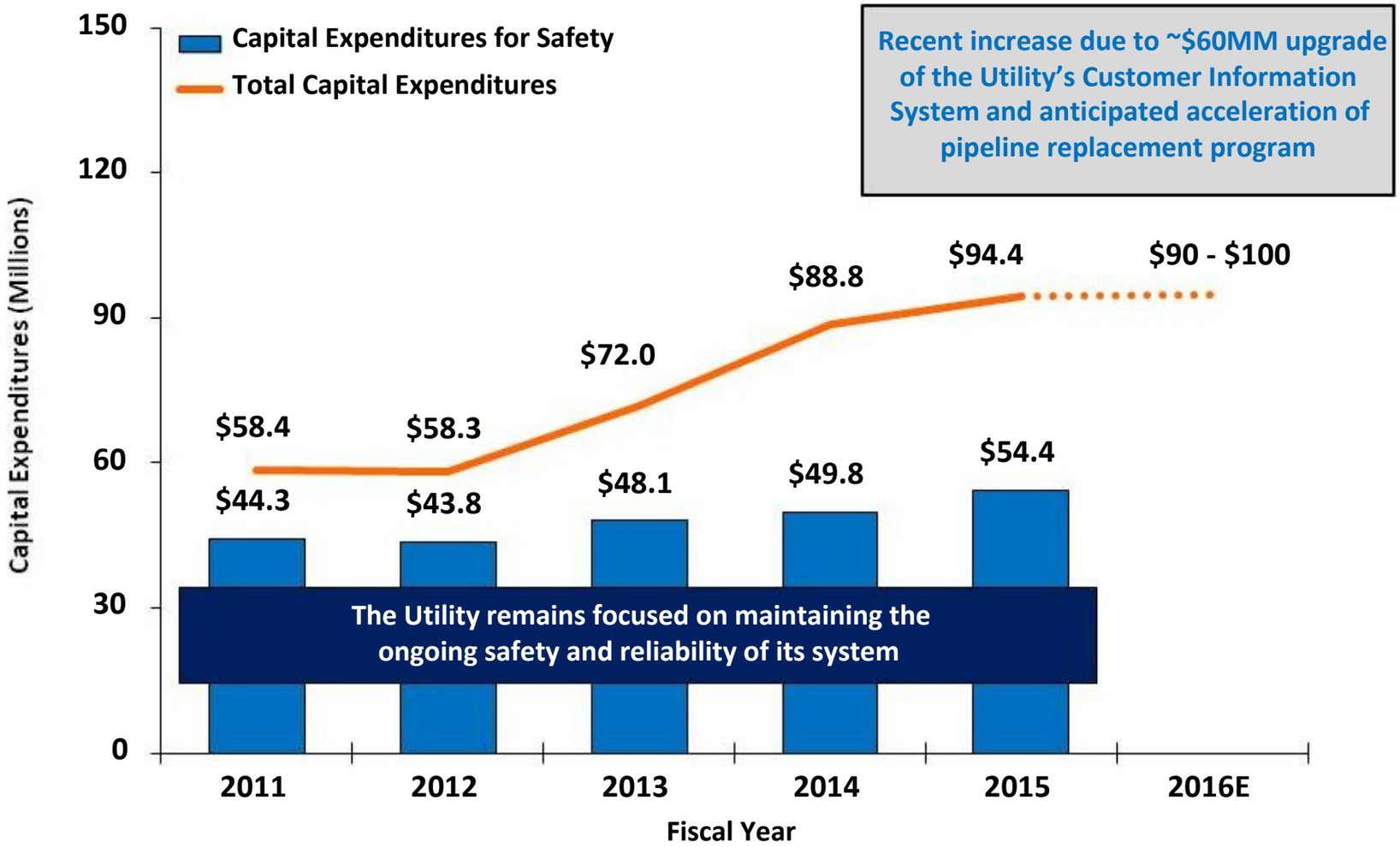
(1) Weighted Average of New York and Pennsylvania service territories (assumes normal weather).

A Proven History of Controlling Costs



(1) $10 million of increase in pension costs from fiscal 2013 primarily due to the NY PSC earnings settlement in May 2014.

