Investor Presentation

Q4 Fiscal 2018 Update

November 1, 2018

National Fuel is committed to the safe and environmentally conscious development, transportation, storage, and distribution of natural gas and oil resources.

National Fuel's Guiding Principles

Safety
We value the safety of all of our customers, employees, and communities, and work diligently to establish a culture of safety that is embraced throughout the organization.

Innovation
We strive to exceed the standards for safe, clean, and reliable energy development. We invest in the future of our regions' energy resources. We envision a long and healthy future for our Company.

Environmental Stewardship
We play a unique and vital role in upholding standards of environmental protection in every area of our business. We are proactive and detailed in our compliance with local, state, and federal laws.

Satisfaction
We work to deliver reliable, high quality service for our customers. We want our shareholders to see a strong return on their investment. We want our employees to work in a positive, safe, and rewarding environment. We want our communities to be proud to call us neighbors.

Community
We are committed to the health and vitality of our local communities. We work where we live and raise our families, and are constantly focused on the highest standards of corporate responsibility and accountability.

Transparency
We believe that open communication is key is maintaining strong relationships. We see value in educating our customers, shareholders, employees, and the larger community about all aspects of our work.

For additional information, please visit our corporate responsibility website at https://responsibility.natfuel.com

NFG: A Diversified, Integrated Natural Gas Company

National Fuel®

Upstream
Exploration & Production

2018 — *43% of NFG EBITDA[(2)]*

Developing our large, high quality acreage position in Marcellus & Utica shales[(1)]

785,000 Net acres in Appalachia

489 MMcf/day Net Appalachian natural gas production

Midstream
Gathering Pipeline & Storage

2018 — *37% of NFG EBITDA[(2)]*

Expanding and modernizing pipeline infrastructure to provide outlets for Appalachian natural gas production

$1.5 Billion Investments since 2010

4.3 MMDth Daily interstate pipeline capacity under contract

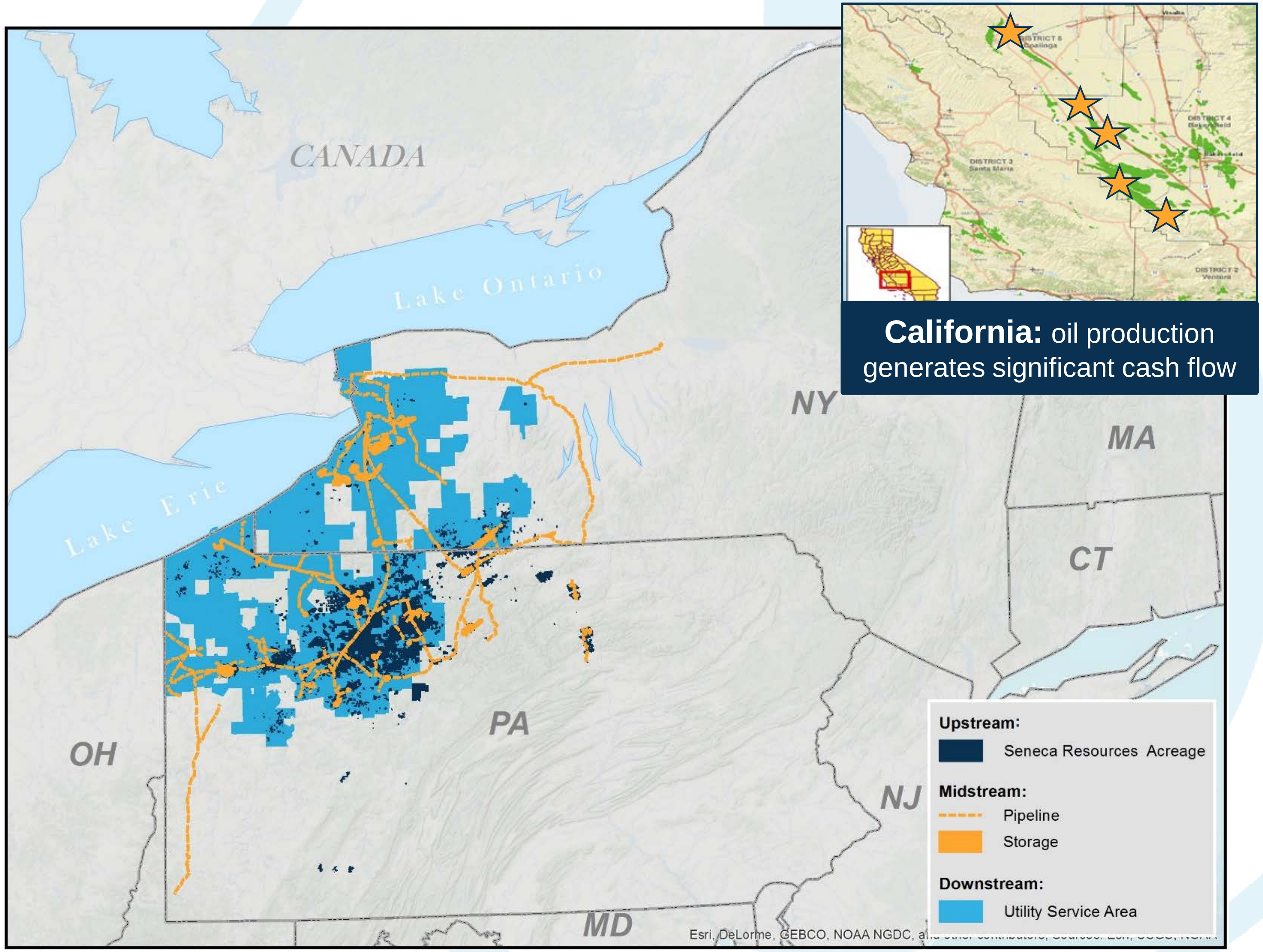
Downstream
Utility Energy Marketing

2018 — *20% of NFG EBITDA[(2)]*

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

750,000 Utility Customers

$300 Million Investments in safety since 2014



California: oil production generates significant cash flow

(1) This presentation includes forward-looking statements. Please review the safe harbor for forward looking statements on slide 56 of this presentation.
(2) A reconciliation of FY 2018 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..

Why National Fuel?

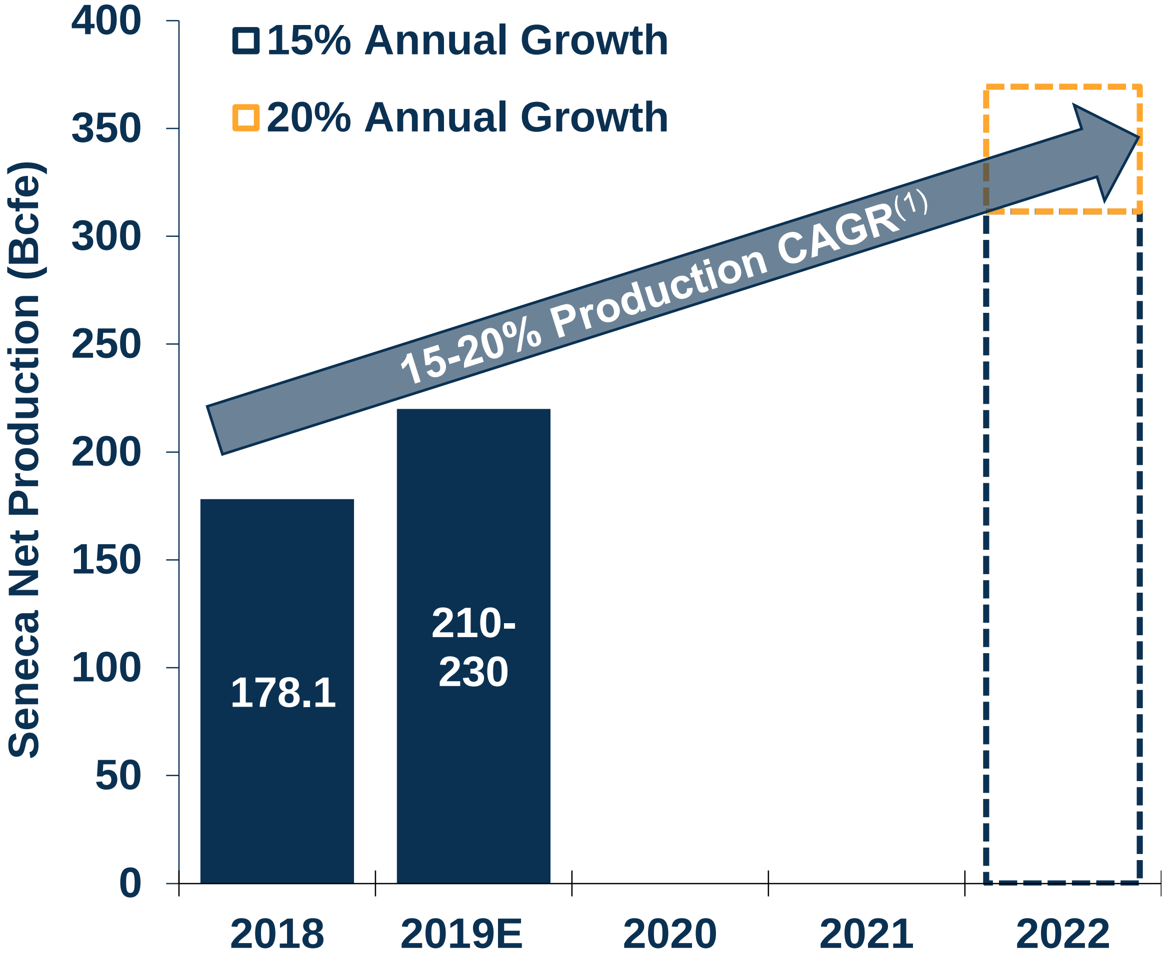
Large Appalachian Footprint Driving Significant Growth

1. **Annual Production and Gathering Growth of 15-20% Expected Through 2022**
2. **Utilization of Existing Infrastructure Amplifies Consolidated Returns**
3. **$1 Billion+ Pipeline & Storage Project Backlog**
4. **Long History of Returning Capital to Shareholders**
5. **Integrated Model Enhances Shareholder Value**

