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): May 3, 2018

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))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 7.01 Regulation FD Disclosure.

On May 3, 2018, 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: 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; 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 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; changes in the price of natural gas or oil; impairments under the SEC's

full cost ceiling test for natural gas and oil reserves; 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; 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; increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; 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 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; 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; the impact of potential information technology, cybersecurity or data security breaches; economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities or acts of war; significant differences between the Company's projected and actual capital expenditures and operating expenses; 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 May 2018

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/ Sarah J. Mugel
Sarah J. Mugel
Assistant Secretary

Dated: May 3, 2018

Exhibit 99

National Fuel®

Investor Presentation

Q2 Fiscal 2018 Update

May 3, 2018

Safe Harbor For Forward Looking Statements

National Fuel

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 could cause actual results to differ materially from those discussed in the forward-looking statements: 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; 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 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; changes in the price of natural gas or oil; impairments under the SEC's full cost ceiling test for natural gas and oil reserves; 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; 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; increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; 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 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; 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; the impact of potential information technology, cybersecurity or data security breaches; economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities or acts of war; significant differences between the Company's projected and actual capital expenditures and operating expenses; 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, 2017 and the Forms 10-Q for the quarter ended December 31, 2017 and March 31, 2018. 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.

NFG: A Diversified, Integrated Natural Gas Company

National Fuel

Upstream
E&P

Developing our large, high quality acreage position in Marcellus & Utica shales

785,000 Net acres in Appalachia

~460 MMcf /day Net Appalachian natural gas production

Midstream
Gathering Pipeline & Storage

Expanding and modernizing pipeline infrastructure to provide access to Appalachian supplies

$1.4 Billion Investments since 2010

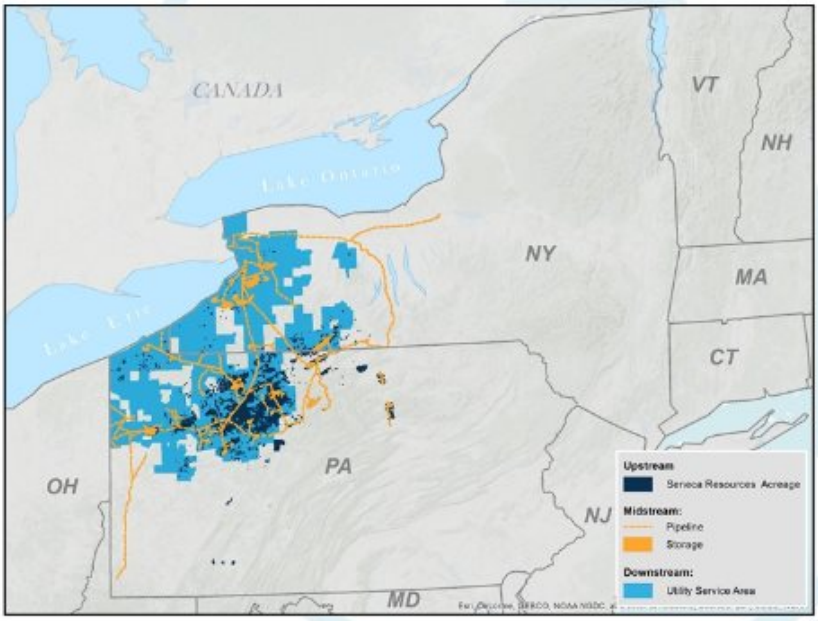
4.1 MMDth Daily interstate pipeline capacity under contract

Downstream
Utility Energy Marketing

Providing safe, reliable and affordable service to customers in WNY and NW Pa.

743,500 Utility Customers

133 Bcf Utility system natural gas throughput in FY17



Why National Fuel?

National Fuel

Strategy For Creating Long-term, Sustainable Shareholder Value

1 Unique Integration and Diversified Asset Mix Serves as Foundation for Growth Strategy

- ✓ Geographic and operational integration lowers costs and drives financial efficiencies
- ✓ Significant base of stable, regulated earnings and cash flows supports dividend and helps to lower our cost of capital
- ✓ 100% ownership of midstream assets (no MLP structure) preserves capital flexibility and better aligns corporate strategic goals

2 Opportunity for Considerable Upstream and Midstream Growth in Appalachia

- ✓ Large, contiguous footprint in Appalachia drives peer leading low-cost development
- ✓ Fee-ownership (no royalty) on majority of acreage a significant competitive advantage
- ✓ Stacked Marcellus and Utica development / reutilization of gathering infrastructure improves drilling economics and enhances consolidated returns
- ✓ Positioned to expand / modernize pipeline systems to accommodate regional supply growth

3 Long-term, Disciplined Approach to Capital Allocation and Returns

- ✓ Long-term capital plans designed to grow earnings for each business segment, live within cash flows and achieve value-added returns on capital employed
- ✓ Production and gathering growth underpinned by long-term sales contracts and hedges
- ✓ Strong balance sheet provides financial flexibility
- ✓ 47-year track record of growing the dividend

Benefits of Integration

National Fuel

Unique Geographic and Operational Integration Drives Synergies that Maximize Shareholder Value

Utility and Pipeline & Storage Operational Efficiencies

Rate-regulated entities reduce operating expenses by sharing common:

- Management
- Engineering
- Field labor
- Facilities
- Back office
- Gas dispatch center
- Warehouse
- IT systems
- Vehicles
- Tools & equipment

Upstream and Midstream Strategic Development

Coordinated development in Appalachia drives long-term growth and enhances consolidated returns:

- Co-development of Marcellus and Utica
- Installing just-in-time gathering infrastructure
- Expanding pipeline transmission infrastructure to reach demand markets

Commercial Relationships

Utility and Energy Marketing segments are significant Pipeline & Storage customers:

29% of contracted firm transport capacity

43% of contracted firm storage capacity

Financial Efficiencies

- Investment grade credit rating
- Shared borrowing capacity
- Consolidated income tax return
- Balanced earnings and diversified cash flows support dividend

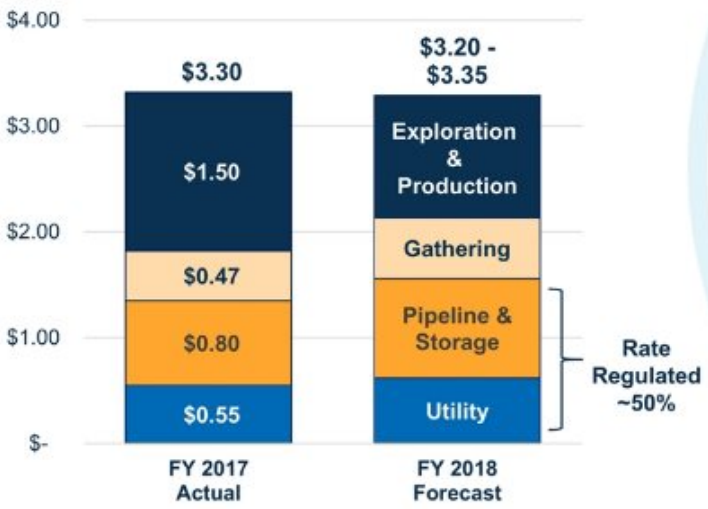
Benefits of NFG Integrated Model

- ✓ Large Appalachian footprint with considerable opportunity for growth
- ✓ Operational scale
- ✓ Lower cost of capital
- ✓ Lower operating costs
- ✓ More efficient capital investment
- ✓ More competitive pipeline infrastructure projects
- ✓ Higher returns on investment
- ✓ Strong balance sheet
- ✓ Growing, stable dividend

Diversified, Balanced Earnings and Cash Flows

National Fuel

Adjusted Operating Results ($ per share)[1]



Adjusted EBITDA ($ millions)[2]

(1) A reconciliation of Adjusted Operating Results to Earnings per Share as presented on the Consolidated Statement of Income and Earnings Reinvested in the Business is included at the end of this presentation
(2) A reconciliation of 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

Near Term Growth Strategy

National Fuel

Exploration & Production Gathering

- ✓ 3 rig program designed to grow Marcellus and Utica production and gathering throughput at a 15-20% CAGR over next 5 years
- ✓ Utilize significant existing gathering infrastructure to support further WDA development and increase returns
- ✓ Maintain focus on living within cash flows

Pipeline and Storage

- ✓ Pursue and execute opportunities for system expansion:
  - FM100 Project
  - Empire North Project
  - Line N Expansions
  - Northern Access
- ✓ Invest in modernization of Supply Corp. system, which will result in rate base growth

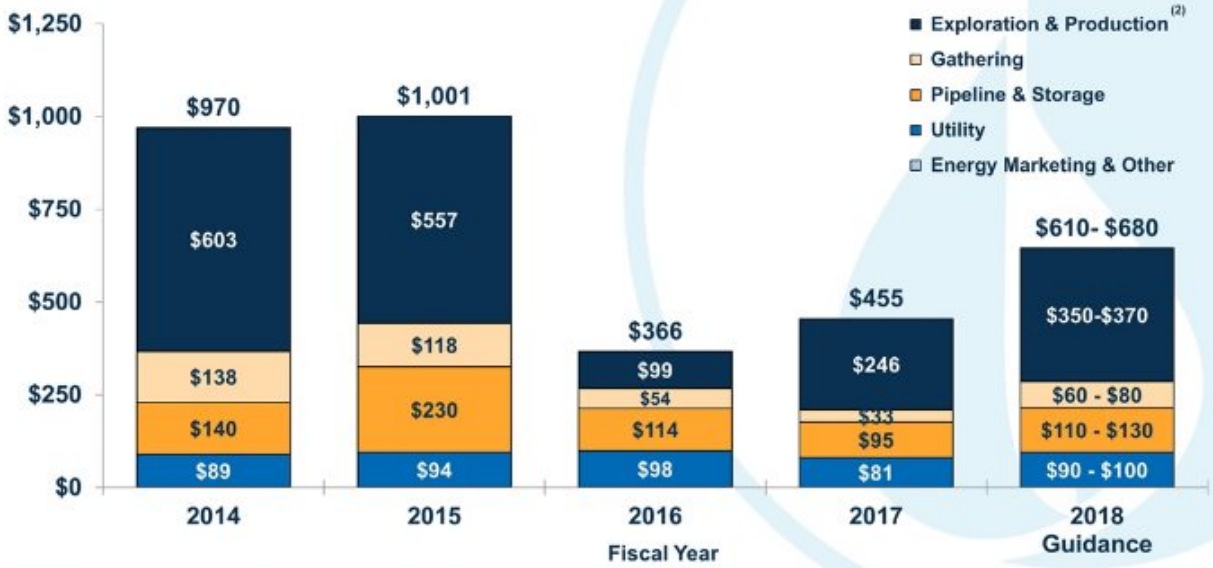
Utility

- ✓ Continue to invest in pipeline replacement and modernization:
  - Improve system safety and reliability
  - Seek timely recovery through tracker mechanism in New York
- ✓ Maintain focus on O&M spending levels

Disciplined, Flexible Capital Allocation

National Fuel

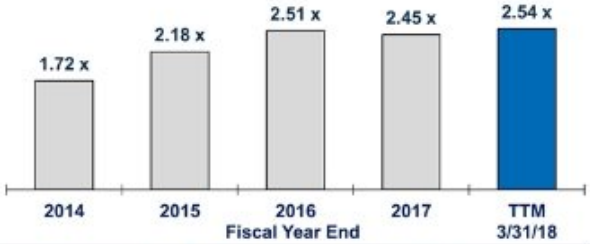
Capital Expenditures by Segment ($ millions)[1]



(1) A reconciliation to Capital Expenditures as presented on the Consolidated Statement of Cash Flows is included at the end of this presentation.
(2) FY16, FY17, and FY18 guidance reflects the netting of $157 million, $7 million, and $17 million, respectively, of up-front proceeds received from joint development partner for working interest in joint development wells.

Maintaining Strong Balance Sheet & Liquidity

Net Debt / Adjusted EBITDA[1]



Capitalization

$4.0 Billion Total Capitalization as of March 31, 2018

Debt Maturity Profile ($MM)

Liquidity

Committed Credit Facilities	$ 750 MM
Short-term Debt Outstanding	0 MM
Available Short-term Credit Facilities	750 MM
Cash Balance at 3/31/18	228 MM
Total Liquidity at 3/31/18	**$ 978 MM**

(1) Net Debt is net of cash and temporary cash investments. Reconciliations of Net Debt and Adjusted EBITDA to Net Income are included at the end of this presentation.