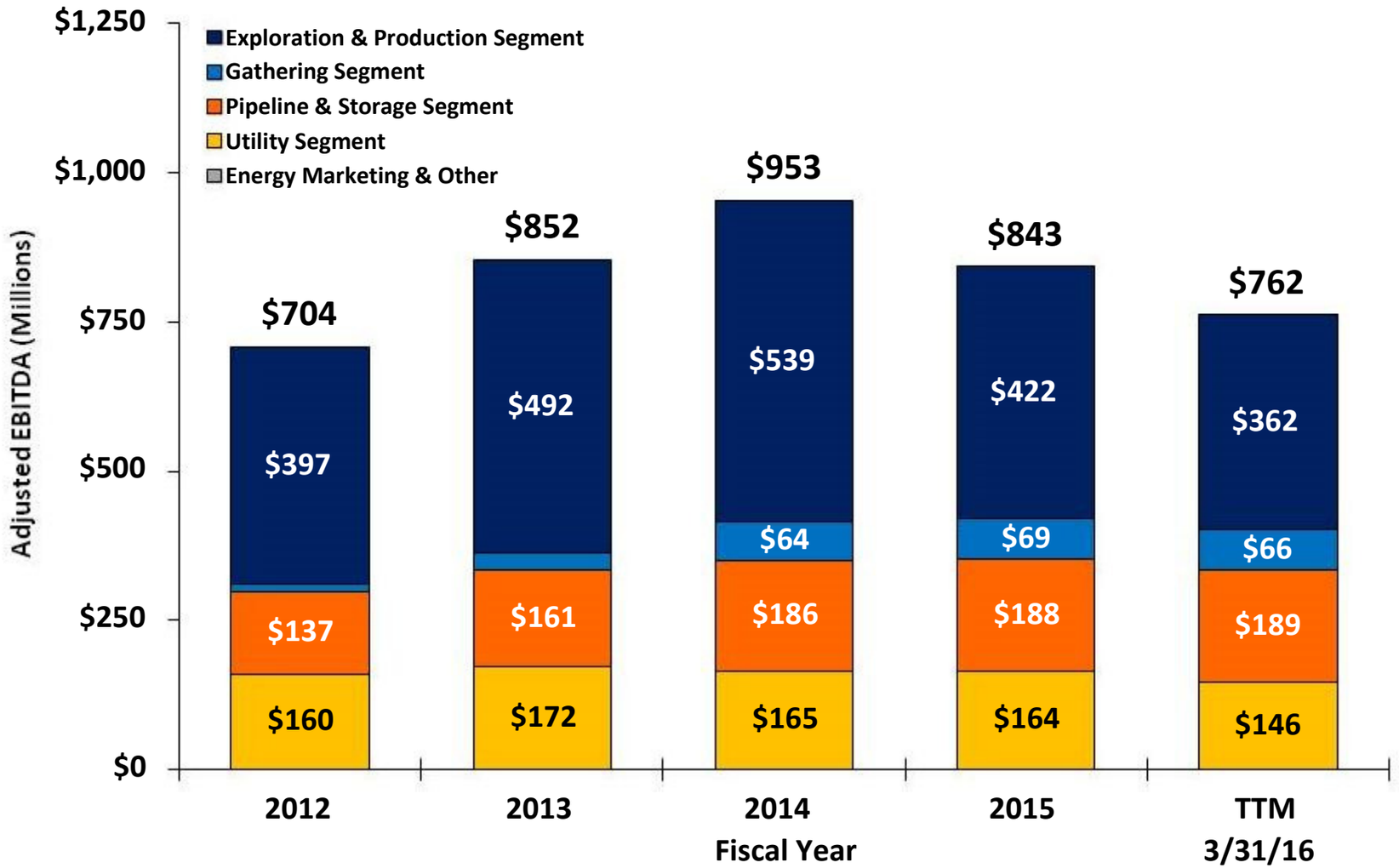
Utility: Strong Commitment to Safety



Consolidated Financial Overview

Upstream | Midstream | Downstream

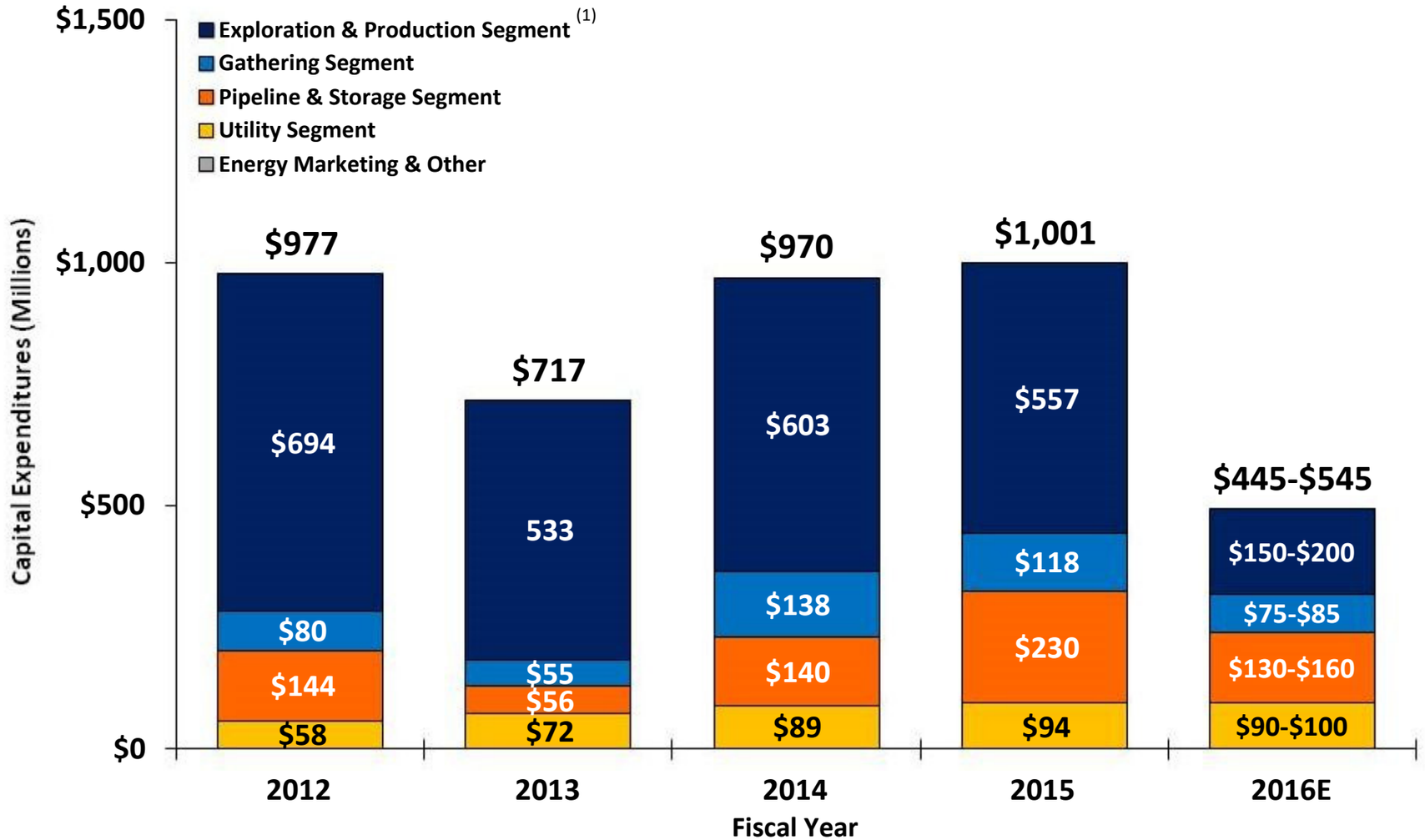
EBITDA Contribution by Segment



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.