1 Production and Gathering Growth of 15-20% Through 2022

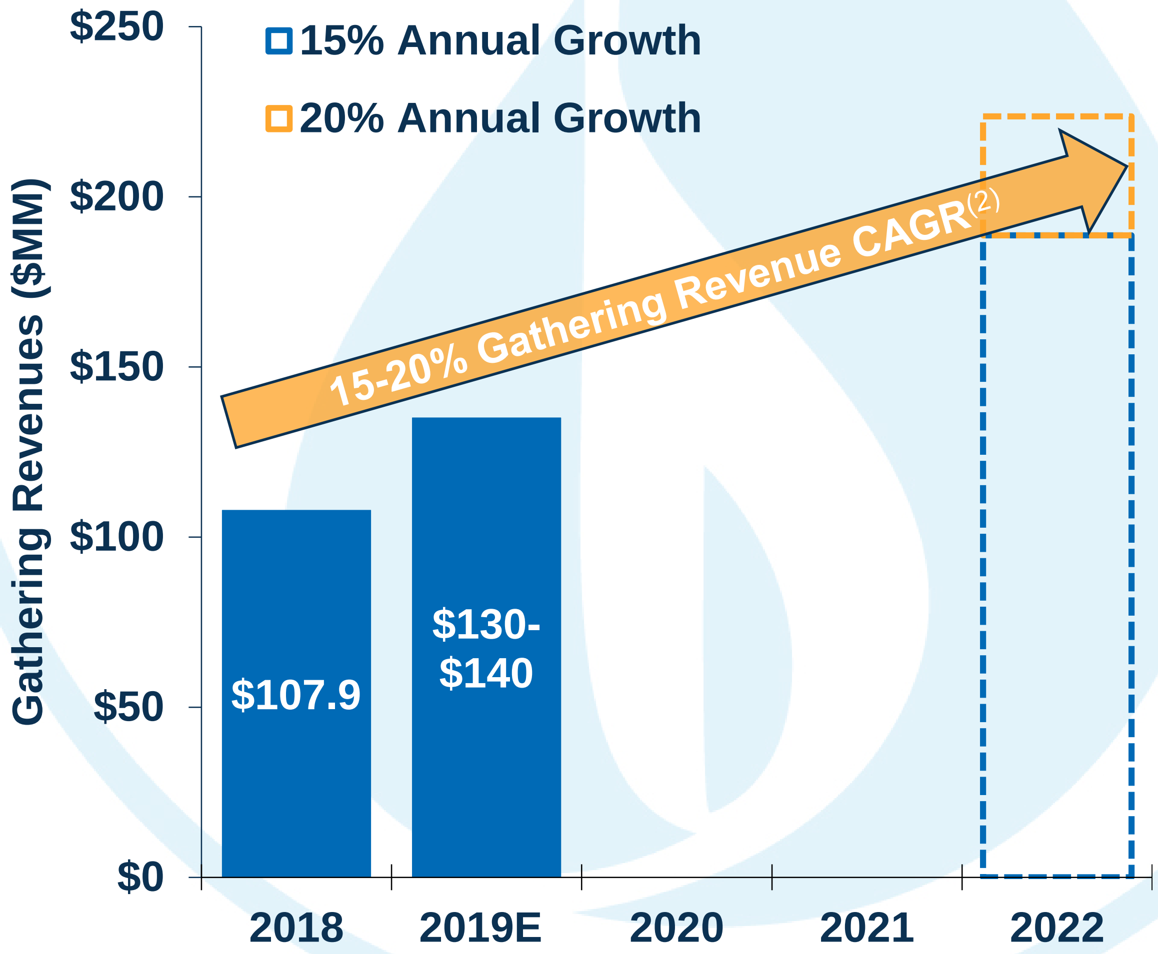
National Fuel

Addition of Third Drilling Rig Expected to Drive Significant Production Growth



(1) Production trend line represents 17.5% net growth, on average, from fiscal 2018 through fiscal 2022

Production Growth Drives Significant Increase in Gathering Revenues



(2) Revenue trend line represents 17.5% growth, on average, from fiscal 2018 through fiscal 2022

2 Leveraging Existing Infrastructure to Enhance Returns

National Fuel

Utilization of Existing Infrastructure for Ongoing Utica Development Amplifies Consolidated Returns

Utica development on Marcellus pads allows use of existing:

- ✓ **Gathering Pipelines**
- ✓ **Compression**
- ✓ **Water Handling Facilities**
- ✓ **Roadways and Pads**

Requires modest investment in new Gathering facilities to support production growth

Gathering Costs in Western Development Area (CRV)

	Gathering CapEx/Well ($ thousands)
Marcellus (pre-2018)	$1,723[1]
Utica (2018-2022)	$375[2]

Resulting in significant consolidated return uplift for E&P and Gathering

10+% IRR Uplift Expected[3]

(1) Approximate WDA Marcellus gathering facility costs for the 166 wells drilled and completed to date.
(2) Estimated WDA Utica gathering facility costs for the assumed 125 well locations in Clermont Rich Valley area of redevelopment.
(3) Internal Rate of Return for Seneca WDA includes estimated well costs under current cost structure, and anticipated LOE and Gathering costs. Internal Rate of Return for Seneca WDA and Gathering includes expected gathering capital expenditures through FY 2022, well costs under current cost structure, and non-gathering LOE.

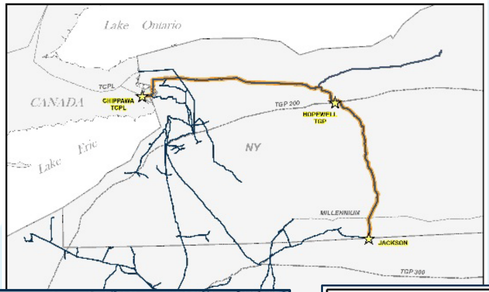
3 $1 Billion+ Backlog in Pipeline & Storage Projects

- ✓ **Line N to Monaca -** <u>$23 MM </u>(July 2019)[1]
- ✓ **Empire North** - <u>$145 MM </u>(second half of fiscal 2020)
- ✓ **FM100** - <u>$280 MM </u>(late calendar 2021)
- ✓ **Northern Access** - <u>$500 MM </u>(first half of fiscal 2022)
- ✓ **Supply Corp. Modernization -** <u>$150 - $250 MM</u> (fiscal 2019-2022)

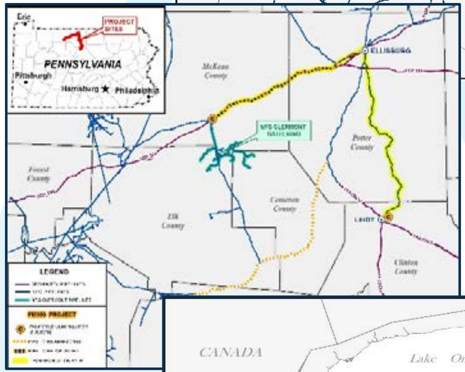
FUTURE INVESTMENTS = <u>$1.1 – $1.2 Billion</u>

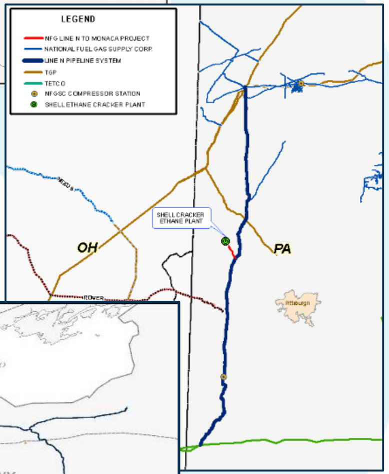
FUTURE EXPANSION REVENUES = <u>~$150 Million</u>

Empire North

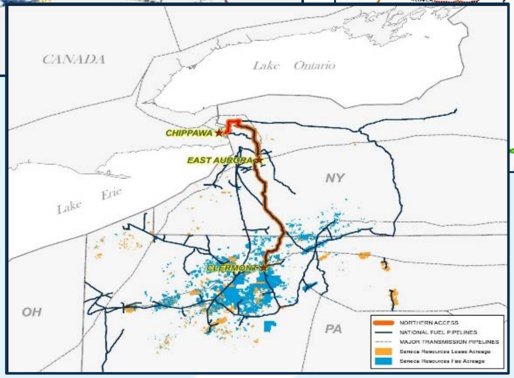


FM100





Line N to Monaca



Northern Access

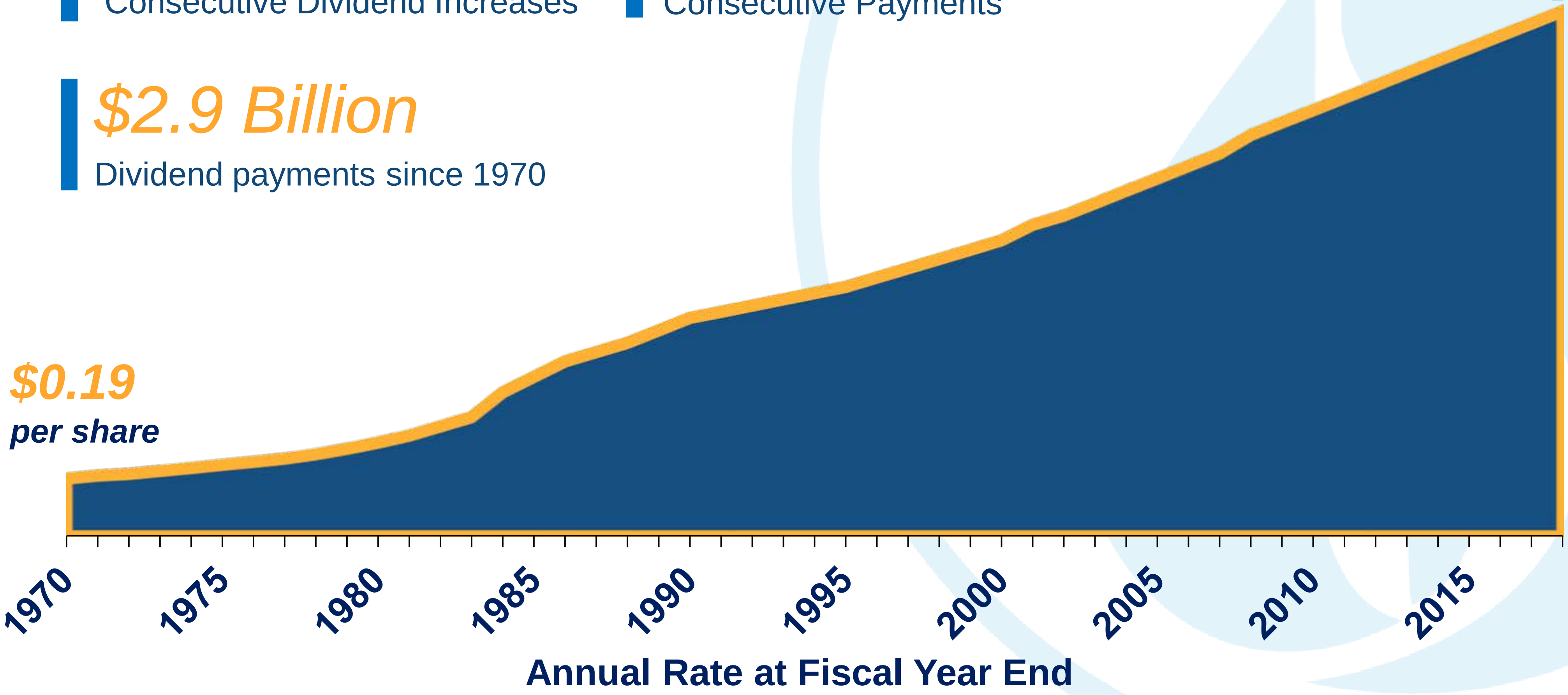
(1) Parentheticals represent target in-service dates for the respective expansion projects.