Dividend Track Record

National Fuel

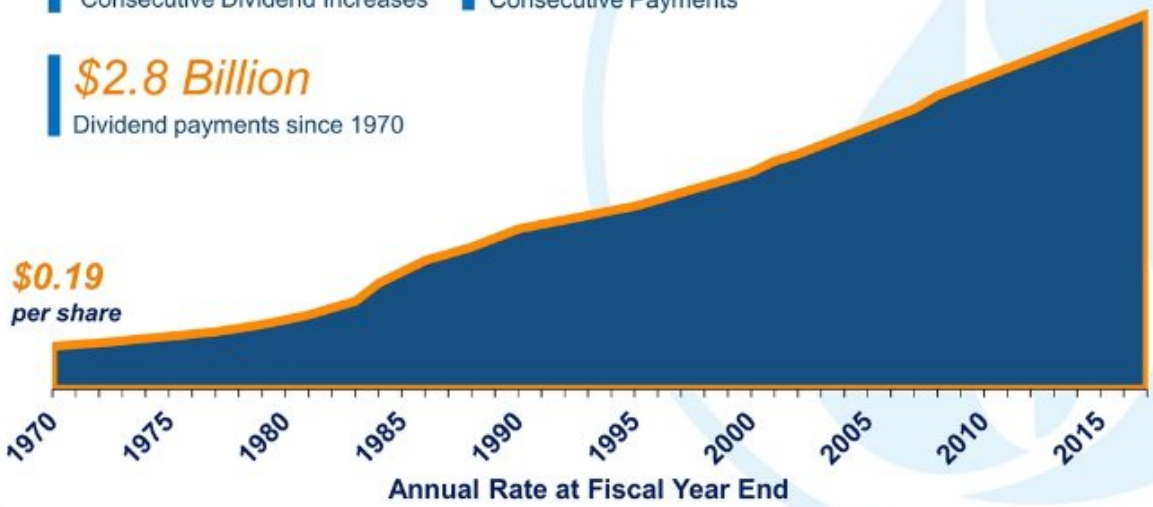
47 Years
Consecutive Dividend Increases

115 Years
Consecutive Payments

$1.66
per share

3.2%
yield[1]

$2.8 Billion
Dividend payments since 1970



(1) As of May 1, 2018.

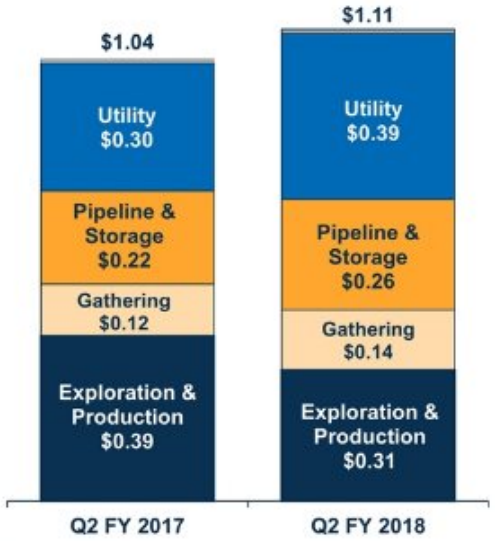
Q2 Fiscal 2018

Financial Highlights and Operational Update

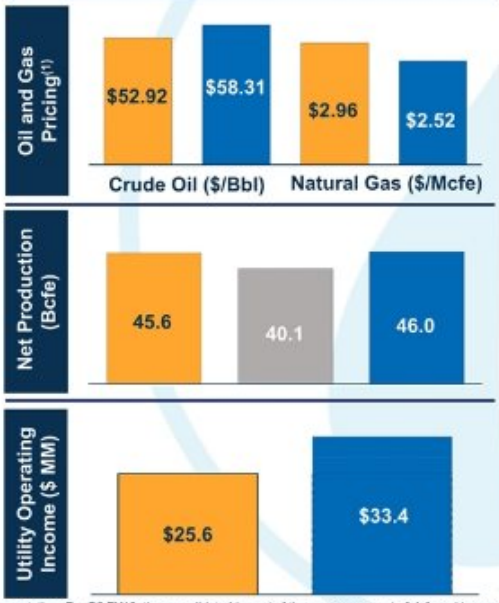
Second Quarter Fiscal 2018 Results and Drivers

National Fuel

Adjusted Operating Results ($/share)[2]



■ Q2 FY 2017 ■ Q1 FY 2018 ■ Q2 FY 2018



Drivers

- Oil Prices
- Natural Gas Prices
- New Lycoming Pad Brought Online
- No Curtailments
- Colder Weather in PA
- NY Rate Case
- Lower O&M Expense

(1) Realized price after hedging
(2) Reconciliation of Adjusted Operating Results to Earnings Per Share is included in the Appendix of this presentation. For Q2 FY18, the consolidated impact of the remeasurement of deferred income taxes was $(0.05) under 2017 Tax Reform – $(0.01) for the Exploration and Production Segment, $(0.01) for the Gathering Segment, and $(0.03) for the Corporate and All Other Segment.

Upstream & Midstream Business Operations Update

New Transco / Supply Corp. Expansion Project

- Will provide Seneca with ~300,000 Dth/day of incremental firm transportation capacity out of the basin to premium markets
- Significant incremental revenues expected for Supply Corp. and Gathering segment
- Company also remains committed to the federally-approved Northern Access Project, for which legal challenges at Second Circuit and FERC remain pending

Seneca to add 3rd drilling rig in third quarter fiscal 2018

- Primarily dedicated to redevelopment of Seneca's WDA (Clermont-Rich Valley) acreage for the Utica Shale
- 15-20% net Appalachian natural gas production and gathering throughput CAGR expected through 2022.
- Seneca and Gathering expect to live within cash flows over next 3 years at current strip pricing

Seneca Sale of Sespe Assets

- Sale effective date: October 1, 2017
- Sale value: $43 million, with no gain recognized (under full cost accounting)[1]
- 900 BOE/day reduction in California production for remainder of Fiscal 2018
- Expected to reduce remaining FY 18 earnings by $0.05 per share

(1) Net proceeds are expected to be ~$37 million to reflect the value of production from the 10/1/17 sale date to the 5/1/18 close date

New Pipeline Expansion Provides Consolidated Benefit

National Fuel

Project expected to provide long term earnings uplift to Seneca, Supply Corp. and Gathering

300,000 Dth/d of new transportation capacity from WDA and EDA acreage positions to premium markets

Seneca

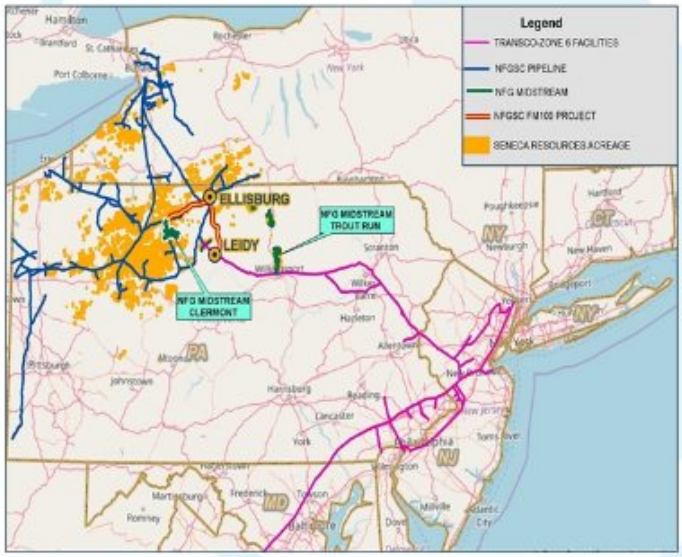
- ✓ **New Transco pipeline capacity:** ~ 300,000 Dth/day
- ✓ **Rate:** expected to be competitive with other expansion project rates in Seneca's current transportation portfolio
- ✓ **Delivery Point(s):** Transco Zone 6 interconnections

Supply Corp.

- ✓ **Expansion of pending FM100 Modernization Project**
- ✓ **Lease to Transco of new capacity:** ~300,000 Dth/day
- ✓ **Est. capital cost:** $250-300 million[1]
- ✓ **Est. in-service date:** late calendar year 2021

Gathering

- ✓ **All incremental Seneca volumes will flow through NFG gathering facilities**



(1) Includes expansion and modernization portions of the Project

Impact of Federal Tax Reform

National Fuel

Non-Rate Regulated Segments

Exploration & Production and Gathering

- Positive ongoing earnings impact expected from reduction in federal income tax rate from 35% to 21% (blended 24.5% in FY 2018)
- Remeasurement of deferred income taxes resulted in $111.0 million earnings benefit recorded as of the close of Q2 FY 2018.

Rate Regulated Segments

Pipeline & Storage

- Evaluating FERC's 3/15/18 notice of proposed rulemaking and related FERC actions concerning Federal tax reform
- Expect any adjustment to rates to be prospective – no refund provision recorded
- Recorded remeasurement of deferred income tax balance sheet amounts as regulatory liability

Utility

- Evaluating NY PSC 12/29/17 and PA PUC 3/15/18 orders instituting proceedings on tax reform
- Expect any adjustment to rates to be retroactive - recorded $6.0 million ($4.4 million after-tax) refund provision in Q1 FY18 and $5.3 million ($3.9 million after-tax) provision in Q2 FY18
- Recorded remeasurement of deferred income tax balance sheet amounts as regulatory liability

NFG Consolidated

Higher earnings / Lower effective tax rate: 26%-27% in FY 18 and ~25% FY19+

Impact on cash flow is expected to be positive over long-term

Fiscal 2018 Earnings Guidance

National Fuel

	FY 2017 Earnings	FY2018 Earnings Guidance[1]
	$3.30 /share	$3.20 to $3.35 /share

Key Guidance Drivers		
Non-regulated Businesses *Exploration & Production* *Gathering*	↑ Production & Gathering Throughput	▪ Seneca Net Production: 175 to 190 Bcfe ▪ Gathering Revenues: $110 to $115 million
	↓ Realized natural gas prices (after-hedge)	▪ Natural Gas: ~$2.50 /Mcf[2] *(vs. $2.95 /Mcf in FY17)*
	↑ Realized oil prices (after-hedge)	▪ Crude Oil: ~$58 /Bbl[3] *(vs. $53.87 /Mcf in FY17)*
Regulated Businesses *Pipeline & Storage* *Utility*	↔ Pipeline & Storage Revenues	▪ ~$295 million in revenues *(flat vs. FY17)*
	↑ Utility Normal Weather	▪ Warmer than normal weather impacted FY17 utility earnings by ~$0.06 /share
Tax Reform	↑ Lower effective tax rate	▪ Effective tax rate 26% to 27% (federal rate 24.5%) ▪ Earnings neutral for Utility segment – tax savings offset by regulatory refund provision (~$16 million pre-tax)

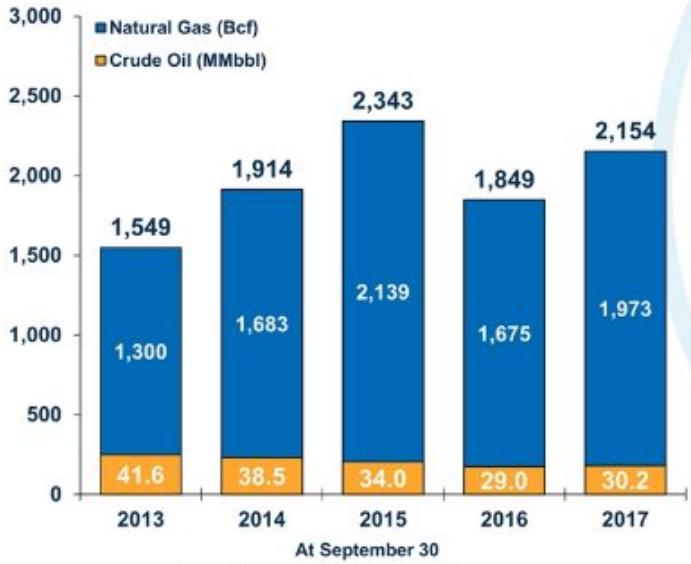
(1) Excludes the $107.0 million, or $1.24 per share, reduction in tax expense due to the remeasurement of deferred taxes resulting from the 2017 Tax Reform Act. See non-GAAP disclosure on slide #57.
(2) Assumes NYMEX natural gas pricing of $2.75 /MMBtu and basin spot pricing of $2.00 /Mmbtu for remainder of FY18 and reflects the impact of existing financial hedge, firm sales and firm transportation contracts.
(3) Assumes NYMEX (WTI) oil pricing of $65.00 /Bbl and California-MWSS pricing differentials of 98% to WTI for the remainder of FY18, and reflects impact of existing financial hedge contracts.

Exploration & Production and Gathering Overview

Seneca Resources Corporation ~ National Fuel Gas Midstream Corporation

Proved Reserves

Total Proved Reserves (Bcfe)



3-Year Average F&D Cost ($/Mcfe)

Fiscal 2017 Proved Reserves Stats

- 225% Reserve Replacement Rate (adjusted for revisions)
- Seneca Drill-bit F&D = $0.60/Mcfe[1]
- Appalachia Drill-bit F&D = $0.51/Mcfe[1]

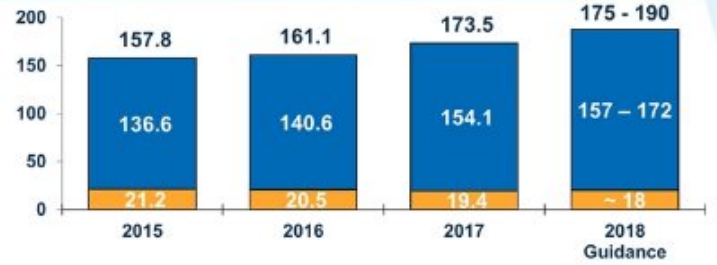
(1) Seneca "Drill-bit" finding and development ("F&D") costs exclude the impact of reserve revisions.