Capital Expenditures by Segment

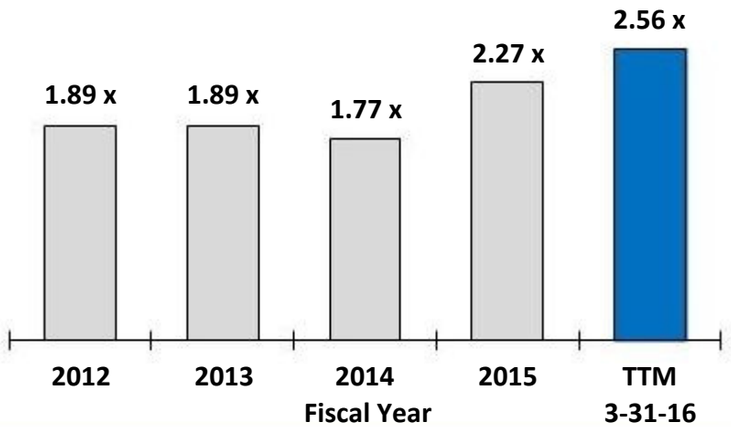
Corporate



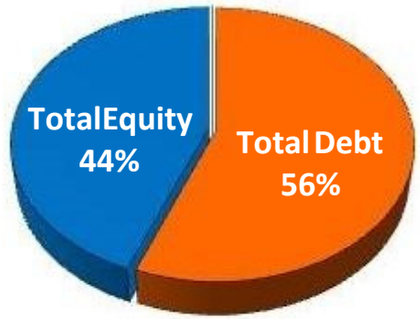
(1) FY2016 capital expenditure guidance reflects the netting of up-front proceeds received from joint development partner for capital spent on wells drilled and/or completed prior to the execution date of the joint development agreement. The E&P segment's FY16 capital budget would be reduced by an additional $90-$110 million if joint development partner exercises right to participate in remaining 38 wells.
Note: A reconciliation to Capital Expenditures as presented on the Consolidated Statement of Cash Flows is included at the end of this presentation.

Financial Position & Liquidity

Debt/Adjusted EBITDA

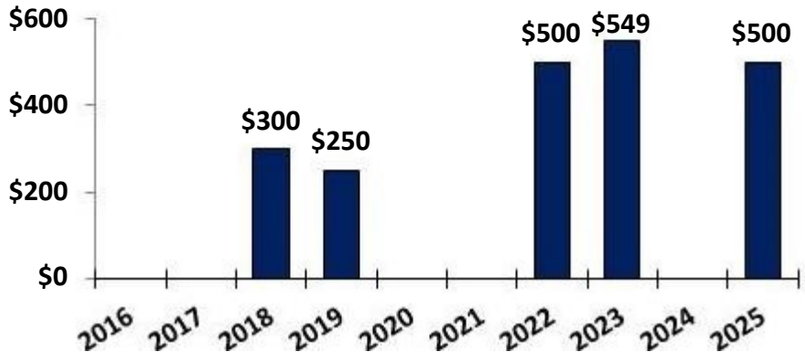


Capitalization



$3.7 Billion Total Capitalization as of March 31, 2016

Debt Maturity Profile ($MM)