Nearly 50 Years of Consecutive Dividend Increases

48 Years
Consecutive Dividend Increases

116 Years
Consecutive Payments

$2.9 Billion
Dividend payments since 1970

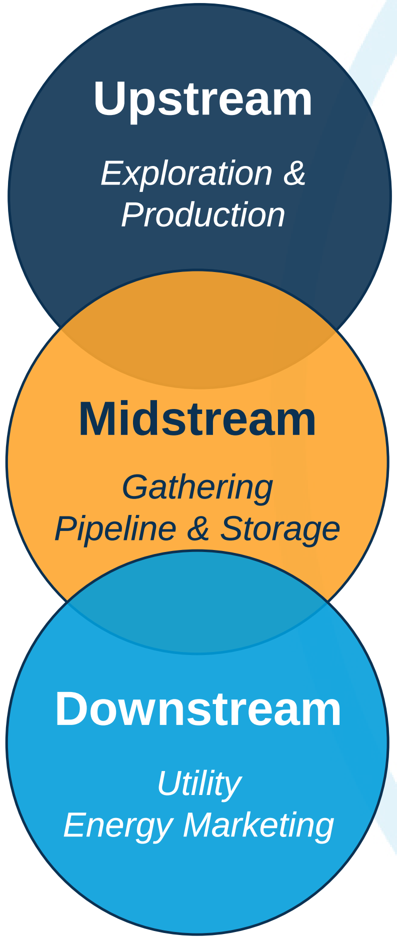


(1) As of October 30, 2018.

5 Integrated Model Enhances Shareholder Value

Benefits of National Fuel's Integrated Structure:

- ✓ **Operational scale**
- ✓ **Lower cost of capital**
- ✓ **Lower operating costs**
- ✓ **More efficient capital investment**
- ✓ **More competitive pipeline infrastructure projects**
- ✓ **Ability to adjust to changing commodity price environments**
- ✓ **Higher returns on investment**
- ✓ **Strong balance sheet**
- ✓ **Growing, stable dividend**



Geographic and Operational Integration Drives Synergies:

Upstream and Midstream

- ✓ Co-Development of Marcellus and Utica
- ✓ Installation of just-in-time gathering facilities
- ✓ Expansion of pipeline transmission infrastructure to reach demand markets

Midstream and Downstream

- ✓ Rate-regulated entities reduce operating expenses by sharing common resources
- ✓ Utility and Energy Marketing segments are significant Pipeline & Storage customers

Financial Efficiencies:

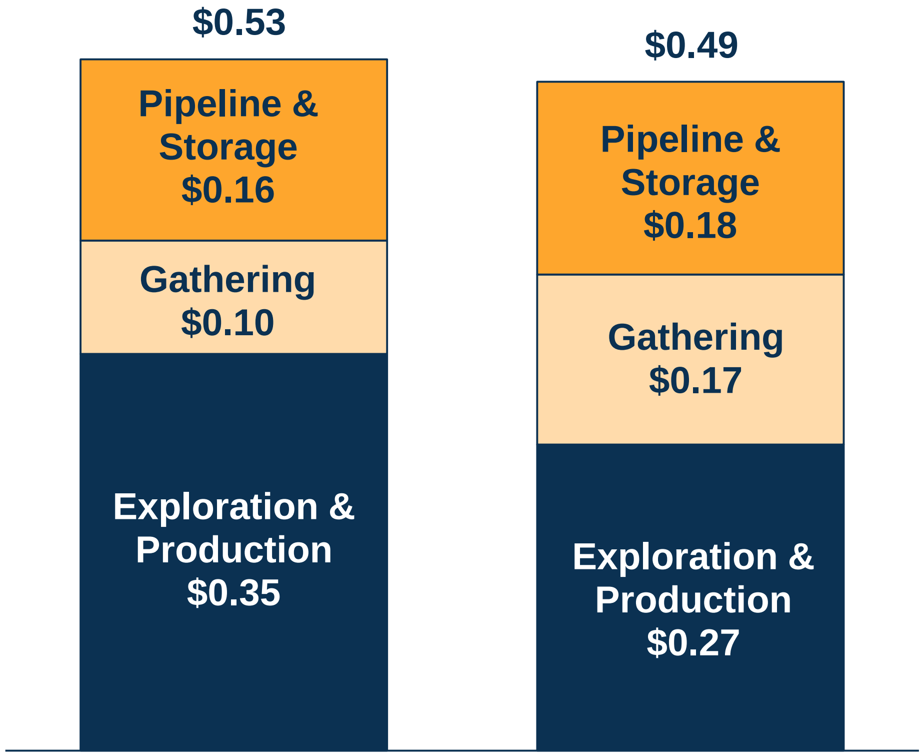
- ✓ Investment grade credit rating
- ✓ Shared borrowing capacity
- ✓ Consolidated income tax return

Fourth Quarter and Fiscal 2018

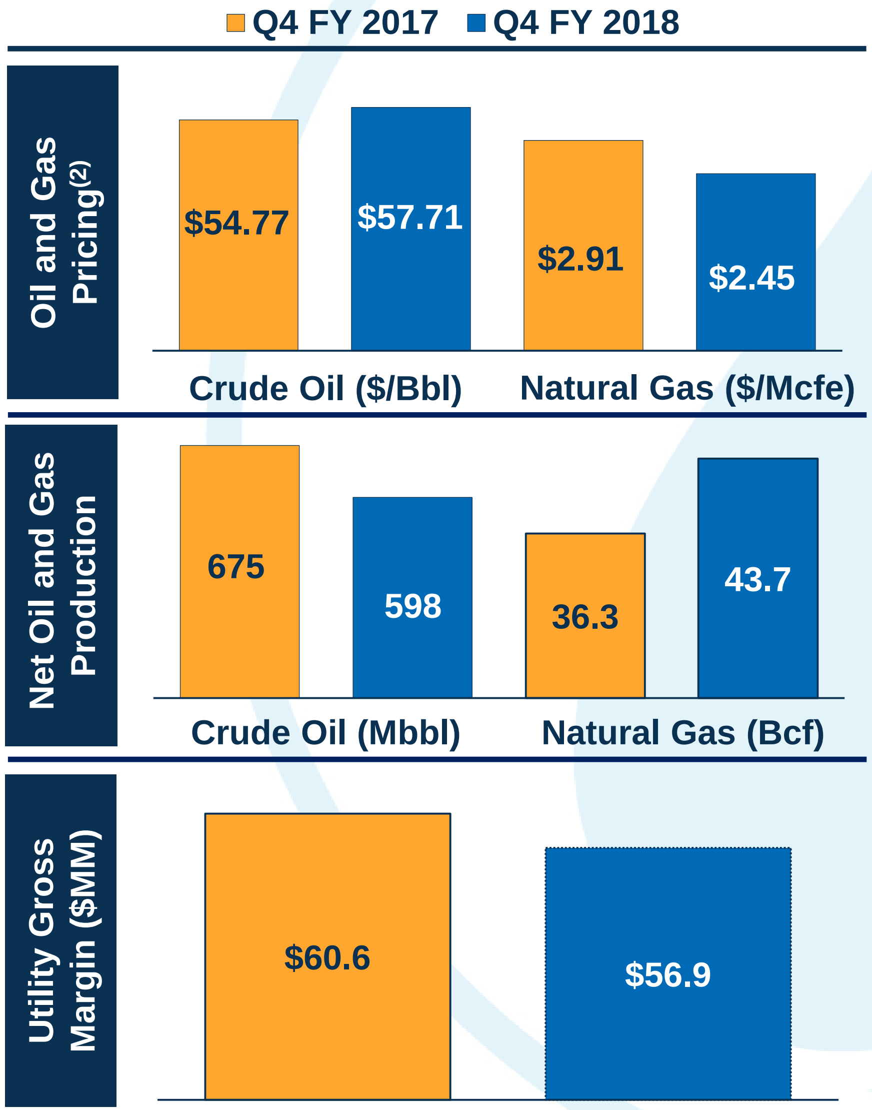
Financial Highlights

Fourth Quarter Fiscal 2018 Results and Drivers

Adjusted Operating Results ($/share)(1)



Q4 FY17	Q4 FY18
Utility: ($0.05)	**Utility**: ($0.08)
All Other: ($0.03)	**All Other**: ($0.05)
Q4 FY17	**Q4 FY18**



Drivers

- ↑ Oil Prices
- ↓ Natural Gas Prices
- ↑ Natural Gas Production
- ↓ Oil Production (sale of Sespe field)
- ↓ Regulatory Adjustment (non-recurring)

(1) Adjusted Operating results of $0.53 for Q4 Fiscal 2017 and $0.49 for Q4 Fiscal 2018 include operating results of Energy Marketing and Corporate & All Other segments. See slide 63 for Reconciliation of Adjusted Operating Results to Earnings Per Share.
(2) Realized price after hedging.