Growing Production within Disciplined Capital Program

National Fuel

E&P Net Capital Expenditures[1] ($ millions)

E&P Net Production (Bcfe)



Seneca's Near-term Operational Plan

Appalachia Natural Gas

- ✓ Move to 3-rig drilling program, with new rig in the WDA focused on redevelopment of Clermont-Rich Valley acreage for Utica
- ✓ Target 15-20%+ production CAGR over next 5 years
- ✓ Resumed development on prolific Marcellus acreage in Lycoming County, Pa. (new pad brought to sales in Q2 2018)
- ✓ Returned to developing 100% NRI wells in the WDA (last JDA pad brought on-line in Q2 FY18)
- ✓ Continue Utica development in WDA and EDA in FY18
- ✓ Continue to layer-in firm sales to reduce spot market risk and take advantage of attractive regional pricing

California Oil

- ✓ Minimal capital investment to generate flat to modest growth over next 3 years
- ✓ Development focus on new farm-in acreage in Midway Sunset
- ✓ Low cost structure helps generate significant positive cash flows at $60+ /bbl

(1) A reconciliation to Capital Expenditures as presented on the Consolidated Statement of Cash Flows is included at the end of this presentation. FY16, FY17, and FY18 guidance reflects the netting of $157 million, $7 million, and $17 million, respectively, of up-front proceeds received from joint development partner for working interest in joint development wells.

Significant Appalachian Acreage Position

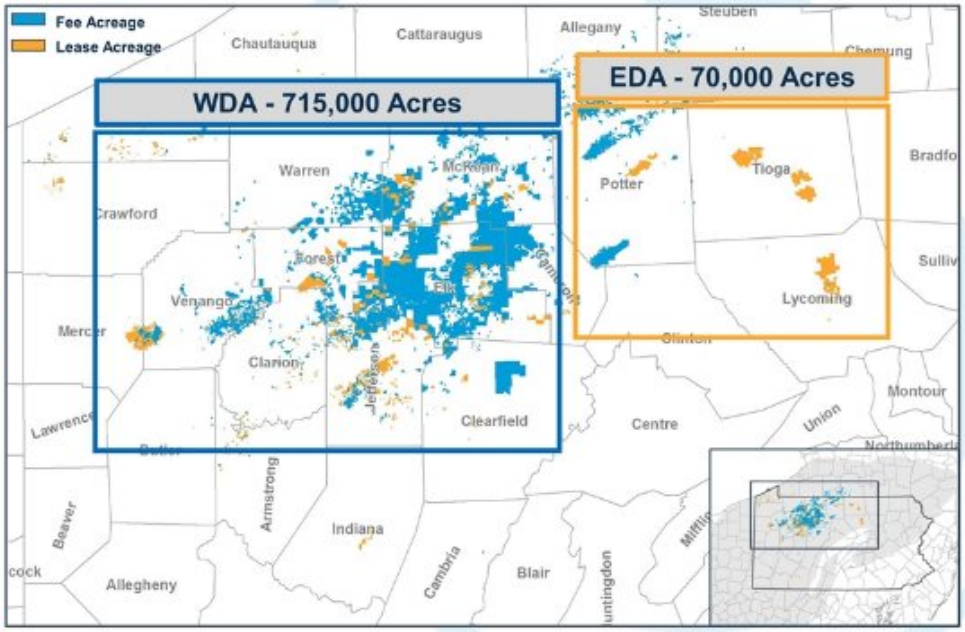
National Fuel

Western Development Area (WDA)

- Current gross production: ~320 MMcf/d
- Large inventory of high quality Marcellus & Utica acreage economic at ~$2.00/Mcf
- Royalty free mineral ownership enhances well economics
- Highly contiguous nature drives cost and operational efficiencies

Eastern Development Area (EDA)

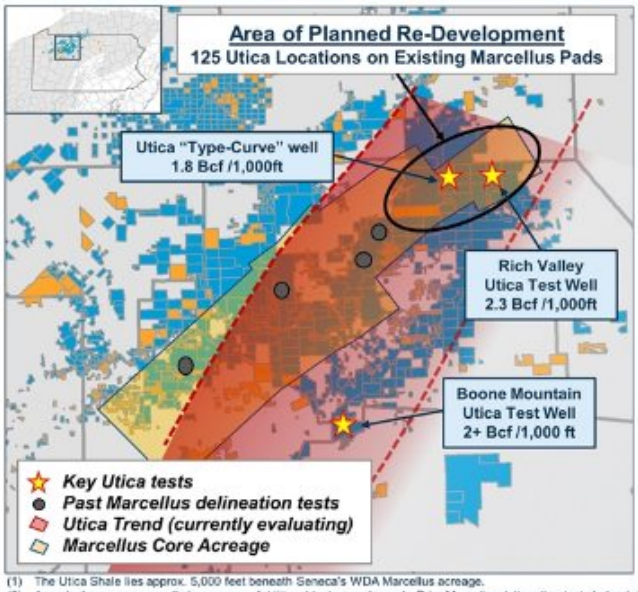
- Current gross production: ~295 MMcf/d
- Mostly leased (16-18% royalty) with no significant near-term lease expirations
- 100+ remaining Marcellus & Utica locations economic under ~$1.90/Mcf
- Additional Utica & Geneseo potential across position



Western Development Area

National Fuel

Marcellus Core Acreage vs. Utica Appraisal Trend(1)



- ✓ **Significant multi-zone drilling inventory economic at ~$2.00 /Mcf**
  - Marcellus Shale : ~632 well locations remaining / 200,000 acres
  - Utica Shale: 500+ well locations / evaluating extent of prospective acreage (2)
- ✓ **Fee acreage / existing infrastructure enhances economics**
  - No royalty or lease expirations on most acreage
  - Expected Utica development will utilize existing upstream and midstream infrastructure to maximize ROI
- ✓ **Highly contiguous position drives best in class well costs**
  - Multi-well pad drilling with laterals approaching 10,000 ft.
  - Water management operations keep water costs low
- ✓ **Long-term firm contracts support growth and returns**

	EUR Bcf/1000'	Well Cost $M/1000'	IRR(3) % $2.50	Break-even 15% IRR
WDA - Utica	1.7	$921	29%	$1.96
WDA - Marcellu	1.1	$648	26%	$2.09

(1) The Utica Shale lies approx. 5,000 feet beneath Seneca's WDA Marcellus acreage.
(2) Appraisal program currently in progress. Additional tests are planned. Prior Marcellus delineation tests helped define the prospective limits of the Marcellus core acreage; planned testing in the Utica expected to do the same.
(3) Internal Rate of Return (IRR) is pre-tax and includes estimated well costs under current cost structure, LOE, and anticipated Gathering tariffs.

WDA Utica Appraisal Results and Initial Type Curve

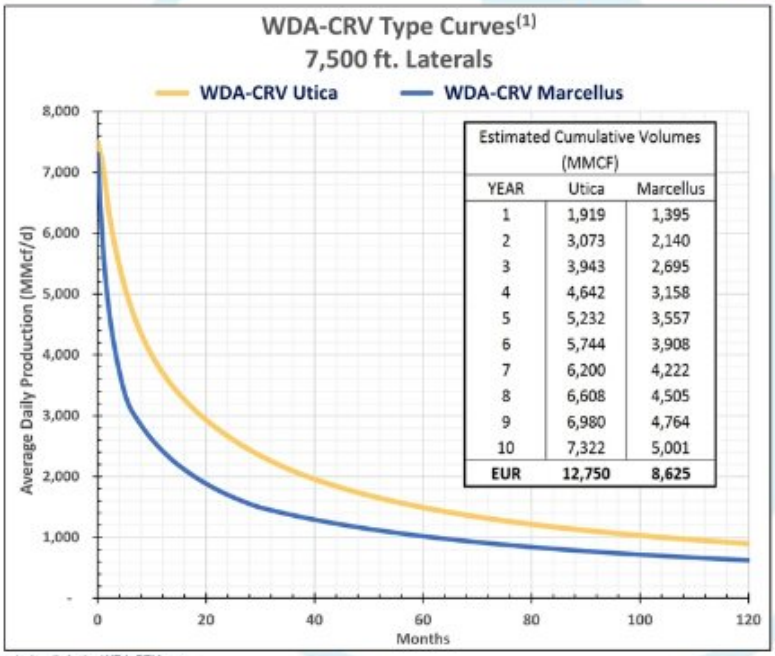
National Fuel

WDA Utica Appraisal Update

- ✓ Tested / producing from 9 Utica wells in WDA-CRV
- ✓ Higher pressure significantly enhances well productivity (Utica ~5,000' deeper than Marcellus)
- ✓ Drawdown management is critical: restricted drawdown improves well EURs
- ✓ Early production declines much shallower vs. Marcellus

WDA Utica Test Well Results

	"Type Curve" Well	Best Well
Pad	D09-NF-A	C09-D
Well	196HU	214HU
Lateral Length	6,300	5,530
Est. EUR /1,000 ft	1.8 Bcf	2.3 Bcf
Production Results (MMcf/1,000ft per day):		
7-day IP	1.0	1.5
30-day IP	1.0	1.4
60-day IP	0.9	1.3
90-day IP	0.9	1.3



Estimated Cumulative Volumes (MMCF)		
YEAR	Utica	Marcellus
1	1,919	1,395
2	3,073	2,140
3	3,943	2,695
4	4,642	3,158
5	5,232	3,557
6	5,744	3,908
7	6,200	4,222
8	6,608	4,505
9	6,980	4,764
10	7,322	5,001
EUR	**12,750**	**8,625**

(1) Initial WDA-CRV Utica type curve based on production results and reservoir expectations from the first 5 appraisal wells in the WDA-CRV area.

Transitioning to Utica Development in CRV

National Fuel

WDA Utica Development Will Utilize Existing Pad, Water, and Gathering Infrastructure to Drive Economics

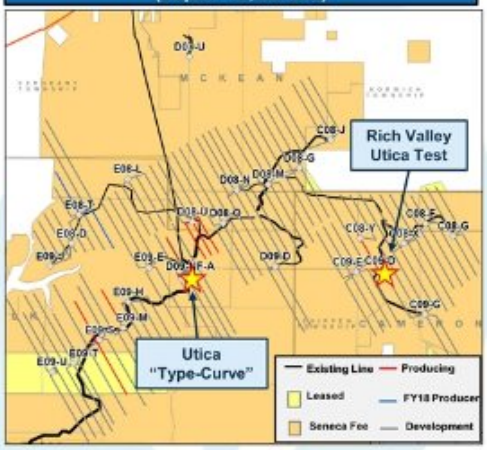
WDA Utica Transition Plan

1) **Finish Marcellus Pads in Development**
   - Drill 22 / complete 39 Marcellus wells (100% Seneca)
   - Completed and producing 75 of 75 joint development wells
2) **Optimize Utica D&C design**
   - Drill 12 Utica wells off Marcellus pads
   - Optimization to include:
     - Well spacing
     - Completion design / stage spacing
     - Landing zone targets
3) **Transition to Utica development by FY19**
   - Continue shift toward multi-well Utica pads
   - Tailor development plan to reuse existing pad, water and gathering infrastructure

WDA-CRV Marcellus
(Depth ~7,000 feet)

- ✓ Average production: 264 Mcf/d
- ✓ Rem. Avg. EUR 1.0-1.1 Bcf / 1,000 lat ft.
- ✓ Rem. Avg. Well Costs = $648/lat ft.

WDA-CRV Utica
(Depth ~12,000 feet)



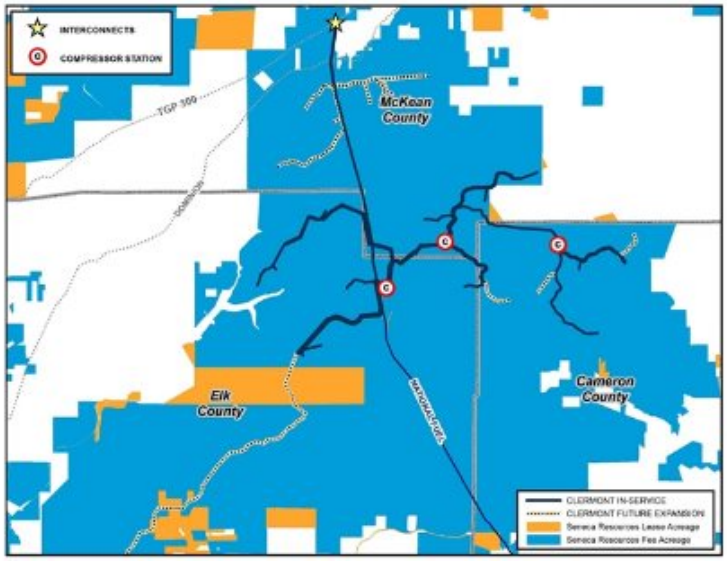
- ✓ 125+ locations on existing Marcellus pads
- ✓ Est. EURs 1.7 Bcf / 1,000 lat ft.
- ✓ Est. Development Well Costs = $921/lat ft.