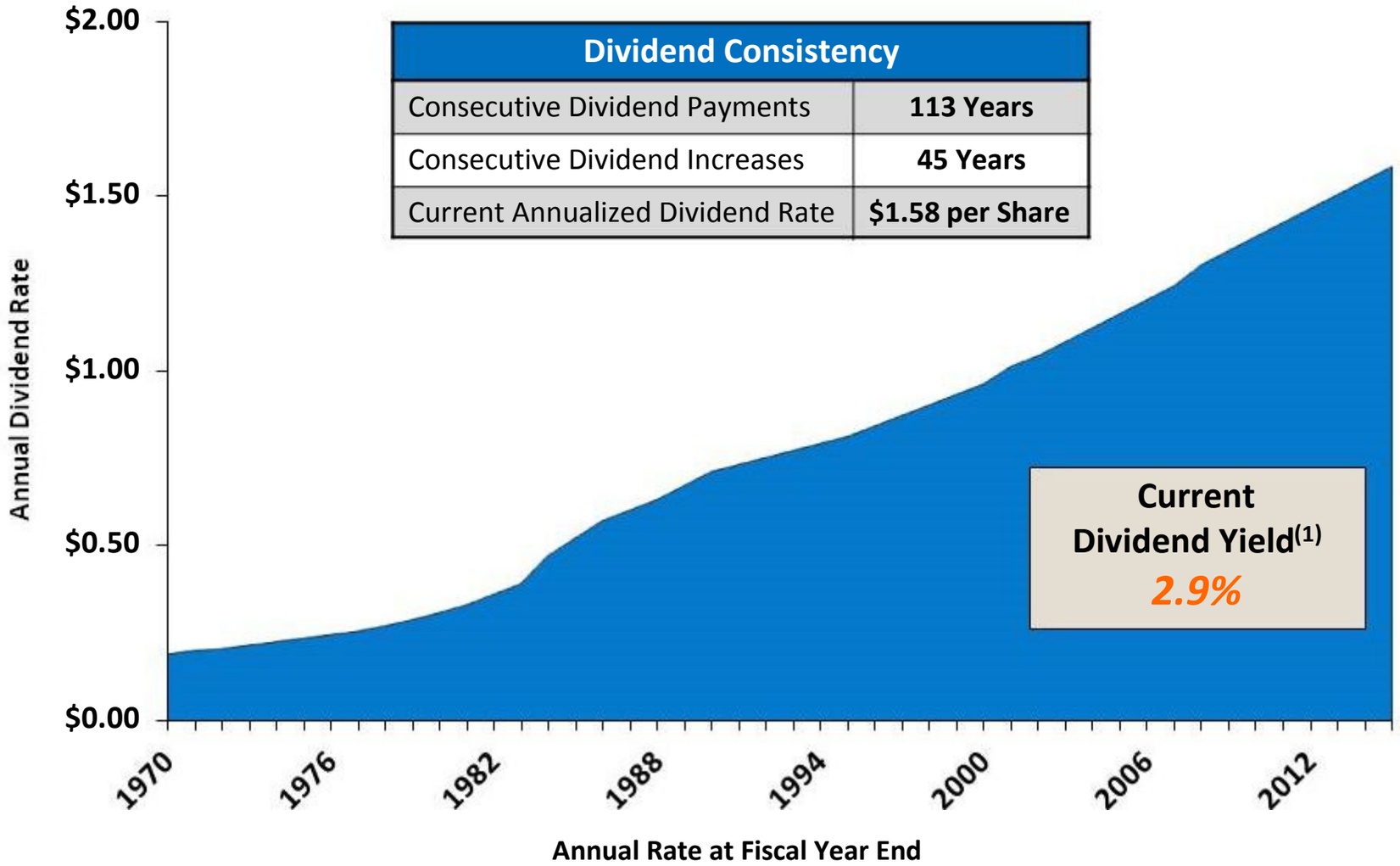
Liquidity

Committed Credit Facilities	$ 1,250 MM
Short-term Debt Outstanding	$ 0 MM
Available Short-term Credit Facilities	$ 1,250 MM
Cash Balance at 03/31/16	$ 94 MM
Total Liquidity at 3/31/16	**$ 1,344 MM**

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

Dividend Track Record

Dividend Consistency	
Consecutive Dividend Payments	**113 Years**
Consecutive Dividend Increases	**45 Years**
Current Annualized Dividend Rate	**$1.58 per Share**



(1) As of April 27, 2016.

The National Fuel Value Proposition

Considerable Upstream and Midstream Growth Opportunities in Appalachia

- ✓ Fee ownership on ~715,000 net acres in WDA = limited royalties or drilling commitments
- ✓ Seneca has >900,000 Dth/day of firm transportation & sales contracts by start of fiscal 2018
- ✓ Stacked pay potential in Utica and Geneseo shales across Marcellus acreage
- ✓ Coordinated gathering & interstate pipeline infrastructure build-out with NFG midstream
- ✓ Opportunity for further pipeline expansion to accommodate Appalachian supply growth

Unique Asset Mix and Integrated Model Provide Balance and Stability

- ✓ Geographical and operational integration drives capital flexibility and reduces costs
- ✓ Cash flow from rate-regulated businesses supports interest costs and funds the dividend

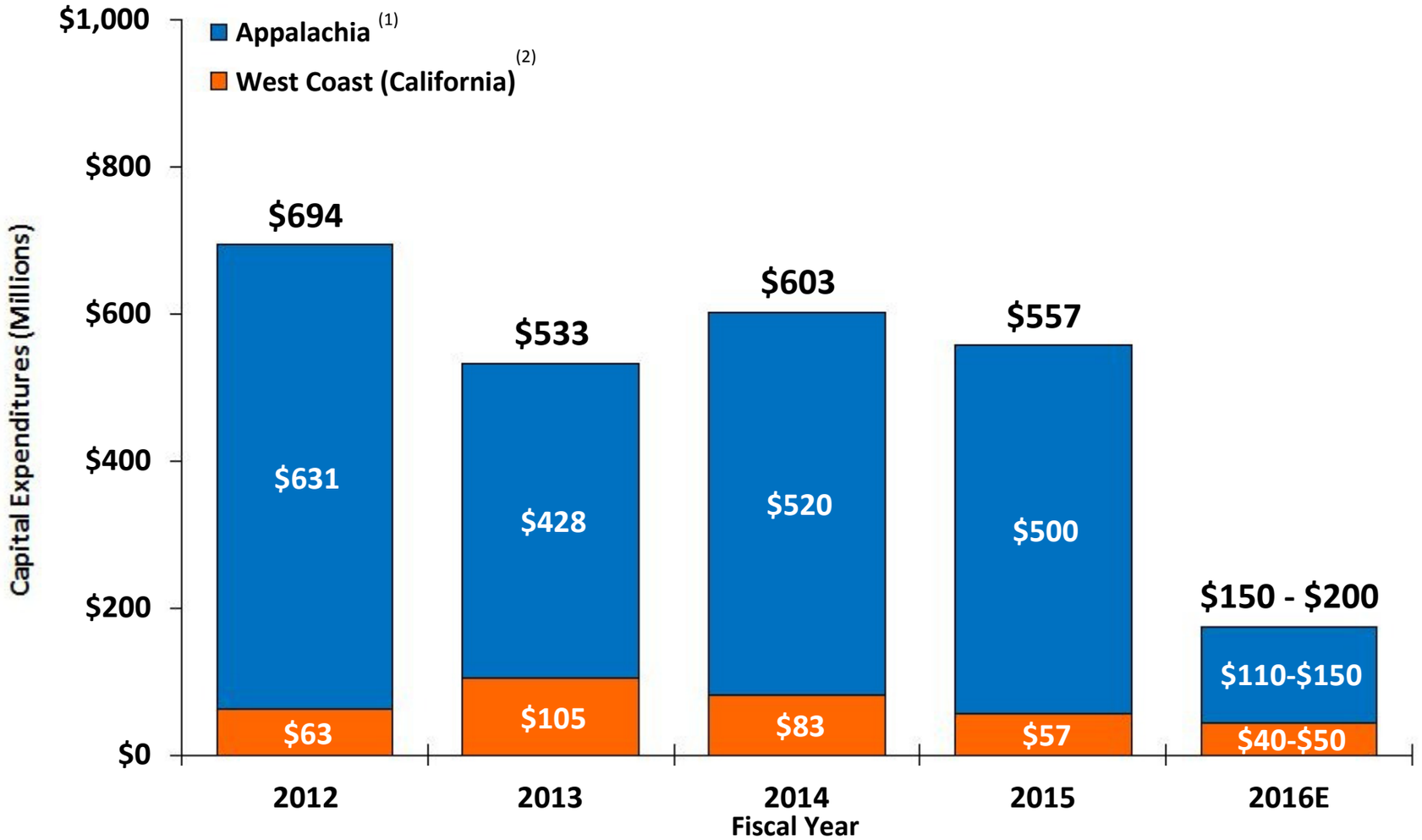
NFG is Well Positioned to Endure Current Commodity Price Environment

- ✓ Investment grade credit rating and liquidity to support long-term Appalachian growth strategy
- ✓ Strong hedge book helps insulate near-term earnings and cash flows from commodity volatility
- ✓ Disciplined and flexible capital investment that is focused on economic returns

Creating long-term sustainable value remains our #1 shareholder priority

Appendix

Total Seneca Capital Spending by Division



(1) FY2016 capital expenditure guidance reflects the netting of up-front proceeds received from joint development partner for capital spent on wells drilled and/or completed prior to the execution date of the joint development agreement. The FY16 capital budget would be reduced by an additional $90-$110 million if joint development partner exercises right to participate in remaining 38 wells.