Fiscal 2018 Highlights

Adjusted Operating Results	$3.34 per share(1)	Up from $3.30 per share (operating results) in FY17(1)
Dividend	$1.70 per share	Grew shareholder distribution for 48th consecutive year
Production	178.1 Bcfe	Up from 173.5 Bcfe in FY17; highest output in NFG history
Proved Reserves	2.52 Tcfe	Up 17% vs. FY17; replaced 361% of production
Gathering Segment Throughput	198.4 Bcfe	Up from 194.9 Bcfe in FY17; highest throughput in NFG history
Pipeline & Storage Revenues	$300.3 Million	Up from $294.4 million in FY17
Utility Safety Investments	$70 Million	Utility segment capital expenditures on pipeline replacement and modernization

(1) A reconciliation of adjusted operating results to GAAP earnings is included at the end of this presentation.

Earnings Guidance

Key Guidance Drivers		FY2018 Adjusted Operating Results: $3.34 /share(1)	FY2019 Earnings Guidance: $3.35 to $3.65 /share
Non-regulated Businesses – *Exploration & Production*, *Gathering*	↑	**Production & Gathering Throughput**	▪ Seneca Net Production: 210 to 230 Bcfe ▪ Gathering Revenues: $130-140 million
	↓	**Realized natural gas prices (after-hedge)**	▪ Natural Gas: ~$2.40/Mcf(2) *(vs. $2.52/Mcf in FY 2018)*
	↑	**Realized oil prices (after-hedge)**	▪ Crude Oil: ~$61/Bbl(3) *(vs. $58.66/Bbl in FY 2018)*
Regulated Businesses – *Pipeline & Storage*, *Utility*	↓	**Pipeline & Storage Revenues**	▪ ~$285 million in revenues *(expected decrease primarily due to expiration of contract on Empire system)*
	↔	**Utility Operating Income**	▪ Guidance assumes normal weather; modestly higher gross margin expected to be offset by cost inflation
Tax Reform	↑	**Lower effective tax rate**	▪ Effective tax rate ~25% (federal rate 21%)

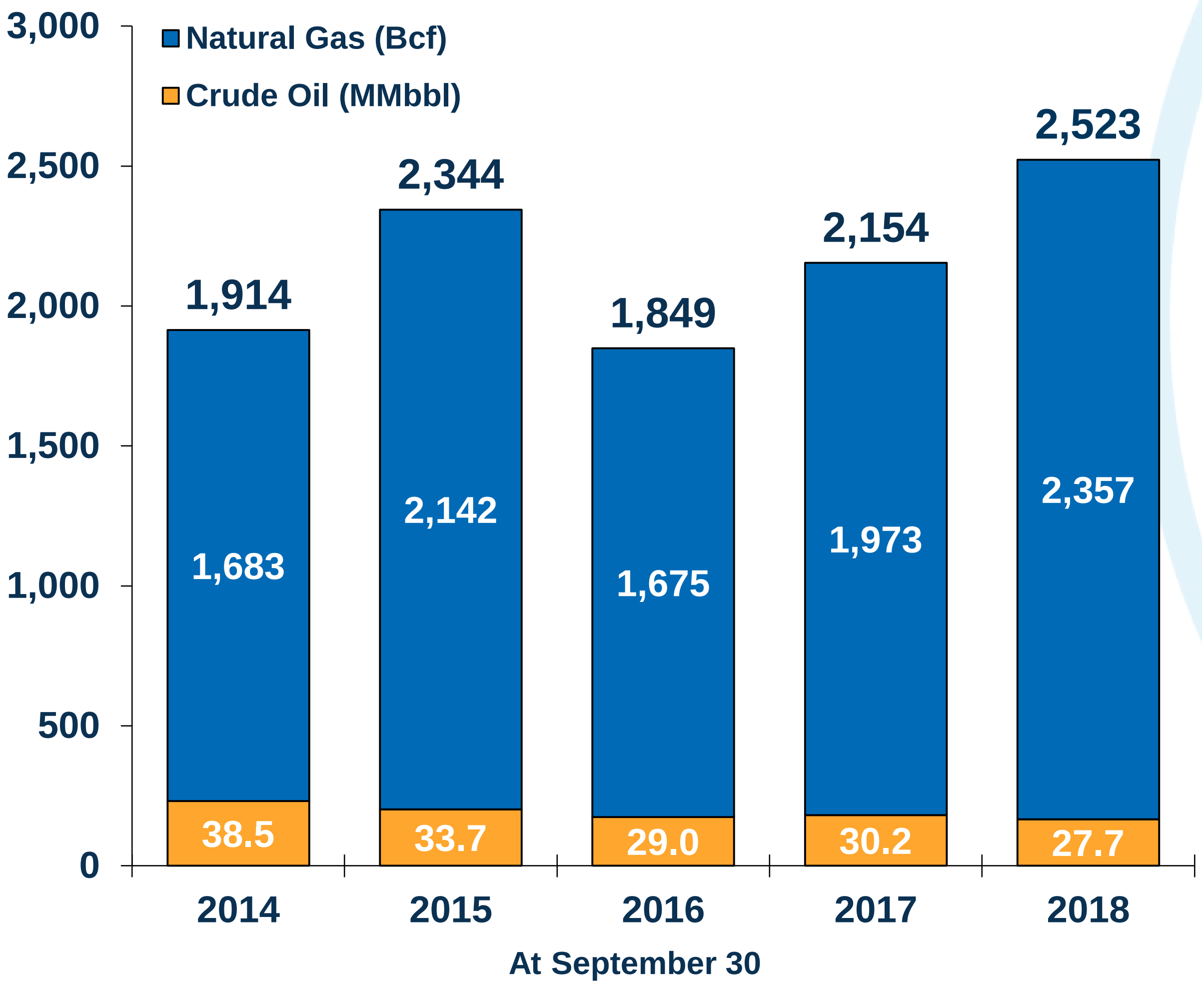
(1) Excludes the $103.5 million, or $1.20 per share, reduction in tax expense due to the remeasurement of deferred taxes resulting from the 2017 Tax Reform Act. See non-GAAP disclosure on slide 63 of this presentation.
(2) Assumes NYMEX natural gas pricing of $3.00/MMBtu (winter) and $2.65/MMBtu (summer) and basin spot pricing of $2.50/MMBtu (winter) and $2.00/MMBtu (summer) for FY19, and reflects the impact of existing financial hedge, firm sales and firm transportation contracts.
(3) Assumes NYMEX (WTI) oil pricing of $70.00/Bbl and California-MWSS pricing differentials of 100% to WTI for FY19, and reflects impact of existing financial hedge contracts.

Exploration & Production and Gathering Overview

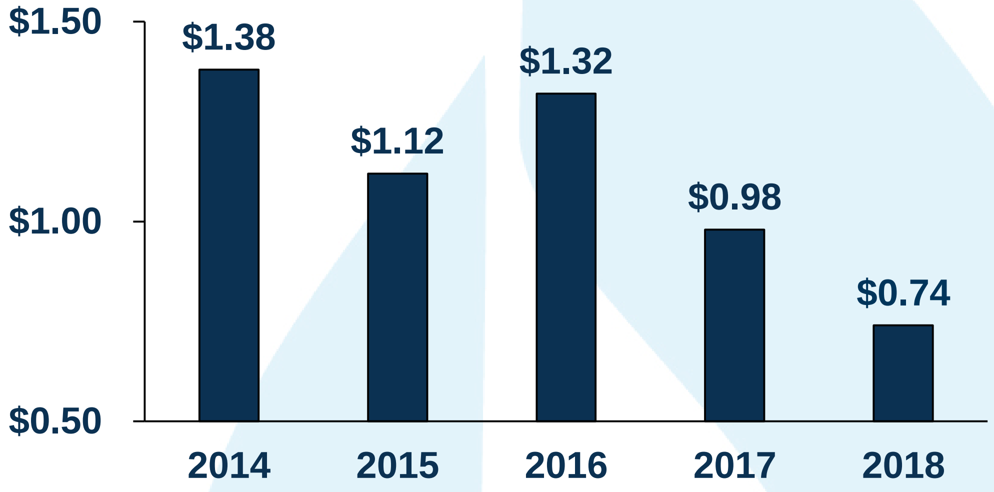
Seneca Resources Company, LLC ~ National Fuel Gas Midstream Company, LLC

Proved Reserves

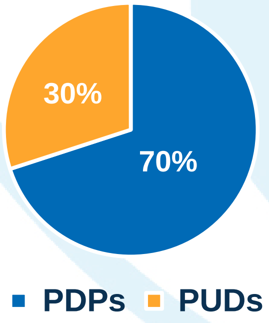
Total Proved Reserves (Bcfe)



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



Fiscal 2018 Proved Reserves Stats

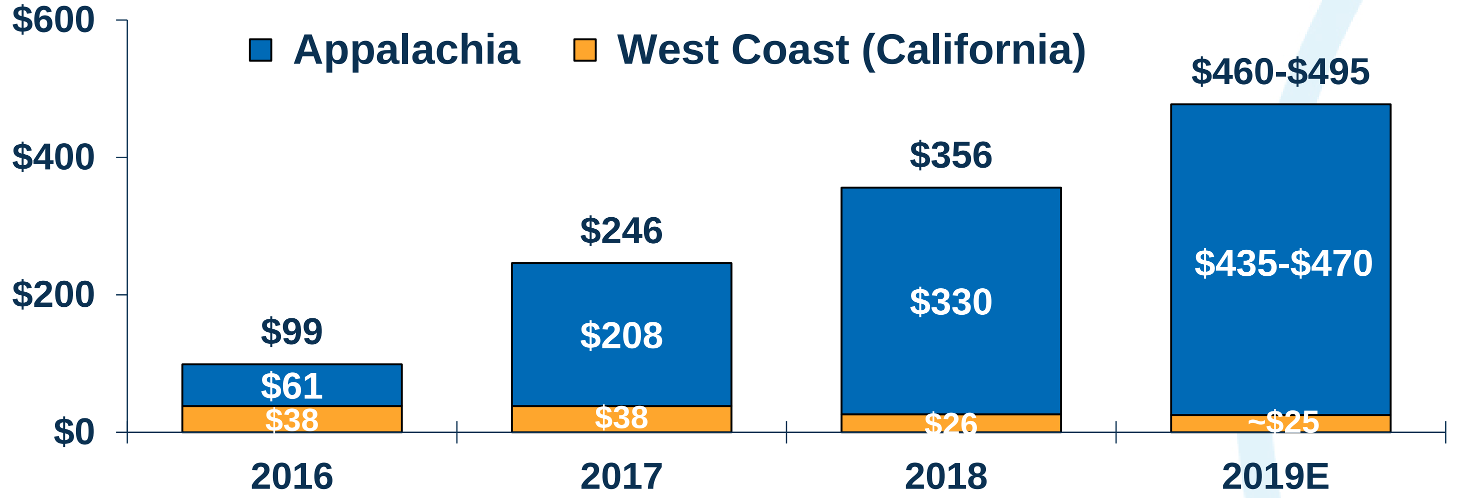


- 361% Reserve Replacement Rate
- Seneca Drill-bit F&D = $0.66/Mcfe(1)
- Appalachia Drill-bit F&D = $0.65/Mcfe(1)