Integrated Development – WDA Gathering System

National Fuel

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

Clermont Gathering System Map



Current System In-Service

- ~70 miles of pipe / 36,220 HP of compression
- Current Capacity: 470 MMcf per day
- Interconnects with TGP 300
- Total Investment to Date: $290 million

Future Build-Out

- FY 2018 CapEx: $10 MM - $15MM
- Modest gathering pipeline and compression investment required to support Seneca's transition to development and increased rig count
- 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

WDA Firm Transportation and Sales Capacity

National Fuel

WDA Exit Capacity Supports Long-term Production Growth and Protects Consolidated Returns

WDA Gas Marketing Strategy

- ✓ Seneca's net production will utilize more of its gross capacity through time as JDA production declines
- ✓ Will continue to layer-in firm sales deals of short and longer duration on TGP 300 to reduce spot exposure
- ✓ WDA spot realizations track TGP Station 313 pricing, typically 10¢ - 30¢ better than TGP Marcellus Zone 4
- ✓ Favorable resolution to Northern Access would provide additional capacity as soon as fiscal 2021

WDA Contracted Firm Transport and Sales Volumes (gross)

Eastern Development Area

National Fuel

EDA Highlights

1 DCNR Tract 007 (Tioga Co., Pa)

- 1 Utica and 1 Marcellus producing well
- Utica 30-day IP = 15.8 MMcf/d
- Utica development expected to begin in fiscal 2018
- ~48 remaining Utica locations economic at ~$1.83 /Mcf

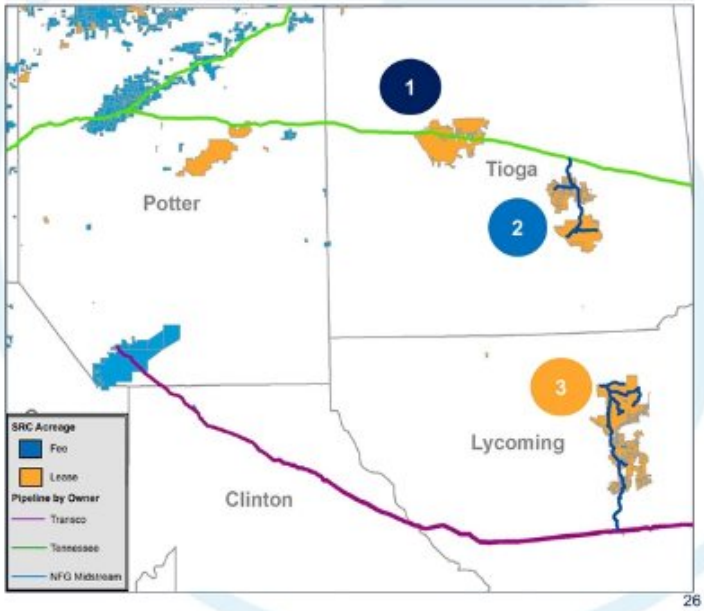
2 Covington & DCNR Tract 595 (Tioga Co., Pa.)

- Gross daily production: ~105 MMcf/d
- Marcellus locations fully developed
- Opportunity for future Utica appraisal

3 DCNR Tract 100 & Gamble (Lycoming Co., Pa.)

- Gross daily production: ~190 MMcf/d
- 51 remaining Marcellus locations economic at ~$1.54 /Mcf
- Atlantic Sunrise capacity (190 MDth/d) by close of fiscal 2018
- Geneseo shale to provide 100-120 additional locations

EDA Acreage – 70,000 Acres

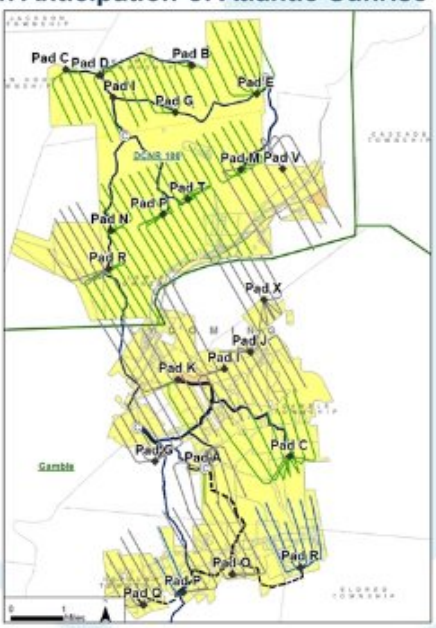


EDA Marcellus: Lycoming County Development

National Fuel

Marcellus Development in Lycoming County has Resumed in Anticipation of Atlantic Sunrise

- ✓ **Prolific Marcellus acreage with peer leading well results**
  - Average Marcellus IP rate of17.0 MMcf/d
  - 51 remaining Marcellus locations economic at ~$1.54 /Mcf
- ✓ **Near-term development focused on filling Atlantic Sunrise capacity now forecasted to be available in mid-August 2018**



(1) Includes physical fixed price and NYMEX-based firm sales contracts that do not carry any additional transportation costs.

EDA Utica: Tioga County Development

National Fuel

Utica Development in Tioga County – Tract 007 Expected to Begin in 2H FY18

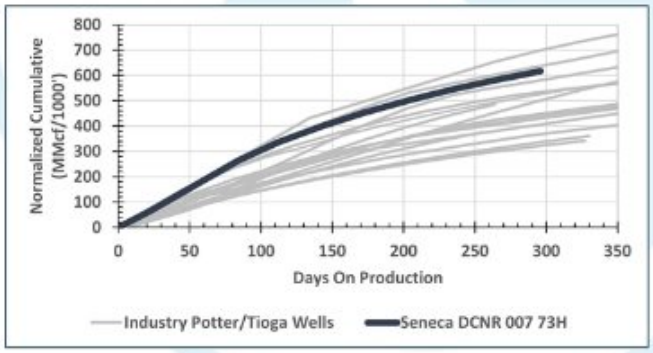
- ✓ **Inventory:** 48 locations economic at ~$1.83 /Mcf
  - Targeting to grow production by 100 to 150 MDth/d by FY20
- ✓ **Expected Development Costs:** $1,045 per lateral ft.
- ✓ **Gathering Infrastructure:** NFG Midstream Wellsboro
  - Modest build-out required to connect to TGP 300
- ✓ **Sales/Takeaway Strategy:** Layer-in firm sales with shippers holding capacity on TGP 300

EDA – TGP 300 Firm Contracts

(1) Includes physical fixed price and NYMEX-based firm sales contracts that do not carry any additional transportation costs.

Tract 007 Utica Appraisal Well Results vs. Industry

In-Service	November 2016
Lateral Length	4,640 ft
30 Day IP /1,000 ft	3.4 MMcf/d
Est. EUR /1,000 ft	2.4 Bcf



Integrated Development – EDA Gathering Systems

National Fuel

Gathering Segment Supporting Seneca's EDA Production & Future Development

Wellsboro Gathering System

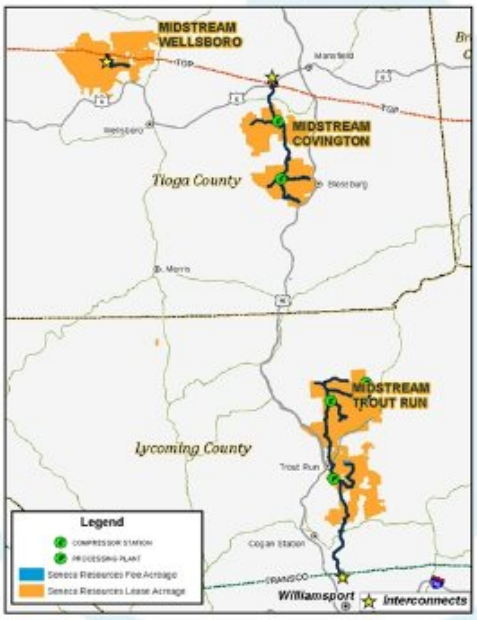
- **Total Investment (to date):** $7 million
- **FY 2018 Capital Expenditures:** $8MM - $12MM
- **Capacity:** 200,000 Dth per day (Interconnect w/ TGP 300)
- **Production Source:** Seneca Resources – Tioga Co. (DCNR Tract 007)

Covington Gathering System

- **Total Investment (to date):** $45 million
- **FY 2018 Capital Expenditures:** $13MM - $15MM
- **Capacity:** 220,000 Dth per day (Interconnect w/ TGP 300)
- **Production Source**: Seneca Resources – Tioga Co. (Covington and DCNR Tract 595)

Trout Run Gathering System

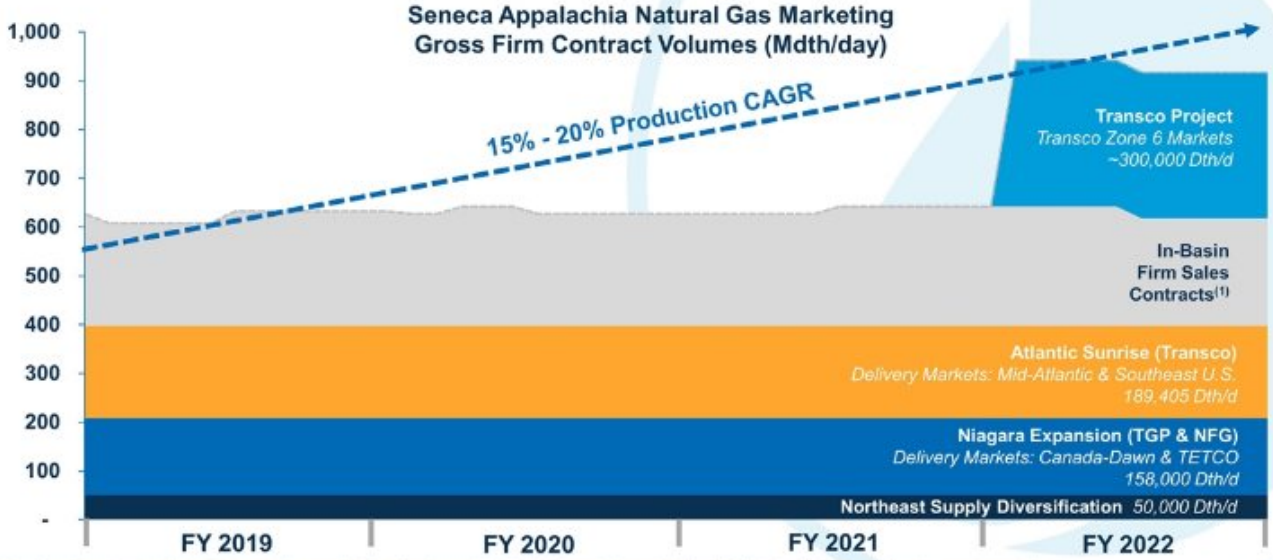
- **Total Investment (to date):** $189 million
- **FY 2018 Capital Expenditures:** $30 MM - $45 MM
- **Capacity:** 466,000 to 585,000 Dth per day (Interconnect w/ Transco)
- **Production Source:** Seneca Resources – Lycoming Co. (DCNR Tract 100 and Gamble)
- Future third-party volume opportunities



Long-term Contracts Supporting Appalachian Growth

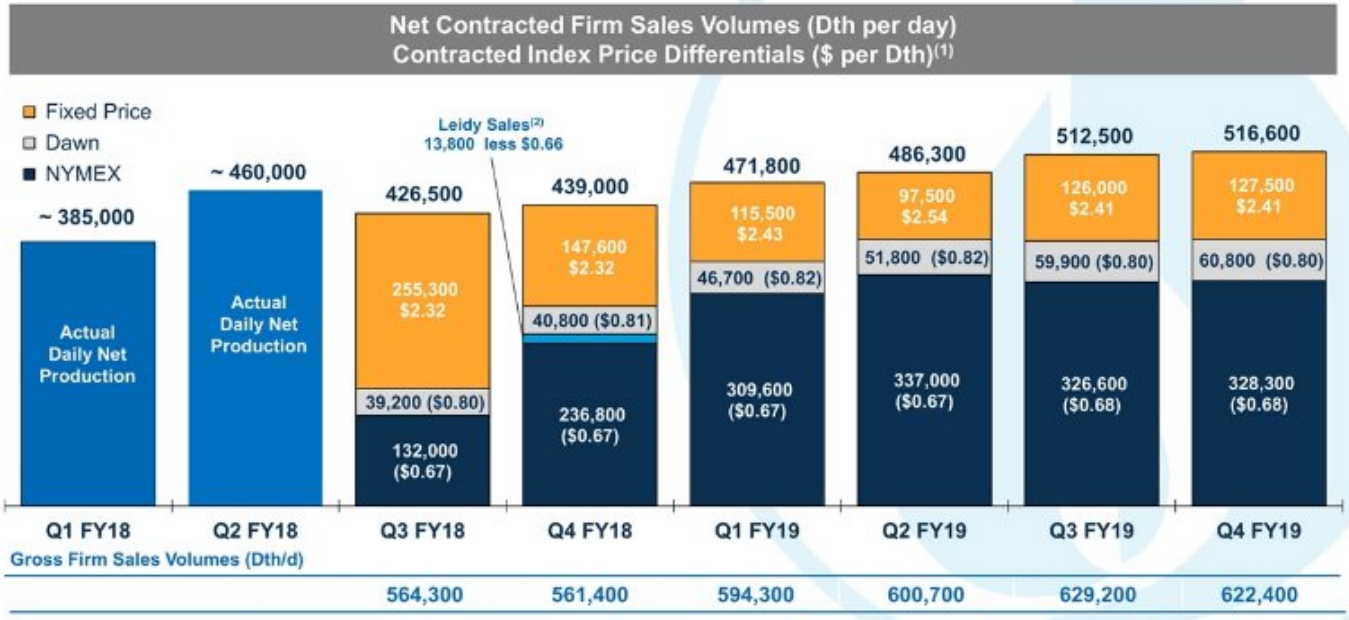
National Fuel

Seneca continues to layer-in firm sales contracts with attractive realizations at regional pricing points to lock-in drilling economics and minimize spot exposure as it waits for new capacity out of the basin



(1) Represents 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.