(2) Seneca's West Coast division includes Seneca corporate and eliminations.

Marcellus Operated Well Results

WDA Development Wells:

Area	Producing Well Count	Average IP Rate (MMcfd)	Average 30-Day (MMcf/d)	Average Treatable Lateral Length (ft)
Clermont/Rich Valley (CRV) & Hemlock *Elk, Cameron & McKean counties*	**86**(1)	**6.9**	**5.2** (1)	**6,970'**

EDA Development Wells:

Area	Producing Well Count	Average IP Rate (MMcfd)	Average 30-Day (MMcf/d)	Average Treatable Lateral Length (ft)
Covington Tioga County	**47**	**5.2**	**4.1**	**4,023'**
Tract 595 Tioga County	**44**(2)	**7.4**	**4.9**	**4,754'**
Tract 100 Lycoming County	**60**(2)	**17.0**	**12.6**	**5,221'**

(1) Excludes 2 wells now operated by Seneca that were drilled by another operator as part of a joint-venture. 30-day average excludes 14 wells that have not been on line 30 days.
(2) Does not include 1 well drilled into and producing from the Geneseo Shale.

Marcellus Shale Program Economics

~1,100 WDA Locations Economic Below $2.25/MMBtu

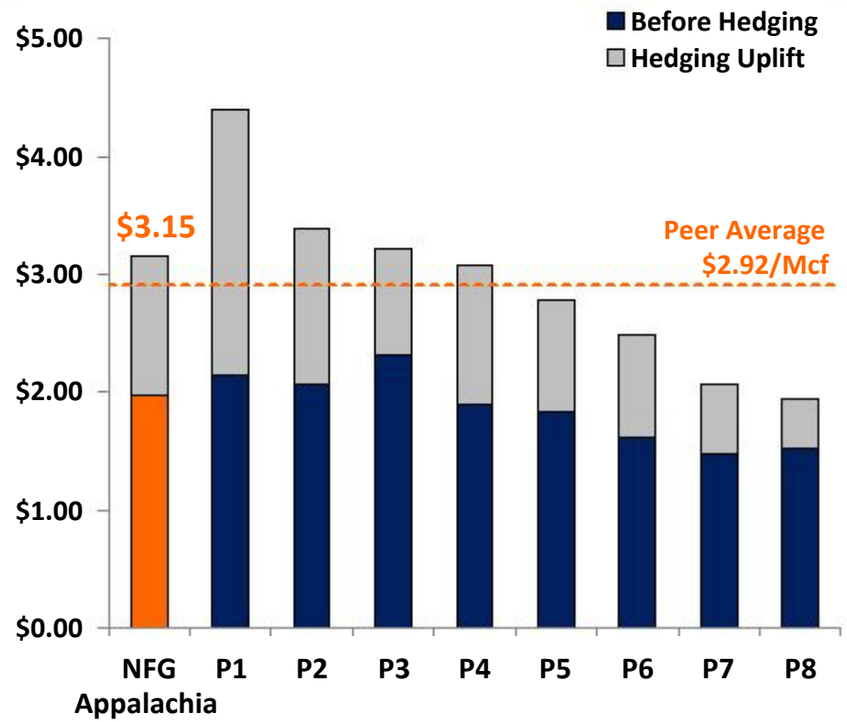
	Prospect	Product	Locations Remaining to Be Drilled	Completed Lateral Length (ft)	Average EUR (Bcf)	BTU	NYMEX / DAWN Pricing			15% IRR [1] Realized Price
							$3.00 IRR % [1]	$2.75 IRR % [1]	$2.50 IRR % [1]	
EDA	DCNR 100	Dry Gas	12	5,400	13-14	1033	59%	43%	25%	$1.57
EDA	Gamble	Dry Gas	44	4,600	11-12	1033	35%	22%	11%	$1.83
WDA	CRV	Dry Gas	60	8,800	10-11	1045	23%	17%	10%	$1.92
WDA	Hemlock / Ridgway	Dry Gas	636	8,800	8-9	1045 - 1110	16%	11%	6%	$2.14
WDA	Remaining Tier 1	Dry Gas	406	8,500	7-8	1030 - 1110	14%	10%	5%	$2.31

(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.

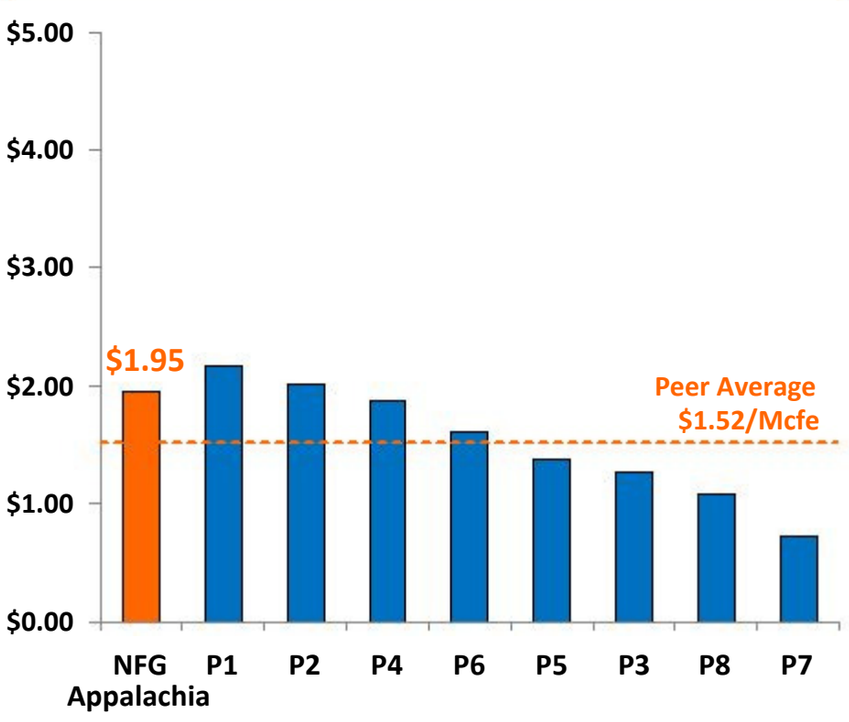
Appalachian Price Realizations & Margins