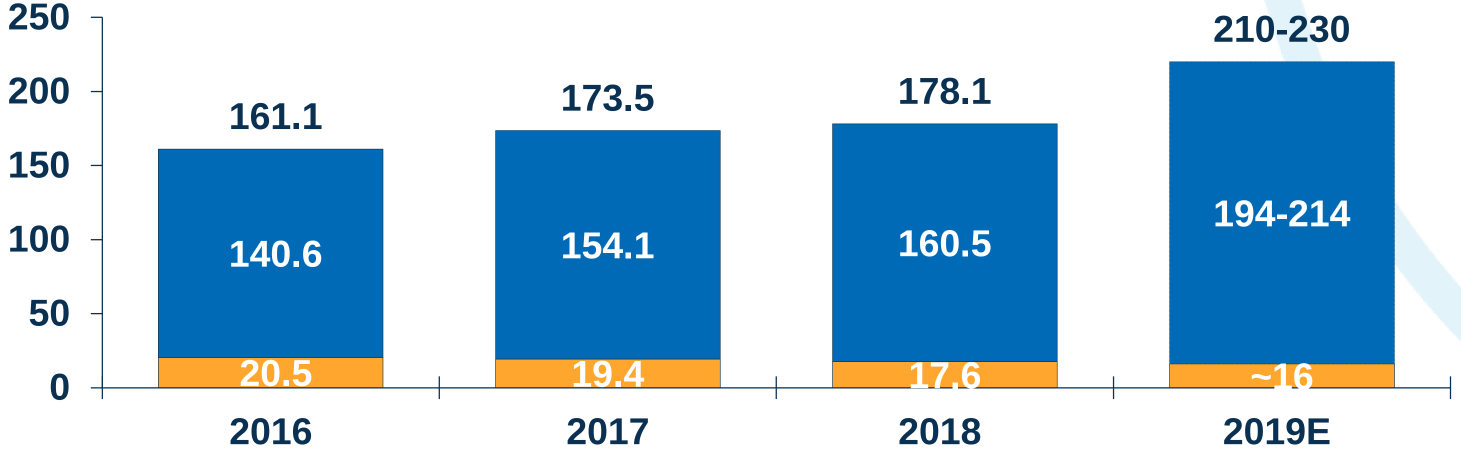
(1) Seneca “Drill-bit” finding and development (“F&D”) costs exclude the impact of reserve revisions.

Growing Production within Disciplined Capital Program

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



E&P Net Production (Bcfe)



Near-Term Growth Strategy

- **3 rig** development program, with new rig added in WDA to focus on Utica
- **15-20% net production growth** expected through fiscal 2022
- New **EDA Utica development** with production starting in fiscal 2019
- Utilize new **Atlantic Sunrise** firm transportation capacity
- Layer-in firm sales to take advantage of **attractive regional pricing**
- Gross production growth will benefit NFG's Gathering segment
- Minimal capital investment in California to generate significant cash flow

(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.

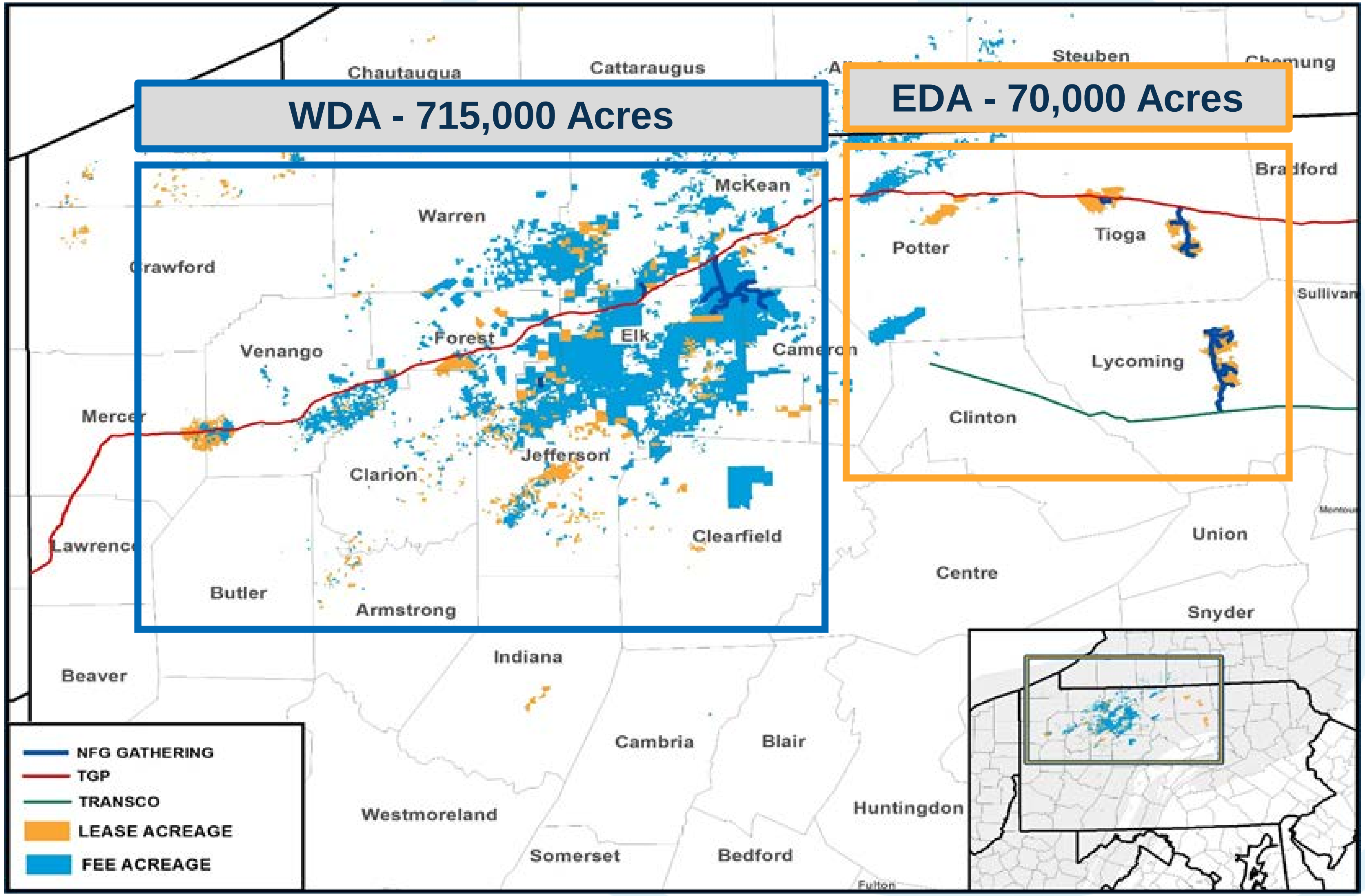
Significant Appalachian Acreage Position

Western Development Area (WDA)

- Current gross production: ~341 MMcf/d
- Large inventory of Marcellus & Utica locations 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: ~315 MMcf/d
- Mostly leased (16-18% royalty) with no significant near-term lease expirations
- ~90 remaining Marcellus & Utica locations economic at ~$1.80/Mcf
- Additional Utica & Geneseo potential across position



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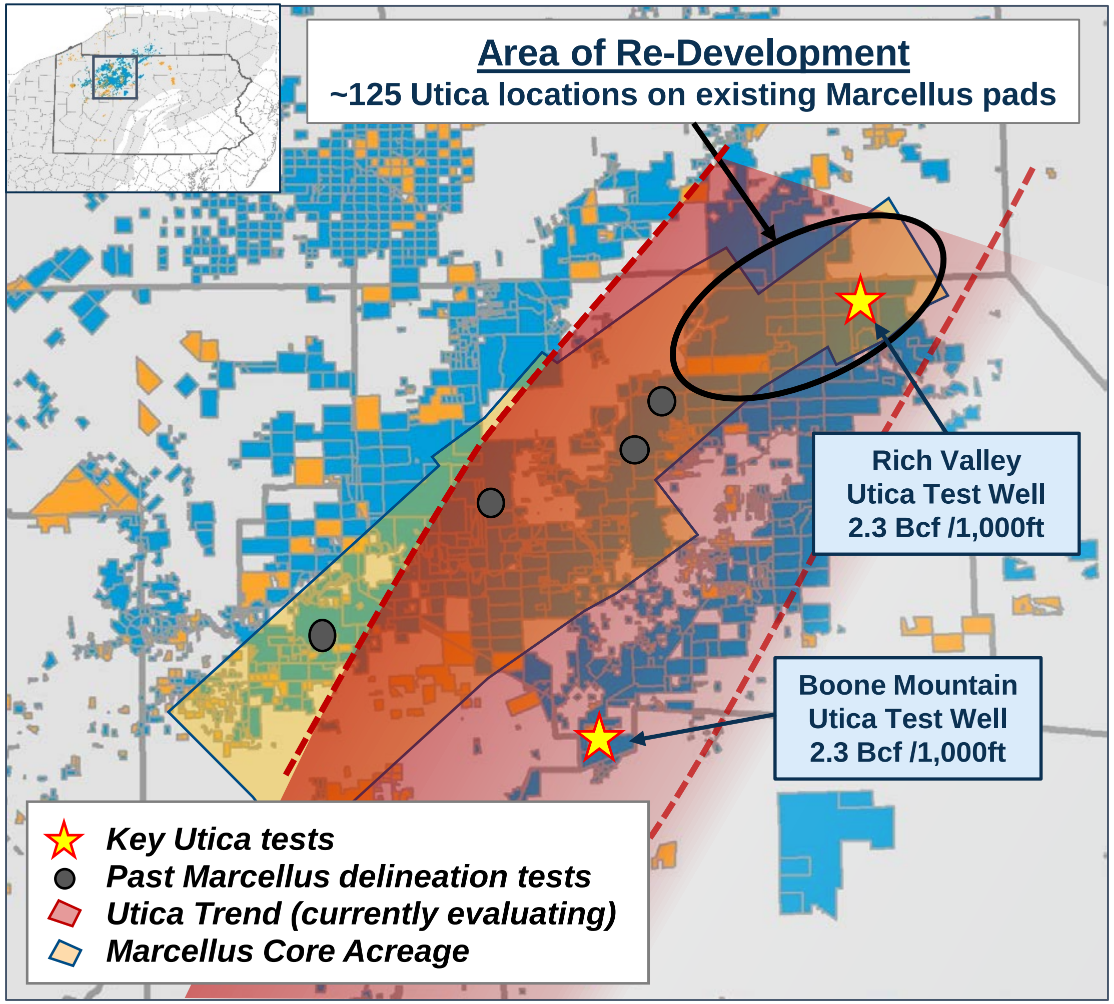
Western Development Area