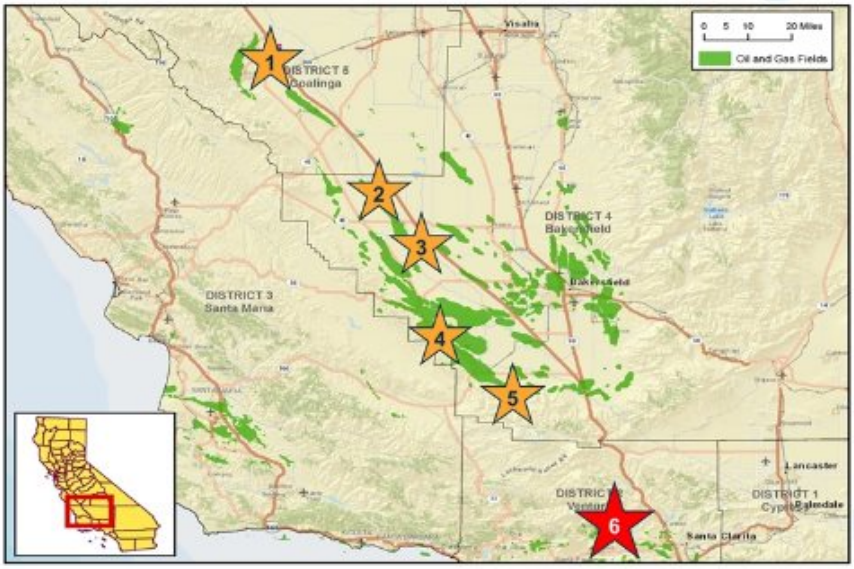
Near-term Firm Sales Provide Market & Price Certainty



(1) Values shown represent the weighted average fixed price or contracted fixed differential relative to NYMEX (netback price) less any associated transportation costs.
(2) Represents one month (July 2018) of 50,000 Dth/d firm sales at Leidy Hub resulting from the anticipated delay of Atlantic Sunrise.

California Oil

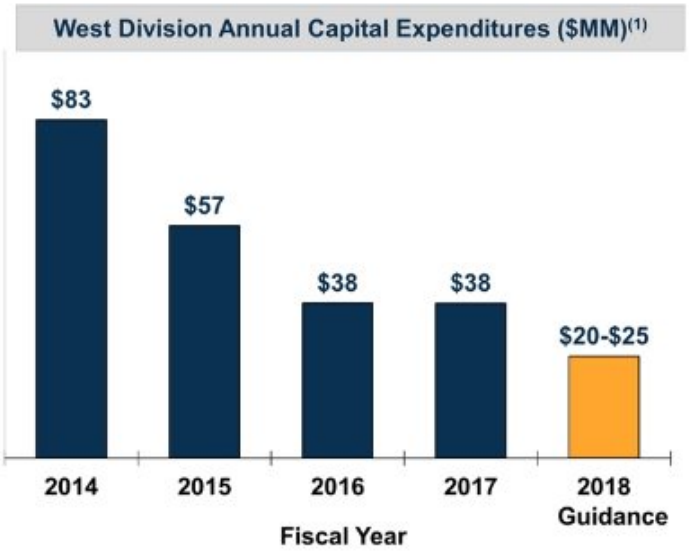
Stable Oil Production | Minimal Capital Investment | Steady Free Cash Flow

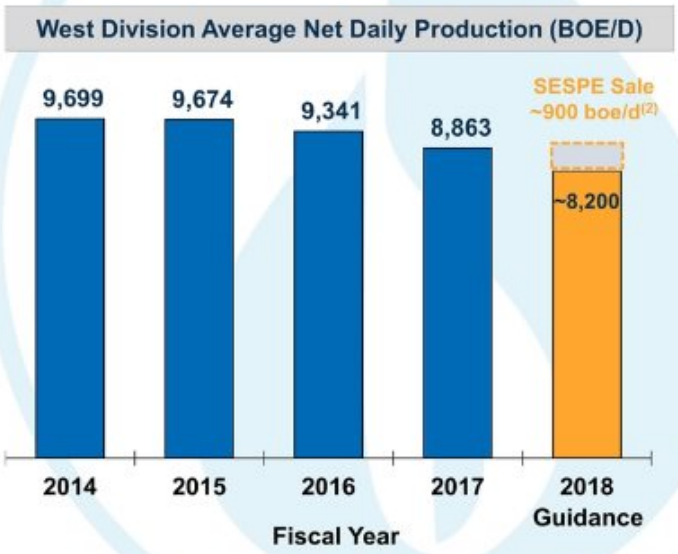


	Location	Formation	Production Method	FY17 Daily Production *(net Boe/d)*
1	East Coalinga	Temblor	Primary	570
2	North Lost Hills	Tulare & Etchegoin	Primary/ Steam flood	933
3	South Lost Hills	Monterey Shale	Primary	1,468
4	North Midway Sunset	Tulare & Potter	Steam flood	3,026
5	South Midway Sunset	Antelope	Steam flood	1,811
6	Sespe	Sespe	Primary	1,055
	TOTAL CALIFORNIA NET PRODUCTION			8,863 Boe/d

Sespe divested on May 1, 2018

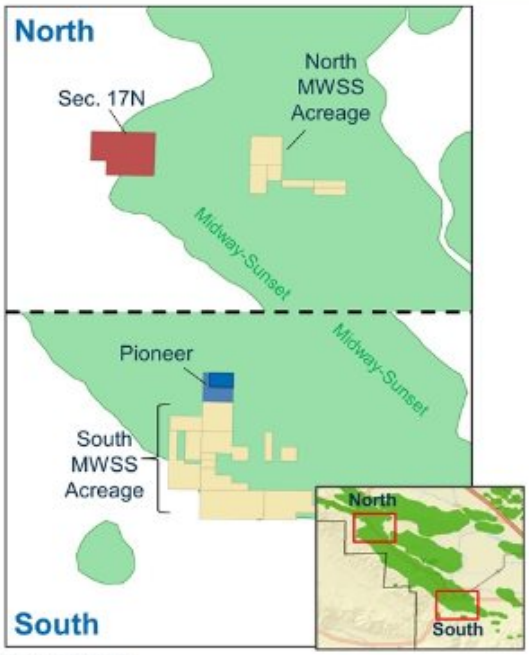
California Capital Expenditures vs. Production





(1) Seneca West Division capital expenditures includes Seneca corporate and eliminations.
(2) Sale closed on 5/1/18. The impact for the remaining 6 months of fiscal 2018 is approximately 175 mboe, or 1.0 Bcfe.

Future Development Focused on Midway Sunset



Midway Sunset Economics

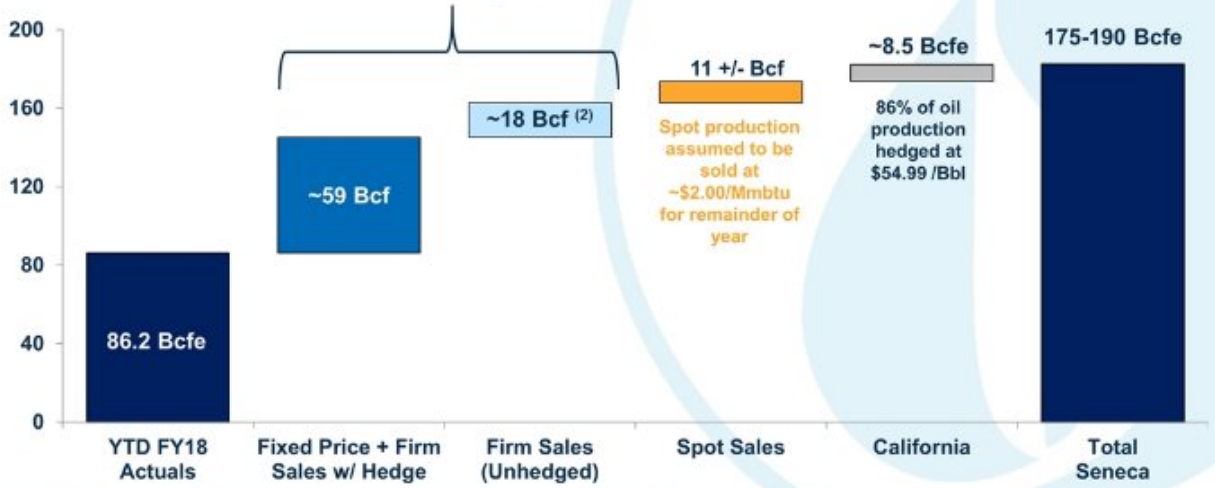
- ✓ Modest near-term capital program focused on locations that earn attractive returns in current oil price environment
- ✓ A&D will focus on low cost, bolt-on opportunities
- ✓ Sec. 17 and Pioneer farm-ins to provide future growth

(1) Reflects pre-tax IRRs at a $60/Bbl WTI.

Fiscal 2018 Production

77 Bcf Protected by Firm Sales for Remainder of Year

- 59 Bcf locked-in realizing net ~$2.44/Mcf [1]
- 18 Bcf of additional basis protection

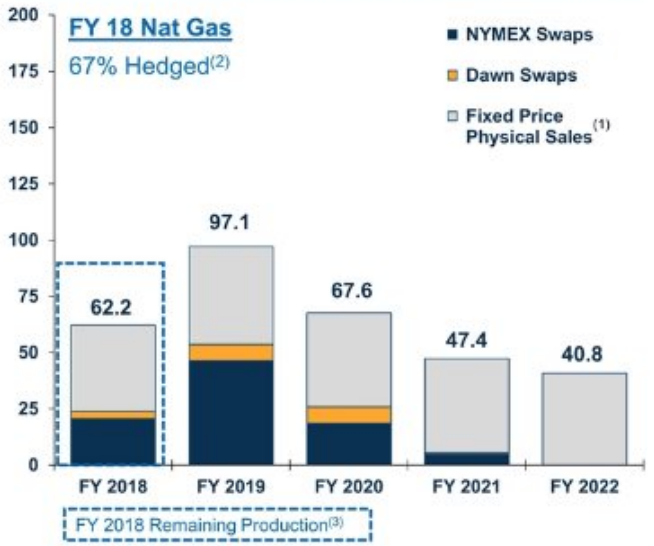


(1) Average realized price reflects uplift from financial hedges less fixed differentials under firm sales contracts and any firm transportation costs.
(2) Indicates firm sales contracts with fixed index differentials but not backed by a matching financial hedge.