Strong hedge book, firm sales portfolio, and cost discipline generating impressive natural gas price realizations and margins in challenging commodity environment

Q1 FY16 Average Natural Gas Realizations per Mcf vs. Appalachian Peer Group(1)



Q1 FY16 Adjusted EBITDA per Mcfe vs. Appalachian Peer Group(1)



(1) Appalachian peer group includes AR, CNX, COG, EQT, GPOR, RICE, RRC & SWN. Peer group information obtained or estimated by National Fuel Gas Company from peer company quarterly public filings (press release & Form 10-K) for the quarter-ended December 31, 2015. Where applicable and when information was available, peer company realizations and margins were adjusted to reflect cash settled hedges and results of exploration and production operations only. Accounting methodology for transportation expense (included in price realizations vs. operating expense) varies between companies. NFG deducts transportation costs from revenues to calculate its price realizations.

Natural Gas Hedge Positions

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

	Fiscal 2016 (1)		Fiscal 2017		Fiscal 2018		Fiscal 2019		Fiscal 2020	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
NYMEX Swaps	18,960	$3.92	29,530	$4.20	26,070	$3.49	25,560	$3.18	16,880	$3.07
Dominion Swaps	9,420	$3.78	12,720	$3.87	-	-	-	-	-	-
MichCon Swaps	6,000	$4.10	3,000	$4.10	-	-	-	-	-	-
Dawn Swaps	8,160	$3.82	19,100	$3.70	8,400	$3.08	7,200	$3.00	7,200	$3.00
Fixed Price Physical Sales (2)	24,222	$2.55	50,660	$2.52	13,366	$2.69	6,931	$3.19	3,378	$3.25
Total	**66,762**	**$3.41**	**115,010**	**$3.34**	**47,836**	**$3.19**	**39,691**	**$3.15**	**27,458**	**$3.07**

(1) For the remaining six months of Fiscal 2016.

(2) Fixed price physical sales exclude joint development partner's share of fixed price contract WDA volumes as specified under the joint development agreement.

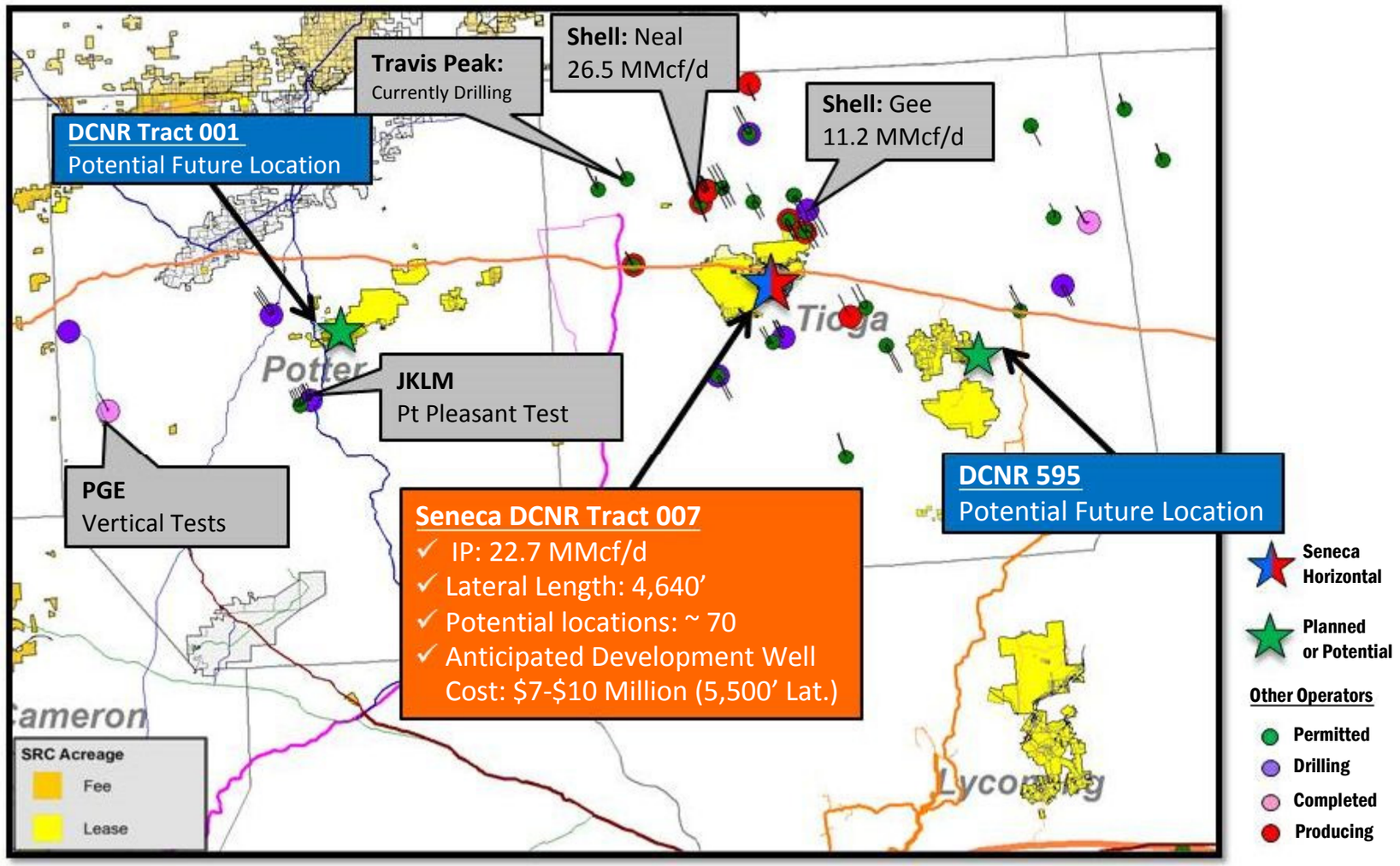
Crude Oil Hedge Positions

(Volumes & Prices in Bbl)