Marcellus Core Acreage vs. Utica Appraisal Trend[(1)]



WDA Highlights

- ✓ **Large well inventory economic at ~$2.00 /Mcf**
  - Marcellus Shale: **600+** well locations remaining / 200,000 acres
  - Utica Shale: **500+** potential locations across Utica trend / evaluating extent of prospective acreage[(2)]
- ✓ **Fee acreage (no royalty) enhances economics and provides development flexibility**
- ✓ **Addition of 2nd WDA drilling rig in Q3 FY18 focused on redevelopment of Clermont-Rich Valley acreage for Utica**
- ✓ **Use of existing gathering, pad, and water infrastructure for Utica drives increased Appalachian program returns**
- ✓ **Highly contiguous position drives best in class well costs**
- ✓ **Utica test results on trend with other Utica wells in NE Pa.**
- ✓ **Long-term firm contracts support growth**

(1) The Utica Shale lies approximately 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.

WDA Utica Appraisal Results and Initial Type Curve

WDA Utica Appraisal Update

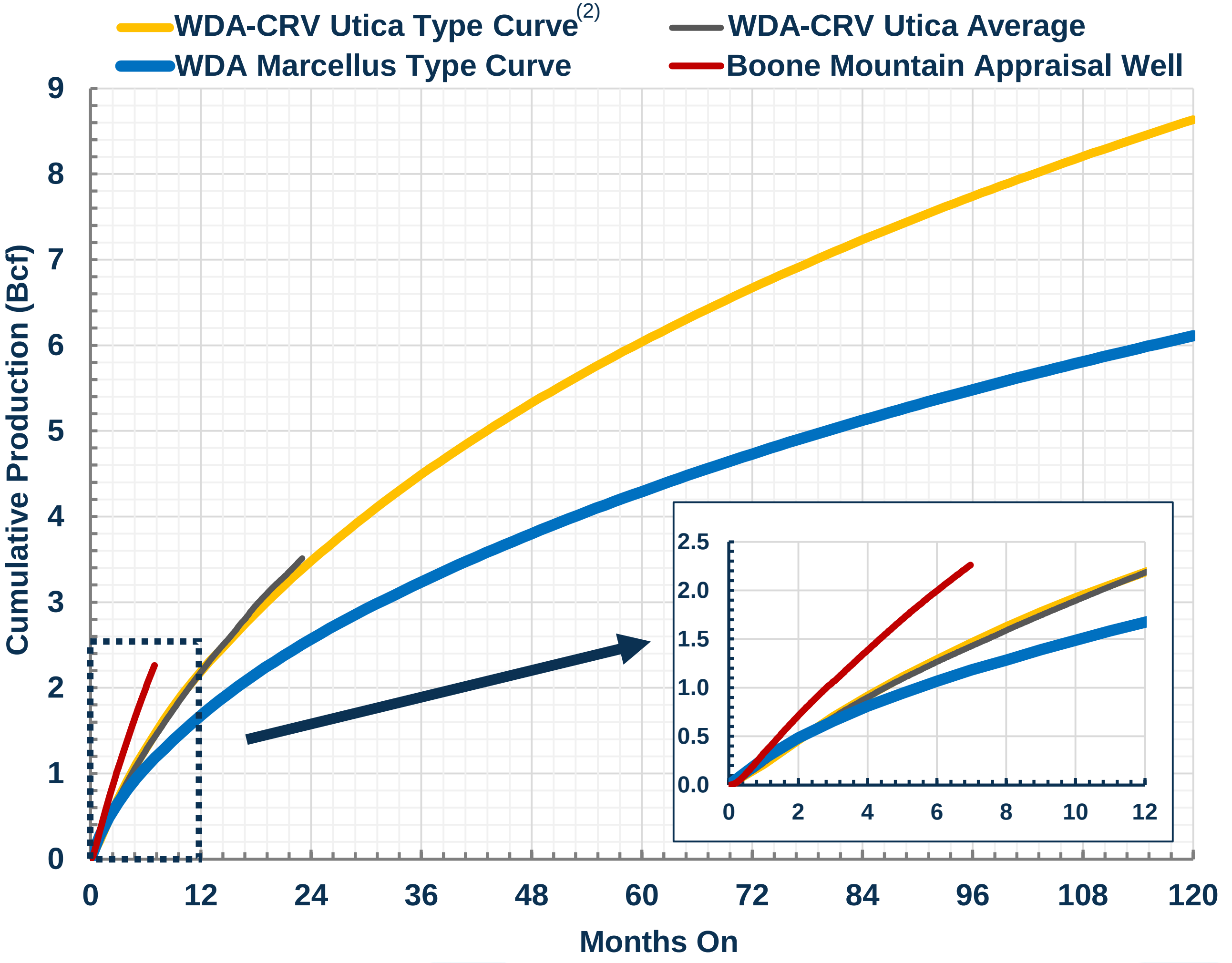
- ✓ Tested / producing from 10 Utica wells in WDA-CRV
- ✓ Higher pressure significantly enhances well productivity (Utica ~5,000' deeper than Marcellus)
- ✓ Drawdown management is critical: restricted drawdown improves well EURs
- ✓ Early production declines much shallower vs. Marcellus

WDA Economics

	EUR Bcf/1000'	Well Cost $M/1000'	IRR % $2.25	Break-even 15% IRR[(1)]
Utica - CRV	1.7	$892	23%	$1.97
Marcellus	1.0 – 1.1	$637	20%	$2.04

(1) Internal Rate of Return (IRR) is pre-tax and includes estimated well costs under current cost structure, LOE, and anticipated gathering tariffs.
(2) Initial WDA-CRV Utica type curve based on production results and reservoir expectations from the first 5 appraisal wells in the WDA-CRV area.

WDA-CRV Wells Normalized to 9,000'



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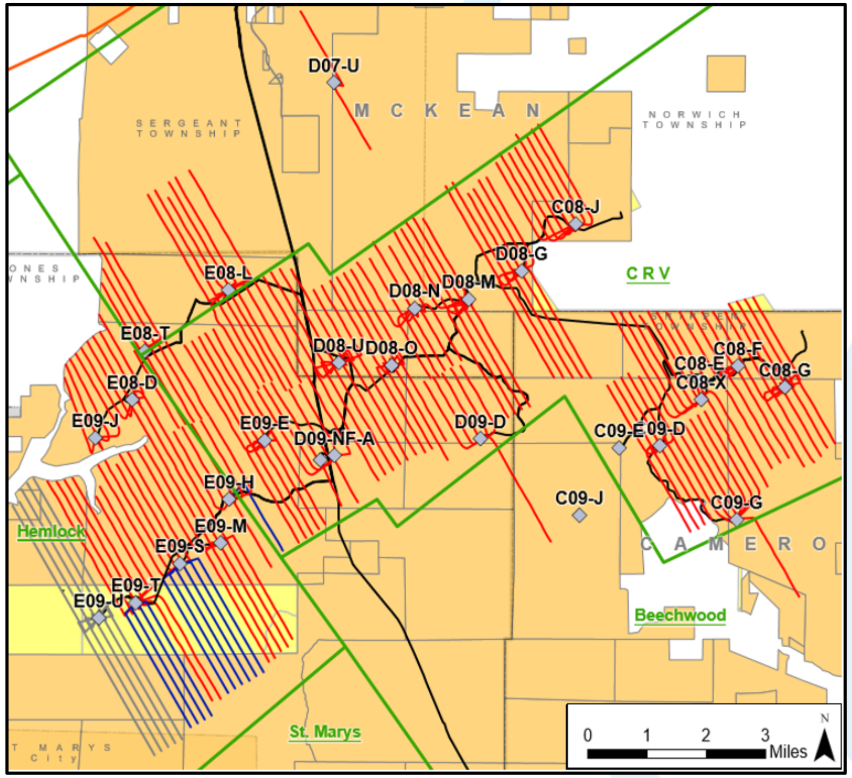
Transitioning to Utica Development in CRV

CRV Utica Development Utilizes Existing Pad, Water, and Gathering Infrastructure to Drive Economics

CRV Utica Transition Plan

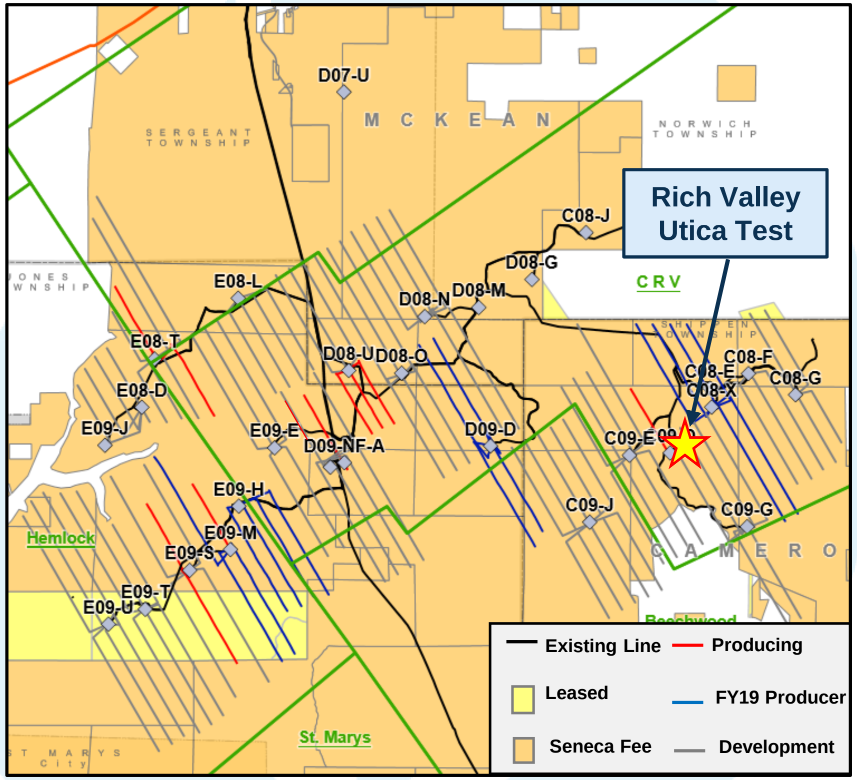
1) **Finish Marcellus Pads in Development**
   - Drill 20 / complete 20 Marcellus wells (100% Seneca)
2) **Optimize Utica D&C design**
   - Drill additional Utica optimization wells off Marcellus pads (currently 10 producing wells)
   - Optimization to include:
     - Well spacing
     - Completion design / stage spacing
     - Landing zone targets
3) **Transition to Utica development in FY19**
   - Continue shift toward multi-well Utica pads
   - Tailor development plan to use existing pad, water and gathering infrastructure

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



- ✓ Average CRV Marcellus Production: 287 Mcf/d
- ✓ Rem. Avg. EUR 1.0-1.1 Bcf / 1,000 lat ft.
- ✓ Rem. Avg. Well Costs = $637/lat ft.