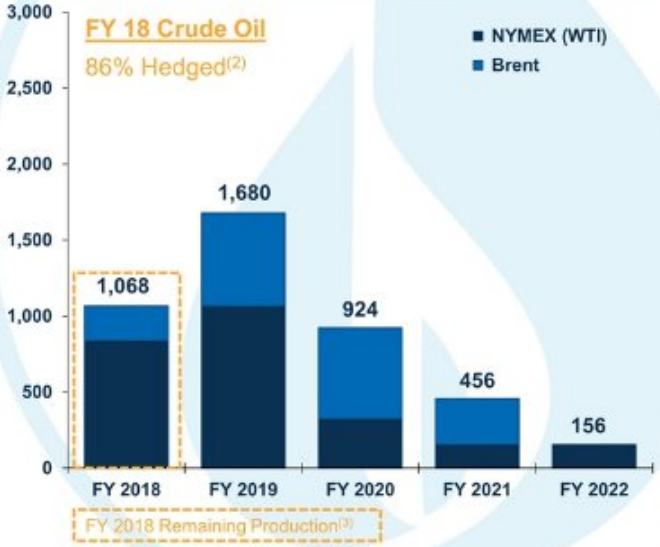
Strong Hedge Book

National Fuel

Natural Gas Swap & Fixed Physical Sales Contracts *(Millions MMBtu)*

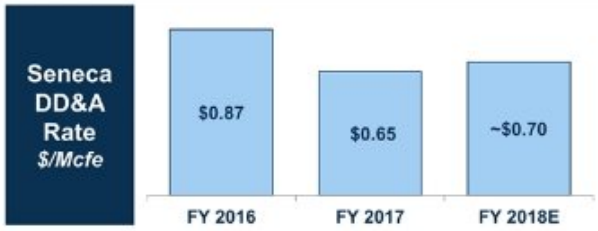


Crude Oil Swap Contracts *(Thousands Bbls)*



(1) Fixed price physical sales exclude joint development partner's share of fixed price contract WDA volumes as specified under the joint development agreement.
(2) Reflects percentage of projected production for the remaining 6 months of FY18 hedged at the midpoint of the production guidance range.
(3) Seneca's remaining FY18 production reflect the total FY18 production guidance 175 to 190Bcfe, or 182.5 Bcfe at the midpoint, less Q1 and Q2 FY18 actual production.

Seneca Operating Costs



- ✓ Competitive, low cost structure in Appalachia and California supports strong cash margins
- ✓ Gathering fee generates significant revenue stream for affiliated gathering company

(1) Excludes $7.9 million , or $0.05 per Mcfe, 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 the LOE guidance range of $0.90 to $1.00 for fiscal 2018.

Pipeline and Storage Overview

National Fuel Gas Supply Corporation ~ Empire Pipeline, Inc.

Pipeline & Storage Segment Overview

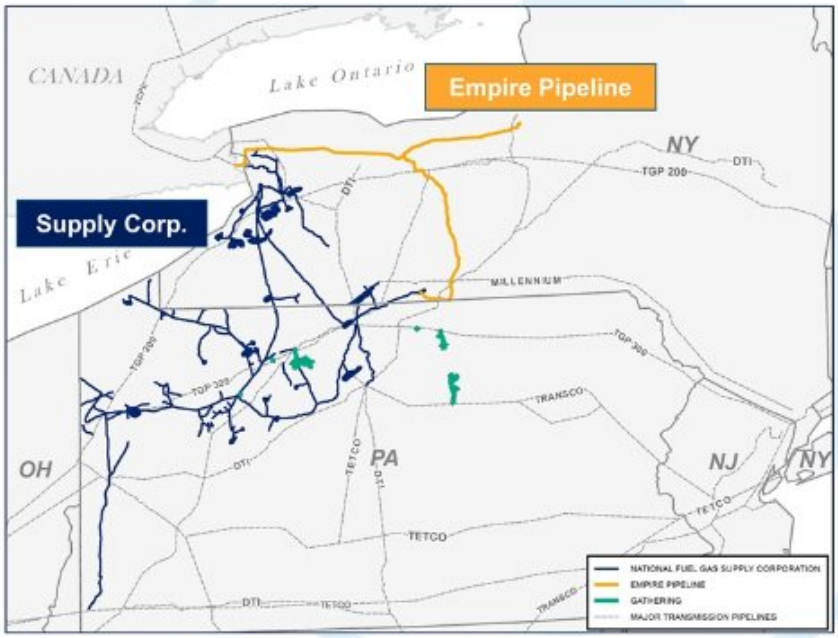
National Fuel

National Fuel Gas Supply Corporation

- **Contracted Capacity[1]:**
  - Firm Transportation: 3,157 MDth per day
  - Firm Storage: 68,042 Mdth (fully subscribed)
- **Rate Base[2]:** ~$820 million
- **FERC Rate Proceeding Status:**
  - Rate case settlement extension approved Nov. '15
  - Required to file a rate case by 12/31/19

Empire Pipeline, Inc.

- **Contracted Capacity[1]:**
  - Firm Transportation: 954 MDth per day
  - Firm Storage: 3,753 Mdth (fully subscribed)
- **Rate Base[2]:** ~$249 million
- **FERC Rate Proceeding Status:**
  - Section 5 rate settlement approved Oct. '16
  - Required to file a rate case by 7/1/21



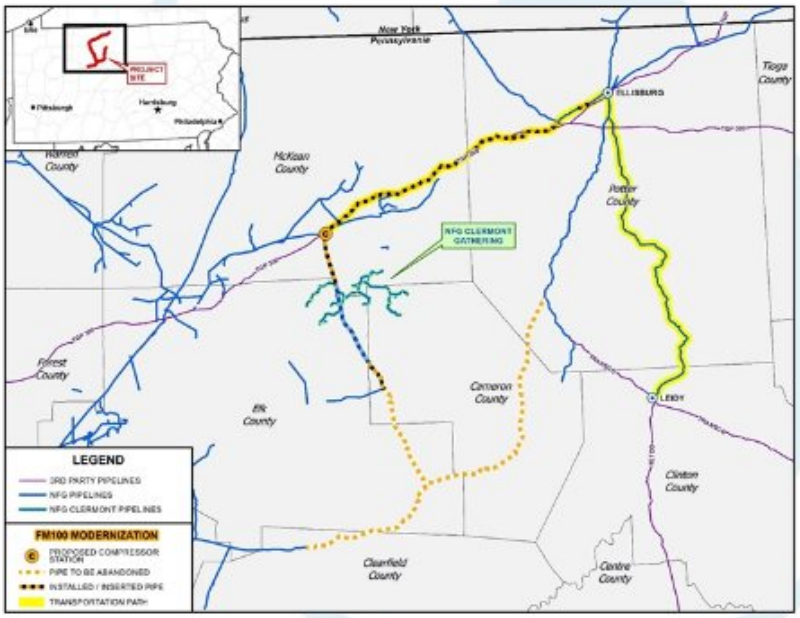
(1) As of September 30, 2017 as disclosed in the Company's fiscal 2017 form 10-K.
(2) As of December 31, 2017 calculated from National Fuel Gas Supply Corporation's and Empire Pipeline, Inc.'s 201 FERC Form-2 reports, respectively.

New Expansion Component of FM100 Modernization

National Fuel

Added expansion component of pending FM100 Modernization Project will provide significant incremental revenues for Supply

- **Target In-Service:** late calendar year 2021
- **Est. Capital:** $250-300M, including modernization component
- **Receipt Point:** Clermont Gathering System
- **Design Capacity:** Approximately 300,000 Dth/d, all of which is expected be leased to Transco
- **Delivery Point:** Supply/Transco interconnection in Leidy, PA
- **Location of Facilities:** all construction in PA
- **Regulatory Process:** FERC 7(b) / 7(c) filing; pre-filing application submitted to FERC in 2017 for original modernization project



Northern Access Project Status

National Fuel Remains Committed to Building the Northern Access Project

Capacity: 490,000 Dth/day

Total Expected Cost: ~$500MM ($75.5MM spent to date, with minimal remaining commitments)

Regulatory Status: FERC issued 7(c) certificate on February 3, 2017

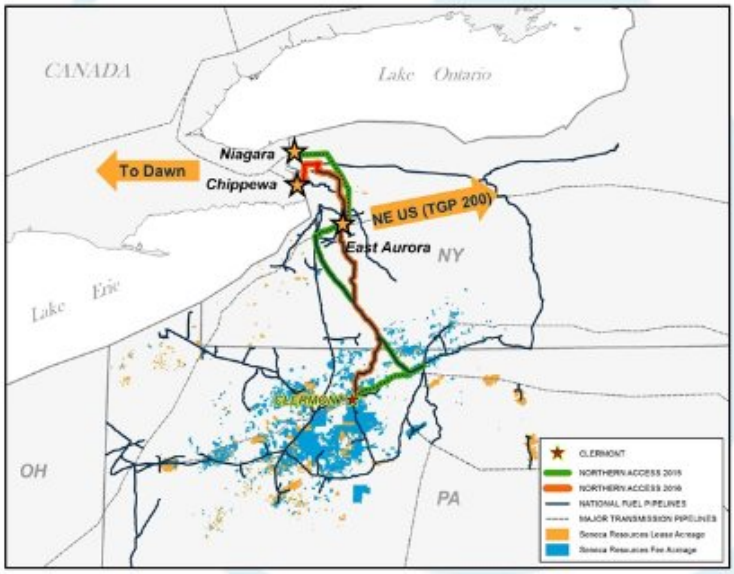
Legal Actions Remain Pending:

✓ US Court of Appeals for the 2nd Circuit:

- On April 21, 2017, NFG filed appeal of NY DEC notice of denial of the Clean Water Act Section 401 Water Quality Certification (WQC)
- Decision from the Court is pending

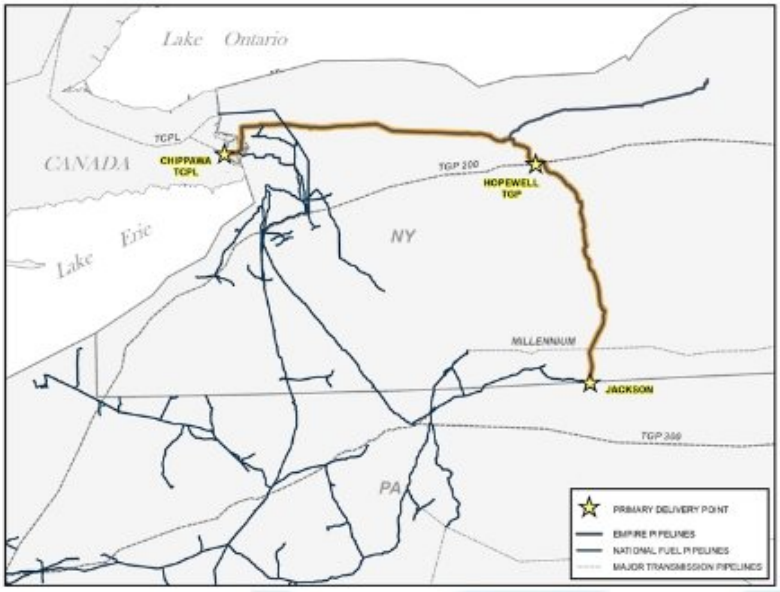
✓ Federal Energy Regulatory Commission:

- On March 3, 2017, NFG filed petition for rehearing with FERC seeking waiver of NY DEC Clean Water Act Section 401 WQC and preemption on state level permits
- Decision from FERC is pending



Empire North Project

- **Target In-Service:** Second half of fiscal 2020
- **Est. Capital Cost:** $142 million
- **Est. Annual Revenues:** $25 million
- **Receipt Point:** Jackson (Tioga Co., Pa. production)
- **Design Capacity and Delivery Points:**
  - 175,000 Dth/d to Chippawa (TCPL interconnect)
  - 30,000 Dth/d to Hopewell (TGP 200 interconnect)
- **Customers:** Fully subscribed (205,000 Dth/day)
- **Major Facilities:**
  - 2 new compressor stations in NY (1) & Pa. (1)
  - No new pipeline construction
- **Regulatory Process:** FERC 7(c) application filed on 2/16/18



Continued Expansion of the NFG Supply System

National Fuel

Line N Expansion Opportunities

Line N to Monaca Project

- **Project:** Firm transportation service to a new ethylene cracker facility being built by Shell Chemical Appalachia, LLC
- **Target In-Service:** July 2019
- **Est. Capital Cost:** $20 million
- **Contracted Capacity:** 133,000 Dth/day

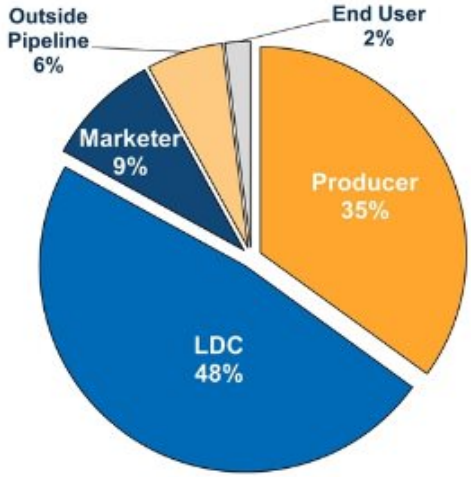
Additional Line N Expansion Opportunity (Supply OS #221)

- **Project:** New firm transportation service for on-system demand
- **Open Season Capacity:** Awarded 165,000 to foundation shipper. Precedent agreement in negotiations.