	Fiscal 2016 [1]		Fiscal 2017		Fiscal 2018	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
Brent Swaps	102,000	$94.06	123,000	$92.27	24,000	$91.00
NYMEX Swaps	719,000	$79.27	573,000	$71.47	51,000	$90.62
Total	**821,000**	**$81.10**	**696,000**	**$75.14**	**75,000**	**$90.74**

(1) For the remaining six months of Fiscal 2016.

Utica/Point Pleasant: EDA Opportunities



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 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.

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

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

	FY 2012	FY 2013	FY 2014	FY 2015	12-Months Ended 3/31/16
Total Adjusted EBITDA					
Exploration & Production Adjusted EBITDA	$ 397,129	$ 492,383	$ 539,472	$ 422,289	361,994
Pipeline & Storage Adjusted EBITDA	136,914	161,226	186,022	188,042	189,148
Gathering Adjusted EBITDA	14,814	29,777	64,060	68,783	66,145
Utility Adjusted EBITDA	159,986	171,669	164,643	164,037	145,754
Energy Marketing Adjusted EBITDA	5,945	6,963	10,335	12,150	9,565
Corporate & All Other Adjusted EBITDA	(10,674)	(9,920)	(11,078)	(11,900)	(10,729)
Total Adjusted EBITDA	**$ 704,114**	**$ 852,098**	**$ 953,454**	**$ 843,401**	**$ 761,877**
Total Adjusted EBITDA	**$ 704,114**	**$ 852,098**	**$ 953,454**	**$ 843,401**	**$ 761,877**
Minus: Interest Expense	(86,240)	(94,111)	(94,277)	(99,471)	(114,392)
Plus: Interest and Other Income	8,822	9,032	13,631	11,961	15,818
Minus: Income Tax Expense	(150,554)	(172,758)	(189,614)	319,136	639,812
Minus: Depreciation, Depletion & Amortization	(271,530)	(326,760)	(383,781)	(336,158)	(285,223)
Minus: Impairment of Oil and Gas Properties (E&P)	-	-	-	(1,126,257)	(1,838,803)
Plus: Reversal of Stock-Based Compensation	-	-	-	7,961	7,961
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)	-	-	-
Minus: Joint Development Agreement Professional Fees	-	-	-	-	(4,682)
Rounding	(1)	-	-	-	-
Consolidated Net Income	**$ 220,077**	**$ 260,001**	**$ 299,413**	**$ (379,427)**	**$ (817,632)**
Consolidated Debt to Total Adjusted EBITDA					
Long-Term Debt, Net of Current Portion (End of Period)	$ 1,149,000	$ 1,649,000	$ 1,649,000	$ 2,099,000	$ 2,099,000
Current Portion of Long-Term Debt (End of Period)	250,000	-	-	-	-
Notes Payable to Banks and Commercial Paper (End of Period)	171,000	-	85,600	-	-
Total Debt (End of Period)	$ 1,570,000	$ 1,649,000	$ 1,734,600	$ 2,099,000	$ 2,099,000
Long-Term Debt, Net of Current Portion (Start of Period)	899,000	1,149,000	1,649,000	1,649,000	1,649,000
Current Portion of Long-Term Debt (Start of Period)	150,000	250,000	-	-	-
Notes Payable to Banks and Commercial Paper (Start of Period)	40,000	171,000	-	85,600	157,500
Total Debt (Start of Period)	$ 1,089,000	$ 1,570,000	$ 1,649,000	$ 1,734,600	$ 1,806,500
Average Total Debt	**$ 1,329,500**	**$ 1,609,500**	**$ 1,691,800**	**$ 1,916,800**	**$ 1,952,750**
Average Total Debt to Total Adjusted EBITDA	**1.89 x**	**1.89 x**	**1.77 x**	**2.27 x**	**2.56 x**

National Fuel Gas Company

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

	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016 [1] Forecast
Capital Expenditures from Continuing Operations						
Exploration & Production Capital Expenditures	$ 648,815	$ 693,810	$ 533,129	$ 602,705	$ 557,313	$150,000-200,000
Pipeline & Storage Capital Expenditures	129,206	144,167	$ 56,144	$ 139,821	$ 230,192	$130,000-160,000
Gathering Segment Capital Expenditures	17,021	80,012	$ 54,792	$ 137,799	$ 118,166	$75,000-85,000
Utility Capital Expenditures	58,398	58,284	$ 71,970	$ 88,810	$ 94,371	$90,000-100,000
Energy Marketing, Corporate & All Other Capital Expenditures	746	1,121	$ 1,062	$ 772	$ 467	-
Total Capital Expenditures from Continuing Operations	$ 854,186	$ 977,394	$ 717,097	$ 969,907	$ 1,000,509	$445,000-545,000
Capital Expenditures from Discountinued Operations						
All Other Capital Expenditures	$ -	$ -	$ -	$ -	$ -	$ -
Plus (Minus) Accrued Capital Expenditures						
Exploration & Production FY 2015 Accrued Capital Expenditures	$ -	$ -	$ -	$ -	$ (46,173)	
Exploration & Production FY 2014 Accrued Capital Expenditures	-	-	-	(80,108)	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	-	-	-	-	-
Pipeline & Storage FY 2015 Accrued Capital Expenditures	-	-	-	-	(33,925)	
Pipeline & Storage FY 2014 Accrued Capital Expenditures	-	-	-	(28,122)	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	-	-	-	-	-
Gathering FY 2015 Accrued Capital Expenditures	-	-	-	-	(22,416)	
Gathering FY 2014 Accrued Capital Expenditures	-	-	-	(20,084)	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	-	-	-	-
Utility FY 2015 Accrued Capital Expenditures	-	-	-	-	(16,445)	
Utility FY 2014 Accrued Capital Expenditures	-	-	-	(8,315)	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	$ (39,908)	$ 57,613	$ (13,636)	$ (55,490)	$ 17,670	$ -
Eliminations	$ -	$ -	$ -	$ -	$ -	$ -
Total Capital Expenditures per Statement of Cash Flows	$ 814,278	$ 1,035,007	$ 703,461	$ 914,417	$ 1,018,179	$445,000-545,000

(1) FY2016 Exploration and Production capital expenditure guidance reflects the netting of up-front proceeds received from joint development partner for capital spent on wells drilled and/or completed prior to the execution date of the joint development agreement.