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



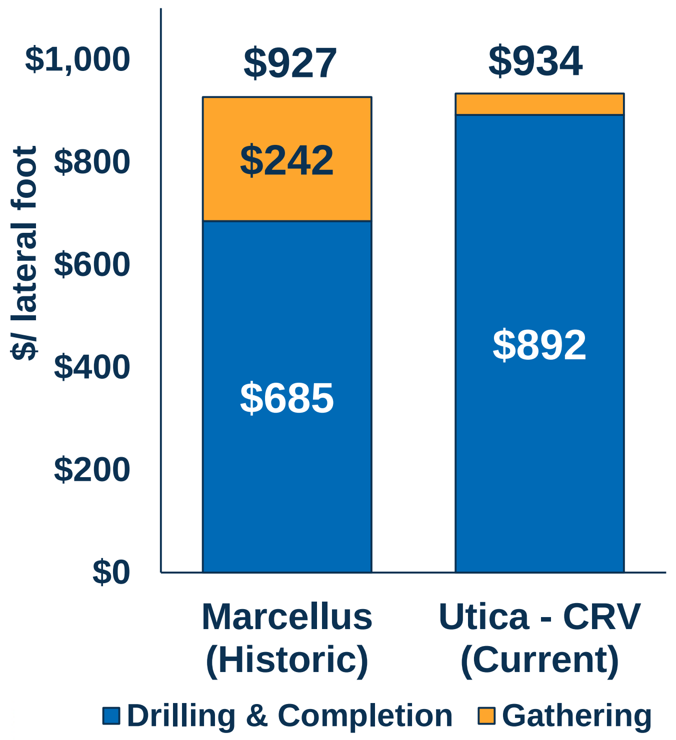
- ✓ 125+ locations on existing Marcellus pads
- ✓ Est. EURs 1.7 Bcf / 1,000 lat ft.
- ✓ Est. Development Well Costs = $892/lat ft.

Limited New Infrastructure Needed to Support Production Growth

Leveraging Existing Gathering, Water and Pad Infrastructure Enhances Returns

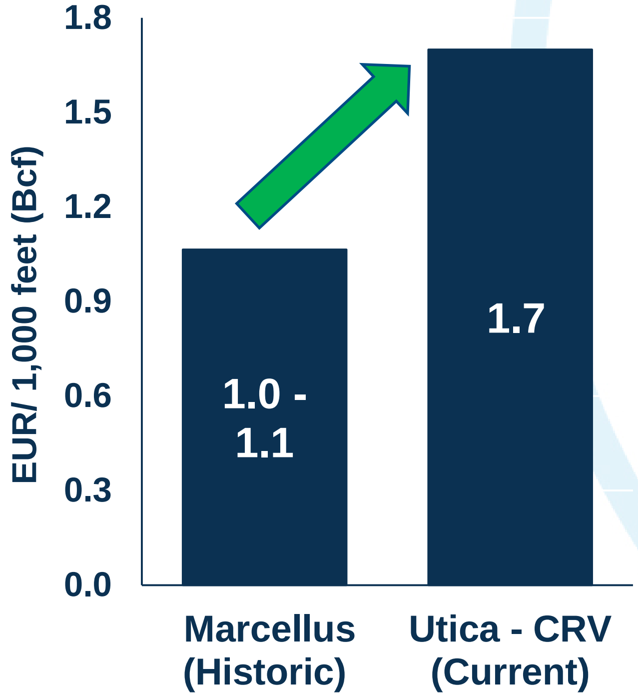
WDA Well Costs(1)

Total cost per well expected to marginally increase



WDA EURs

60-70% EUR increase expected per well



WDA Consolidated Economics

The addition of a 3rd rig is incremental to returns, and provides economies of scale and significant operational flexibility

10+% IRR Uplift Expected

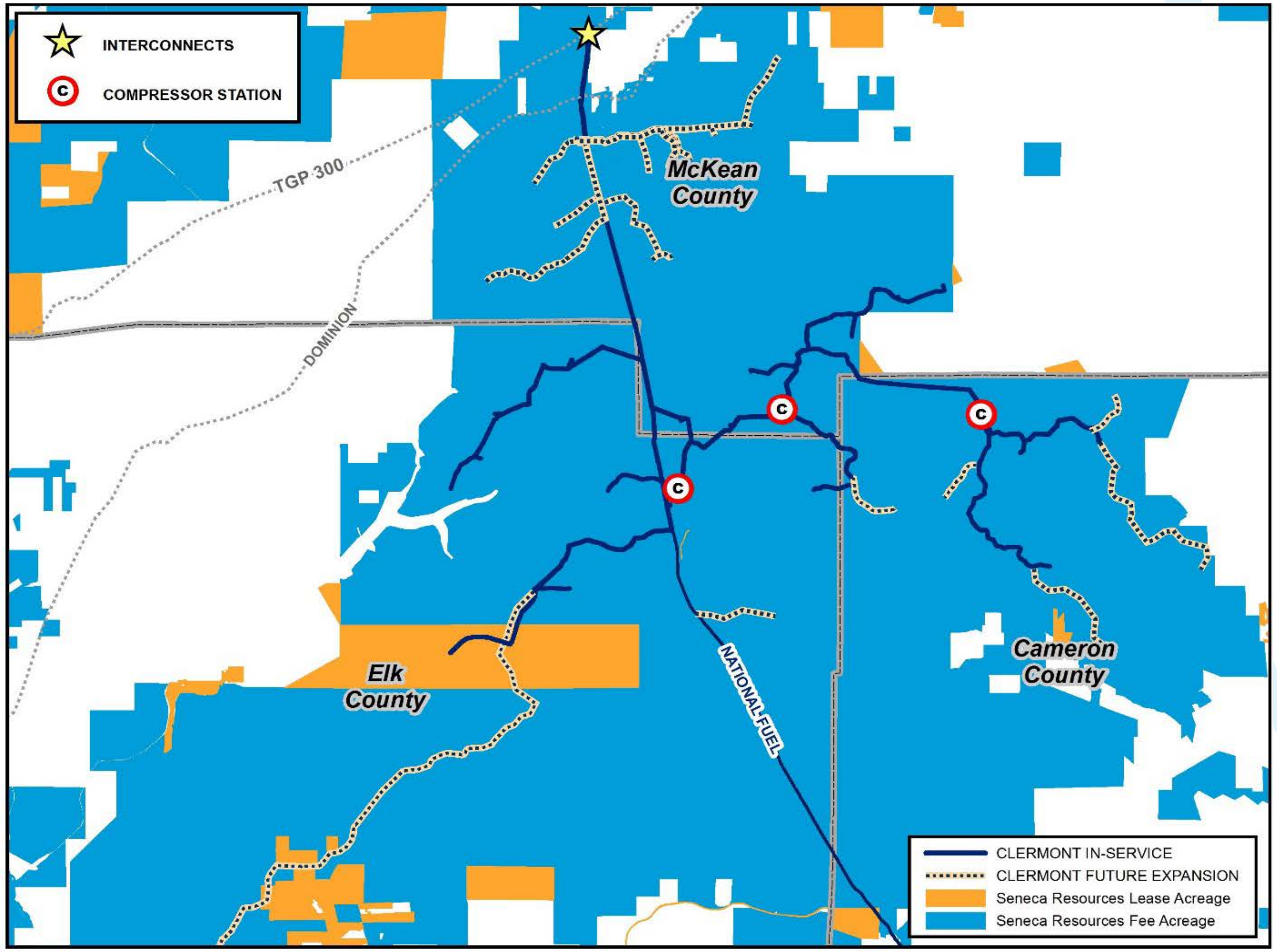
At a $2.25 netback price, consolidated Seneca WDA and Gathering IRR is approximately 35%, an uplift of ~11% over standalone Seneca WDA economics(2)

(1) WDA Marcellus well costs reflect drilling, completion and gathering costs for the 166 drilled and completed wells. WDA Utica well costs reflect expected drilling, completion and gathering costs for the ~125 well locations in area of redevelopment.
(2) Internal Rate of Return for Seneca WDA includes estimated well costs under current cost structure, and anticipated LOE and Gathering costs. Internal Rate of Return for Seneca WDA and Gathering includes expected gathering capital expenditures through FY 2022, well costs under current cost structure, and non-gathering LOE.