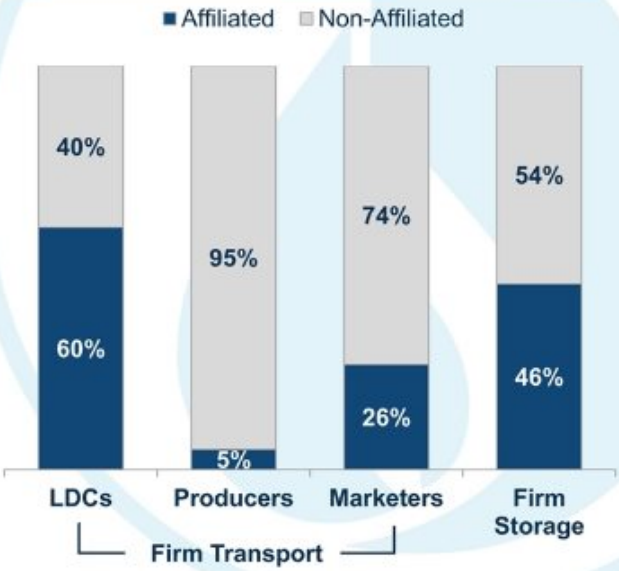
Pipeline & Storage Customer Mix

Customer Transportation by Shipper Type[1]

4.1 MMDth/d



Affiliated Customer Mix (Contracted Capacity)



(1) Contracted as of 11/1/2017.

Utility Overview

National Fuel Gas Distribution Corporation

New York & Pennsylvania Service Territories

New York

Total Customers[1]: 530,400

ROE: 8.7% (NY PSC Rate Case Order, April 2017)

Rate Mechanisms:

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

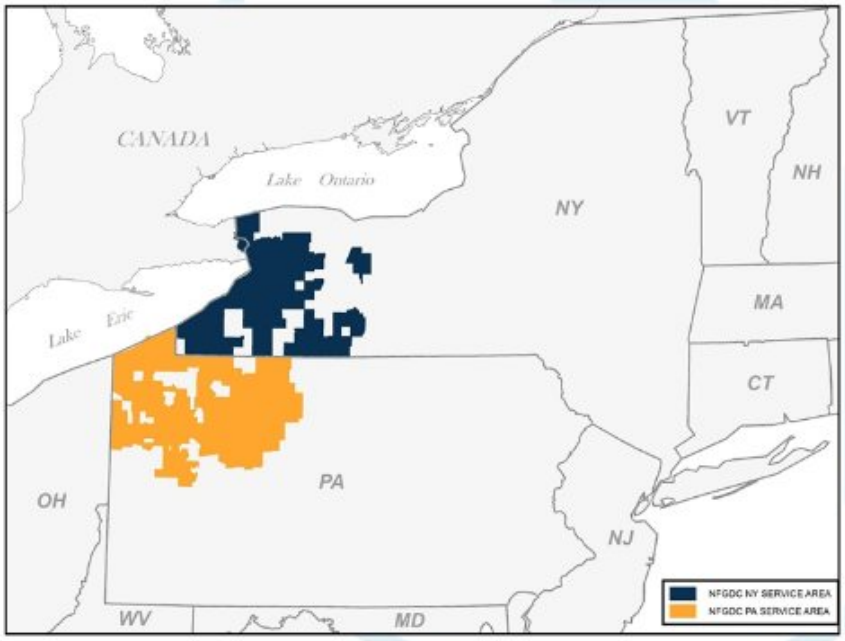
Pennsylvania

Total Customers[1]: 213,200

ROE: Black Box Settlement (2007)

Rate Mechanisms:

- Low Income Rates
- Merchant Function Charge



(1) As of September 30, 2017.

New York Rate Case Outcome

On April 20, 2017, the New York Public Service Commission issued a Rate Order relating to NFG Distribution's rate case (No. 16-G-0257) filed in April 2016.

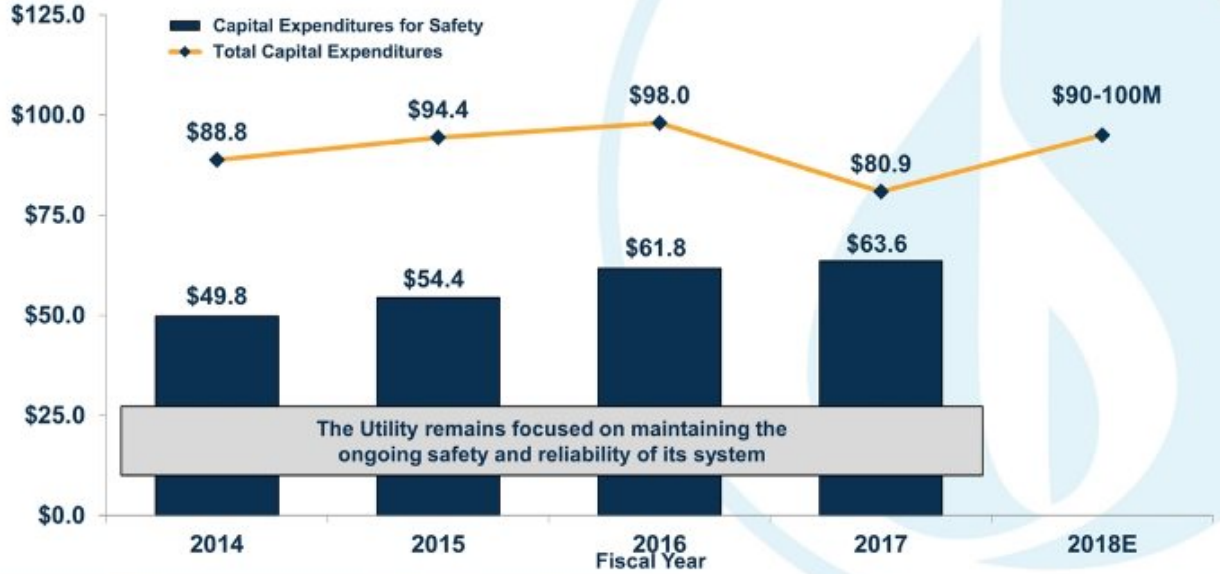
Rate Order Summary:

- **Revenue Requirement:** $5.9 million
- **Rate Base:** $704 million (prior case $632 million[1])
- **Allowed Return on Equity (ROE):** 8.7% (prior case allowed 9.1%[1])
- **Capital Structure:** 42.9% equity
- **Other notable items:**
  - New rates became effective 5/1/17
  - Retains rate mechanisms in place under prior order (revenue decoupling, weather normalization, merchant function charge, 90/10 large customer sharing)
  - No stay-out clause
  - Earnings sharing would start 4/1/18 if Distribution Corp. does not file for new rates to become effective on or before 10/1/18 (50/50 sharing starts at earnings in excess of 9.1%)
  - Article 78 appeal filed on 7/28/17
  - Commission approved Leak Prone Pipe (LPP) tracker in February 2018

(1) Case 13-G-0136 rate year ended September 30, 2015.

Utility: Strong Commitment to Safety

Capital Expenditures ($ millions)[1]



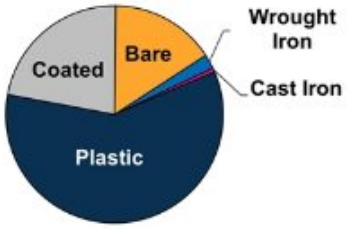
(1) A reconciliation to Capital Expenditures as presented on the Consolidated Statement of Cash Flows is included at the end of this presentation.

Accelerating Pipeline Replacement & Modernization

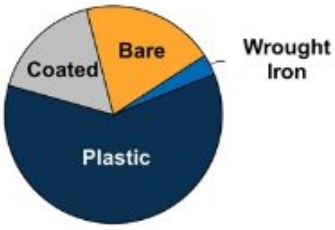
National Fuel

Utility Mains by Material

NY
9,723 miles

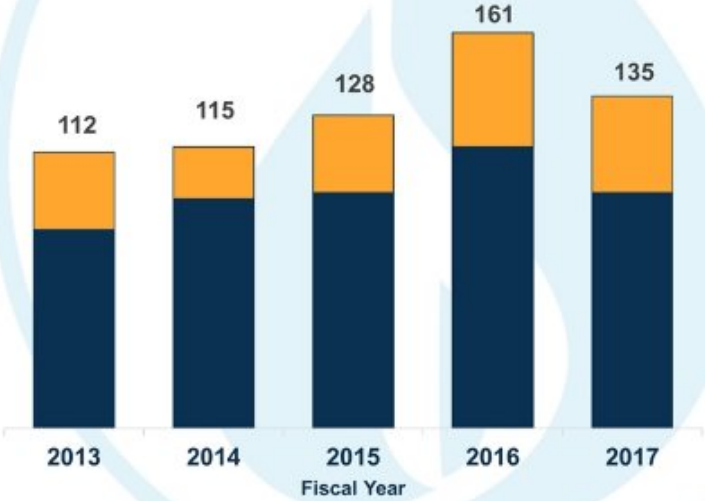


PA*
4,832 miles



** No Cast Iron Mains in Pa.**

Miles of Utility Main Pipeline Replaced

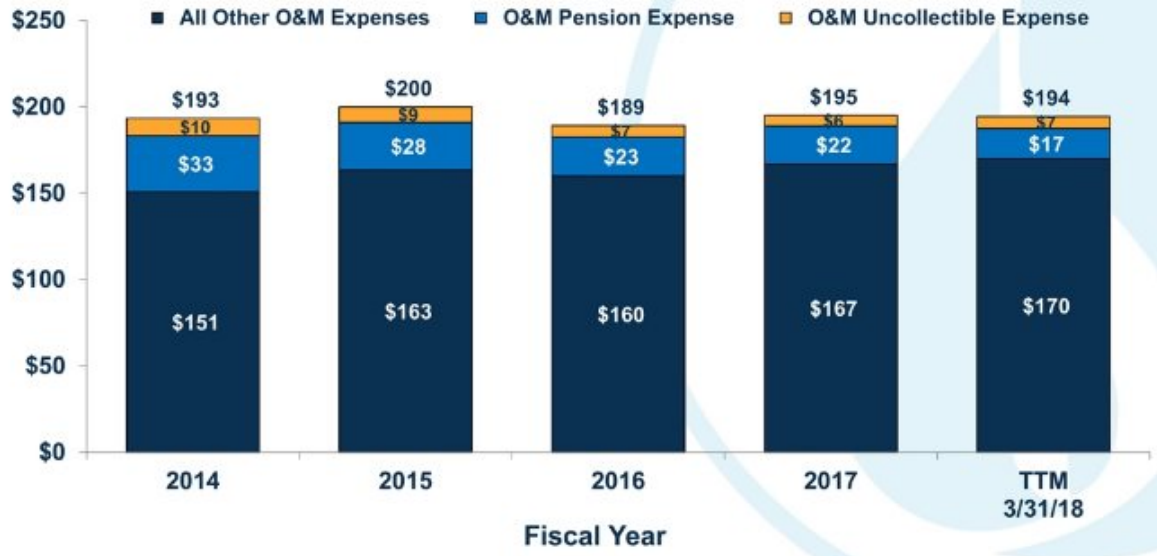


Utility

National Fuel

A Proven History of Controlling Costs

O&M Expense ($ millions)



Appendix

Hedge Positions and Prices

National Fuel

Natural Gas Volumes in thousand MMBtu; Prices in $/MMBtu

	Fiscal 2018 (last 6 mos.)		Fiscal 2019		Fiscal 2020		Fiscal 2021		Fiscal 2022	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
NYMEX Swaps	20,520	$3.17	46,420	$3.03	18,640	$3.04	4,840	$3.01	-	-
Dawn Swaps	3,600	$3.00	7,200	$3.00	7,200	$3.00	600	$3.00	-	-
Fixed Price Physical[1]	38,110	$2.33	43,507	$2.44	41,717	$2.28	41,937	$2.22	40,840	$2.23
Total	**62,230**	**$2.65**	**97,127**	**$2.76**	**67,557**	**$2.57**	**47,377**	**$2.31**	**40,840**	**$2.23**

Crude Oil Volumes & Prices in Bbl

	Fiscal 2018 (last 6 mos.)		Fiscal 2019		Fiscal 2020		Fiscal 2021		Fiscal 2022	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
Brent Swaps	228,000	$63.55	612,000	$61.26	600,000	$59.60	300,000	$60.00	-	-
NYMEX Swaps	840,000	$52.67	1,068,000	$53.42	324,000	$50.52	156,000	$51.00	156,000	$51.00
Total	**1,068,000**	**$54.99**	**1,680,000**	**$56.28**	**924,000**	**$56.42**	**456,000**	**$56.92**	**156,000**	**$51.00**

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

Appalachia Drilling Program Economics

National Fuel

Large Inventory of Marcellus and Utica Location Economic Below $2.00/MMBtu[1]

	Prospect	Reservoir	Locations Remaining to Be Drilled	Completed Lateral Length (ft)	EUR / 1000' (Bcf)	Well Cost $M/1,000 ft	Internal Rate of Return % [2]			Realized Price[1] Required for 15% IRR	Anticipated Delivery Markets
							$2.50 Realized	$2.25 Realized	$2.00 Realized		
EDA	Tract 100 & Gamble *Lycoming Co.*	Marcellus	51	4,900	2.5	$1,054	76%	59%	44%	$1.54	**Transco Leidy & Atlantic Sunrise** Southeast US (NYMEX+)
EDA	DCNR 007 *Tioga Co.*	Utica	48	8,300	2.0	$985	52%	38%	23%	$1.83	**TGP 300**
WDA	Clermont Rich Valley	Utica	125 - 500+	8,000	1.7	$921	29%	23%	16%	$1.96	**TGP 300 & Niagara Expansion** Canada (Dawn)
WDA	Core Areas	Marcellus	632	8,500	1.0 to 1.1	$648	26%	19%	14%	$2.09	

(1) Net realized price reflects either (a) price received at the gathering system interconnect or (b) price received at delivery market net of firm transportation charges.
(2) 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.