National Fuel Gas Company

Appendix

Reconciliation of Exploration & Production Adjusted EBITDA for Appalachia and West Coast divisions to Exploration & Production Segment Net Income
($ Thousands)

	Three Months Ended March 31, 2016			Twelve Months Ended March 31, 2016			Three Months Ended December 31, 2015		
	Appalachia	West Coast	Total E&P	Appalachia	West Coast	Total E&P	Appalachia	West Coast	Total E&P
Reported GAAP Earnings	**$ (189,742)**	**$ (23,593)**	**$ (213,335)**	**$ (759,150)**	**$ (221,403)**	**$ (980,553)**	**$ (215,558)**	**$ (21,528)**	**$ (237,086)**
Depreciation, Depletion and Amortization	30,775	6,499	37,274	147,030	36,592	183,622	36,565	7,468	44,033
Interest and Other Income	(14)	(13)	(27)	(14)	(2,060)	(2,074)	-	(667)	(667)
Interest Expense	13,183	363	13,546	51,269	2,225	53,494	13,772	810	14,582
Income Taxes	(138,318)	(16,975)	(155,293)	(569,570)	(163,643)	(733,213)	(154,357)	(15,498)	(169,855)
Impairment of Oil and Gas Producing Properties	344,185	53,258	397,443	1,377,186	461,617	1,838,803	378,887	56,564	435,451
Joint Development Agreement Professional Fees	-	-	-	4,682	-	4,682	4,682	-	4,682
Reversal of Stock Based Compensation	-	-	-	(825)	(1,942)	(2,767)	-	-	-
Adjusted EBITDA	**$ 60,069**	**$ 19,539**	**$ 79,608**	**$ 250,608**	**$ 111,386**	**$ 361,994**	**$ 63,991**	**$ 27,149**	**$ 91,140**

	Appalachia	West Coast	Total E&P	Appalachia	West Coast	Total E&P	Appalachia	West Coast	Total E&P
Production:									
Gas Production (MMcf)	34,113	764	34,877	129,913	3,139	133,052	32,788	783	33,571
Oil Production (MBbl)	5	718	723	26	2,982	3,008	6	742	748
Total Production (Mmcfe)	34,143	5,072	39,215	130,069	21,031	151,100	32,824	5,235	38,059
Adjusted EBITDA Margin per Mcfe	**$ 1.76**	**$ 3.85**	**$ 2.03**	**$ 1.93**	**$ 5.30**	**$ 2.40**	**$ 1.95**	**$ 5.19**	**$ 2.39**
Total Production (Mboe)	NM	845	NM	NM	3,505	NM	NM	873	NM
Adjusted EBITDA Margin per Boe	**NM**	**$ 23.12**	**NM**	**NM**	**$ 31.78**	**NM**	**NM**	**$ 31.10**	**NM**

Note: Seneca West Coast division includes Seneca corporate and eliminations.

National Fuel Gas Company

Reconciliation of Exploration & Production Segment Operating Expenses by Division
($000s unless noted otherwise)

	Twelve Months Ended September 30, 2015						Twelve Months Ended September 30, 2014					
	Appalachia	West Coast	Total E&P	Appalachia	West Coast	Total E&P	Appalachia	West Coast	Total E&P	Appalachia	West Coast	Total E&P
				$/ Mcfe	*$ / Boe*	*$ / Mcfe*				*$/ Mcfe*	*$ / Boe*	*$ / Mcfe*
Operating Expenses:												
Lease Operating & Transportation Expense - Gathering	$76,709	$0	$76,709	$0.56	$0.00	$0.49	$69,937	$0	$69,937	$0.50	$0.00	$0.44
Lease Operating Expense - Other	$34,013	$57,078	$91,091	$0.25	$16.17	$0.57	$32,811	$62,786	$95,597	$0.24	$17.74	$0.59
Total Lease Operating Expense	$110,722	$57,078	$167,800	$0.81	$16.17	$1.06	$102,748	$62,786	$165,534	$0.74	$17.74	$1.03
General & Administrative Expense	$47,445	$18,669	$66,114	$0.35	$5.29	$0.42	$45,987	$17,817	$63,804	$0.33	$5.03	$0.40
All Other Operating and Maintenance Expense	$5,296	$9,008	$14,304	$0.04	$2.55	$0.09	$6,779	$7,742	$14,521	$0.05	$2.19	$0.09
Property, Franchise and Other Taxes	$9,046	$11,121	$20,167	$0.07	$3.15	$0.13	$10,114	$10,651	$20,765	$0.07	$3.01	$0.13
Total Taxes & Other	$14,342	$20,129	$34,471	$0.11	$5.70	$0.22	$16,893	$18,393	$35,286	$0.12	$5.20	$0.22
Depreciation, Depletaion & Amortization			$239,818			$1.52			$296,210			$1.85
Production:												
Gas Production (MMcf)				136,404	3,159	139,563				139,097	3,210	142,307
Oil Production (MBbl)				30	3,004	3,034				31	3,005	3,036
Total Production (Mmcfe)				136,584	21,183	157,767				139,283	21,240	160,523
Total Production (Mboe)				22,764	3,531	26,295				23,214	3,540	26,754

Note: Seneca West Coast division includes Seneca corporate and eliminations.