Firm Transportation Commitments

National Fuel

		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 = $0.24 3rd party = $0.43	Firm Sales Contracts 158,000 Dth/d Dawn/NYMEX+ 8 to 15 years
Currently In-Service			12,000	TETCO (SE Pa.)	NFG pipelines = $0.12	
Future Capacity	**Atlantic Sunrise** *WMB - Transco In-service: Mid-2018*	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
Future Capacity	**Transco Expansion / FM100 Project** *WMB – Transco; NFG - Supply In-service: ~ late 2021*	WDA – Clermont/ Rich Valley and EDA - Lycoming County	~300,000	Transco Zone 6	Expected to be competitive with other expansion project rates in Seneca's transportation portfolio(1)	Seneca to pursue Firm Sales Contracts as project development progresses
Future Capacity	**Northern Access** *NFG – Supply & Empire Delayed*	WDA – Clermont/ Rich Valley	350,000	Canada (Dawn)	NFG pipelines = $0.50 3rd party = $0.21	Firm Sales Contracts At Dawn When Project Goes In-Service
Future Capacity			140,000	TGP 200 (NY)	NFG pipelines = $0.38	

(1) Significant portion of transportation rate paid by Seneca to Transco is expected to flow back to NFG via a lease between Transco and Supply Corp.

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 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.

Management defines Adjusted Operating Results as reported GAAP earnings before items impacting comparability.

The Company's fiscal 2018 earnings guidance does not include the impact of the remeasurement of deferred income taxes resulting from the 2017 Tax Reform Act, which reduced the Company's consolidated income tax expense and benefited earnings for the six months ended March 31, 2018 by $107.0 million, or $1.24 per share. While the Company expects to record additional adjustments to its deferred income taxes as a result of the 2017 Tax Reform Act during the remaining six months of fiscal 2018, the amounts of these and other potential adjustments are not reasonably determinable at this time. The final determination of the impact of the income tax effects of certain items will require additional analysis and further interpretation of the 2017 Tax Reform Act from yet to be issued U.S. Treasury regulations, state income tax guidance, federal and state regulatory guidance, technical corrections, and the filing of the Company's fiscal 2017 federal consolidated tax return. Some or all of these factors may be significant. Because the amounts of final adjustments are not reasonably determinable at this time, the Company is unable to provide earnings guidance other than on a non-GAAP basis that excludes the impact of the remeasurement of deferred income taxes and other potential adjustments.

Management defines Adjusted EBITDA as reported GAAP earnings before the following items: interest expense, income taxes, depreciation, depletion and amortization, interest and other income, impairments, and other items reflected in operating income that impact comparability.

Non-GAAP Reconciliations – Adjusted Operating Results

National Fuel

(in thousands except per share amounts)	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Six Months Ended March 31, 2018	Six Months Ended March 31, 2017
Reported GAAP Earnings	$ 91,847	$ 89,284	$ 290,501	$ 178,191
Items impacting comparability				
Remeasurement of deferred income taxes under 2017 Tax Reform	4,000	—	(107,000)	—
Adjusted Operating Results	$ 95,847	$ 89,284	$ 183,501	$ 178,191
Reported GAAP Earnings per share	$ 1.06	$ 1.04	$ 3.37	$ 2.07
Items impacting comparability				
Remeasurement of deferred income taxes under 2017 Tax Reform	$ 0.05	—	$ (1.24)	—
Adjusted Operating Results per share	$ 1.11	$ 1.04	$ 2.13	$ 2.07

Non-GAAP Reconciliations – Adjusted EBITDA

National Fuel

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

	FY 2014	FY 2015	FY 2016	FY 2017	12-Months Ended 3/31/18
Total Adjusted EBITDA					
Exploration & Production Adjusted EBITDA	$ 539,472	$ 422,289	$ 363,830	$ 360,979	$ 322,796
Pipeline & Storage Adjusted EBITDA	186,022	188,042	199,446	180,328	184,127
Gathering Adjusted EBITDA	64,060	68,881	78,685	94,380	89,976
Utility Adjusted EBITDA	164,643	164,037	148,683	151,078	150,166
Energy Marketing Adjusted EBITDA	10,335	12,237	6,855	2,080	456
Corporate & All Other Adjusted EBITDA	(11,078)	(11,900)	(8,238)	(11,805)	(10,089)
Total Adjusted EBITDA	**$ 953,454**	**$ 843,586**	**$ 789,061**	**$ 777,040**	**$ 737,432**
Total Adjusted EBITDA	**$ 953,454**	**$ 843,586**	**$ 789,061**	**$ 777,040**	**$ 737,432**
Minus: Interest Expense	(94,277)	(99,471)	(121,044)	(119,837)	(116,958)
Plus: Interest and Other Income	13,631	11,961	14,055	11,156	11,576
Minus: Income Tax Expense	(189,614)	319,136	232,549	(160,682)	(8,272)
Minus: Depreciation, Depletion & Amortization	(383,781)	(336,158)	(249,417)	(224,195)	(227,986)
Minus: Impairment of Oil and Gas Properties (E&P)	-	(1,126,257)	(948,307)	-	-
Plus: Reversal of Stock-Based Compensation (all segments)	-	7,776	-	-	-
Minus: Joint Development Agreement Professional Fees (E&P)	-	-	(7,855)	-	-
Minus: Regulatory Refund Provision (Utility)	-	-	-	-	-
Rounding	-	-	-	-	-
Consolidated Net Income	**$ 299,413**	**$ (379,427)**	**$ (290,958)**	**$ 283,482**	**$ 395,792**
Consolidated Debt to Total Adjusted EBITDA					
Long-Term Debt, Net of Current Portion (End of Period)	$ 1,649,000	$ 2,099,000	$ 2,099,000	$ 2,099,000	$ 2,099,000
Current Portion of Long-Term Debt (End of Period)	-	-	-	300,000	-
Notes Payable to Banks and Commercial Paper (End of Period)	85,600	-	-	-	-
Less: Cash and Temporary Cash Investments (End of Period)	(36,886)	(113,596)	(129,972)	(555,530)	(227,994)
Total Net Debt (End of Period)	$ 1,697,714	$ 1,985,404	$ 1,969,028	$ 1,843,470	$ 1,871,006
Long-Term Debt, Net of Current Portion (Start of Period)	1,649,000	1,649,000	2,099,000	2,099,000	2,099,000
Current Portion of Long-Term Debt (Start of Period)	-	-	-	-	-
Notes Payable to Banks and Commercial Paper (Start of Period)	-	85,600	-	-	-
Less: Cash and Temporary Cash Investments (Start of Period)	(64,858)	(36,886)	(113,596)	(129,972)	(231,173)
Total Net Debt (Start of Period)	$ 1,584,142	$ 1,697,714	$ 1,985,404	$ 1,969,028	$ 1,867,827
Average Total Debt	**$ 1,640,928**	**$ 1,841,559**	**$ 1,977,216**	**$ 1,906,249**	**$ 1,869,417**
Average Total Debt to Total Adjusted EBITDA	**1.72 x**	**2.18 x**	**2.51 x**	**2.45 x**	**2.54 x**

Non-GAAP Reconciliations – Capital Expenditures

National Fuel

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018 Forecast
Capital Expenditures					
Exploration & Production Capital Expenditures	$ 602,705	$ 557,313	$ 256,104	$ 253,057	$350,000 - $370,000
Pipeline & Storage Capital Expenditures	$ 139,821	$ 230,192	$ 114,250	$ 95,336	$110,000 - $130,000
Gathering Segment Capital Expenditures	$ 137,799	$ 118,166	$ 54,293	$ 32,645	$60,000 - $80,000
Utility Capital Expenditures	$ 88,810	$ 94,371	$ 98,007	$ 80,867	$90,000 - $100,000
Energy Marketing, Corporate & All Other Capital Expenditures	$ 772	$ 467	$ 397	$212	
Total Capital Expenditures from Continuing Operations	$ 969,907	$ 1,000,509	$ 523,051	$ 462,117	$610,000 - $680,000
Plus (Minus) Accrued Capital Expenditures					
Exploration & Production FY 2017 Accrued Capital Expenditures				$ (36,465)	
Exploration & Production FY 2016 Accrued Capital Expenditures	-	-	(25,215)	25,215	
Exploration & Production FY 2015 Accrued Capital Expenditures	-	(46,173)	46,173	-	
Exploration & Production FY 2014 Accrued Capital Expenditures	(80,108)	80,108	-	-	
Exploration & Production FY 2013 Accrued Capital Expenditures	58,478	-	-	-	
Exploration & Production FY 2012 Accrued Capital Expenditures	-	-	-	-	
Pipeline & Storage FY 2017 Accrued Capital Expenditures				(25,077)	
Pipeline & Storage FY 2016 Accrued Capital Expenditures	-	-	(18,661)	18,661	
Pipeline & Storage FY 2015 Accrued Capital Expenditures	-	(33,925)	33,925	-	
Pipeline & Storage FY 2014 Accrued Capital Expenditures	(28,122)	28,122	-	-	
Pipeline & Storage FY 2013 Accrued Capital Expenditures	5,633	-	-	-	
Pipeline & Storage FY 2012 Accrued Capital Expenditures	-	-	-	-	
Gathering FY 2017 Accrued Capital Expenditures				(3,925)	
Gathering FY 2016 Accrued Capital Expenditures	-	-	(5,355)	5,355	
Gathering FY 2015 Accrued Capital Expenditures	-	(22,416)	22,416	-	
Gathering FY 2014 Accrued Capital Expenditures	(20,084)	20,084	-	-	
Gathering FY 2013 Accrued Capital Expenditures	6,700	-	-	-	
Gathering FY 2012 Accrued Capital Expenditures	-	-	-	-	
Utility FY 2017 Accrued Capital Expenditures				(8,748)	
Utility FY 2016 Accrued Capital Expenditures	-	-	(11,203)	11,203	
Utility FY 2015 Accrued Capital Expenditures	-	(16,445)	16,445	-	
Utility FY 2014 Accrued Capital Expenditures	(8,315)	8,315	-	-	
Utility FY 2013 Accrued Capital Expenditures	10,328	-	-	-	
Utility FY 2012 Accrued Capital Expenditures	-	-	-	-	
Total Accrued Capital Expenditures	$ (55,490)	$ 17,670	$ 58,525	$ (11,782)	
Total Capital Expenditures per Statement of Cash Flows	**$ 914,417**	**$ 1,018,179**	**$ 581,576**	**$ 450,335**	**$610,000 - $680,000**

Non-GAAP Reconciliations – E&P Operating Expenses

National Fuel

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

	Twelve Months Ended September 30, 2017						Twelve Months Ended September 30, 2016					
	Appalachia	West Coast[2]	Total E&P	Appalachia	West Coast[2]	Total E&P	Appalachia	West Coast[2]	Total E&P	Appalachia	West Coast[2]	Total E&P
				$/Mcfe	$/Boe	$/Mcfe				$/Mcfe	$/Boe	$/Mcfe
Operating Expenses:												
Gathering & Transportation Expense [1]	$92,874	$502	$93,376	$0.60	$0.18	$0.54	$82,949	$309	$83,258	$0.59	$0.09	$0.52
Other Lease Operating Expense	$16,625	$55,990	$72,615	$0.11	$17.31	$0.42	$20,402	$50,254	$70,656	$0.14	$14.74	$0.44
Lease Operating and Transportation Expense	$109,499	$56,492	$165,991	$0.71	$17.48	$0.96	$103,351	$50,563	$153,914	$0.73	$14.83	$0.96
General & Administrative Expense			$58,734			$0.34			$70,598			$0.44
All Other Operating and Maintenance Expense			$13,469			$0.08			$12,832			$0.08
Property, Franchise and Other Taxes			$15,426			$0.09			$13,794			$0.09
Total Taxes & Other			$28,895			$0.17			$26,626			$0.17
Depreciation, Depletaion & Amortization			$112,565			$0.65			$139,963			$0.87
Production:												
Gas Production (MMcf)				154,093	2,995	157,088				140,457	3,090	143,547
Oil Production (MBbl)				4	2,736	2,740				28	2,895	2,923
Total Production (Mmcfe)				154,117	19,411	173,528				140,625	20,460	161,085
Total Production (Mboe)				25,686	3,235	28,921				23,438	3,410	26,848

(1) Gathering and Transportation expense is net of any payments received from JDA partner for the partner's share of gathering cost
(2) Seneca West Coast division includes Seneca corporate and eliminations.