Integrated Development – WDA Gathering System

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: $297 million

Future Build-Out

- FY 2019 CapEx: $10MM - $20MM
- Modest gathering pipeline and compression investment required to support Seneca's transition to Utica 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

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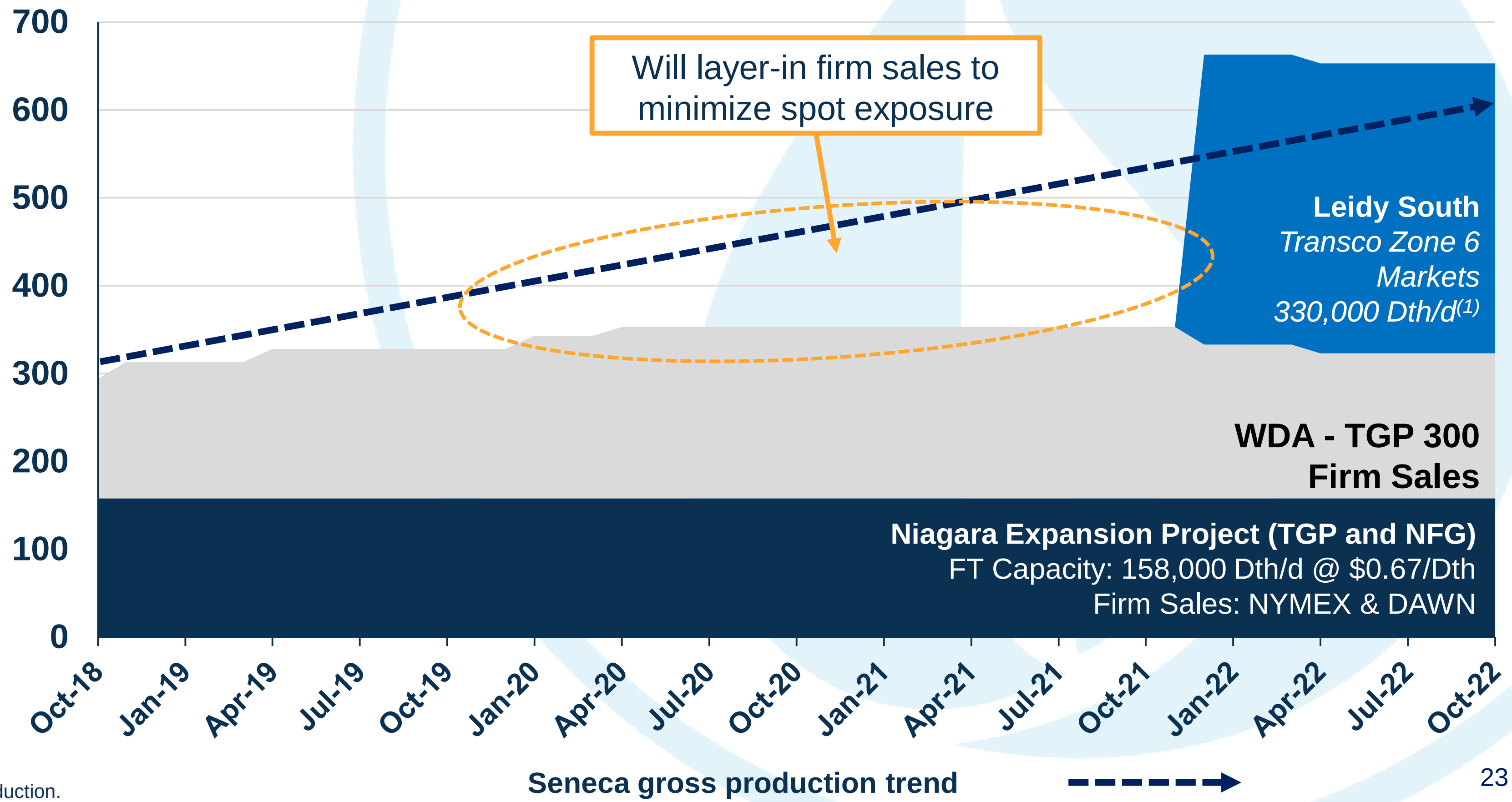
WDA Firm Transportation and Sales Capacity

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

WDA Gas Marketing Strategy

- ✓ 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
- ✓ Leidy South will provide additional capacity to premium markets (Transco Zone 6)

WDA Contracted Firm Transport and Gross Sales Volumes (MDth/d)



(1) Portion of Transco Project capacity will likely be utilized by EDA Lycoming County production.

Eastern Development Area

EDA Highlights

1 DCNR Tract 007 (Tioga Co., Pa)

- Utica development resumed in third quarter fiscal 2018
- 43 remaining Utica locations economic at ~$1.80 /Mcf
- Gathering Infrastructure: NFG Midstream Wellsboro
- Marcellus Shale expected to provide ~60 additional locations

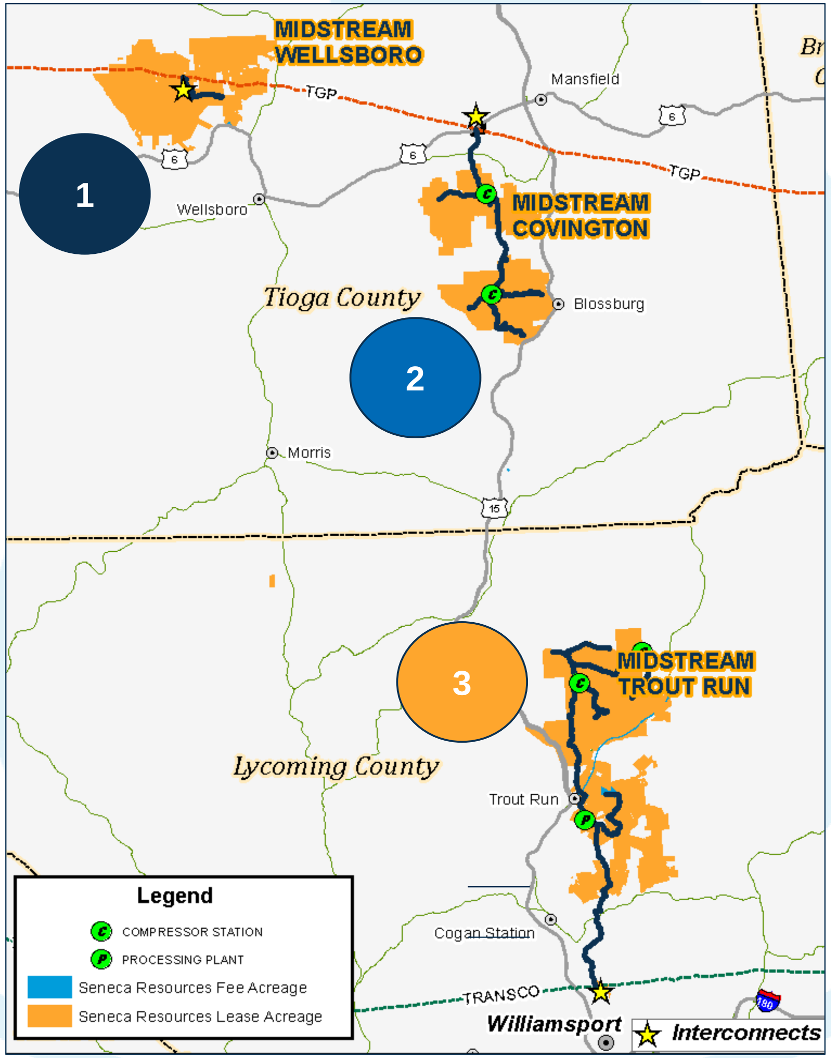
2 Covington & DCNR Tract 595 (Tioga Co., Pa.)

- Marcellus locations fully developed (gross daily production of ~97 MMcf/d)
- Gathering Infrastructure: NFG Midstream Covington
- Opportunity for future Utica appraisal

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

- ~50 remaining Marcellus locations economic at ~$1.50 /Mcf
- Atlantic Sunrise capacity (189 MDth/d) online as of early October 2018
- Gathering Infrastructure: NFG Midstream Trout Run
- Geneseo Shale expected to provide 100-120 additional locations

EDA Acreage – 70,000 Acres

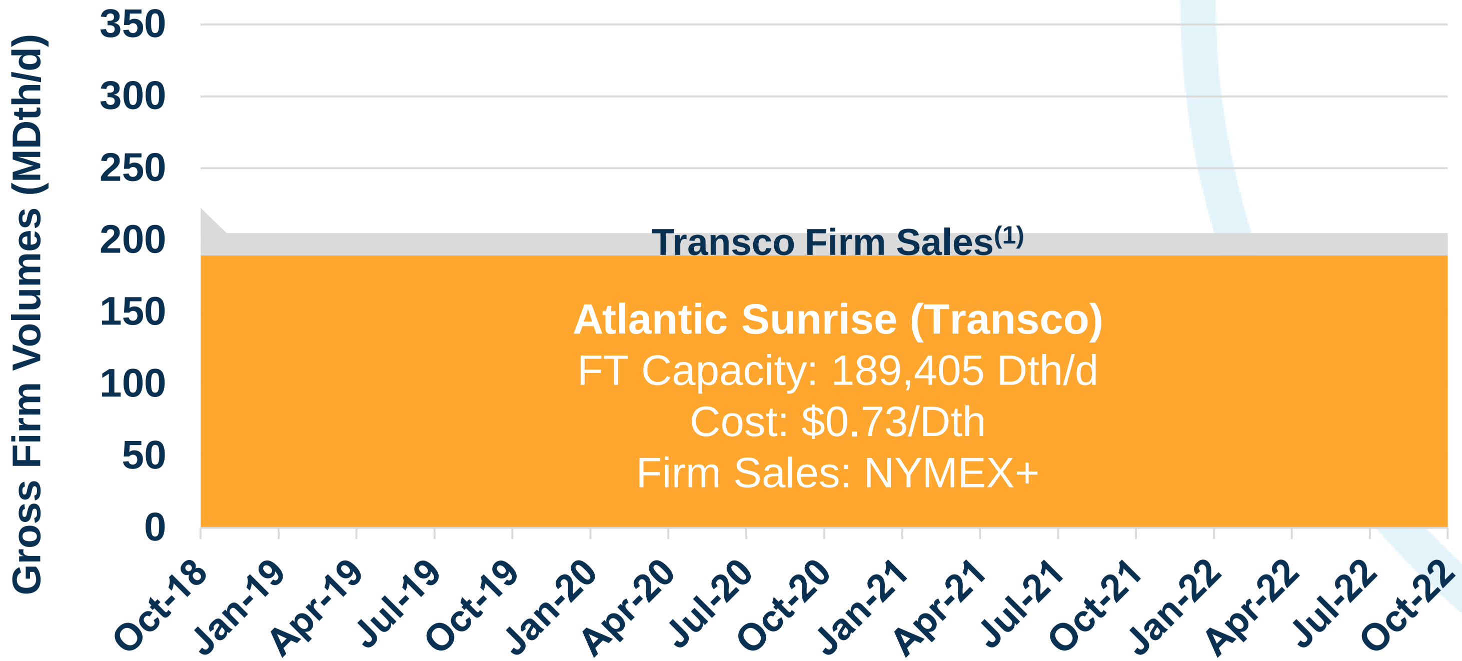


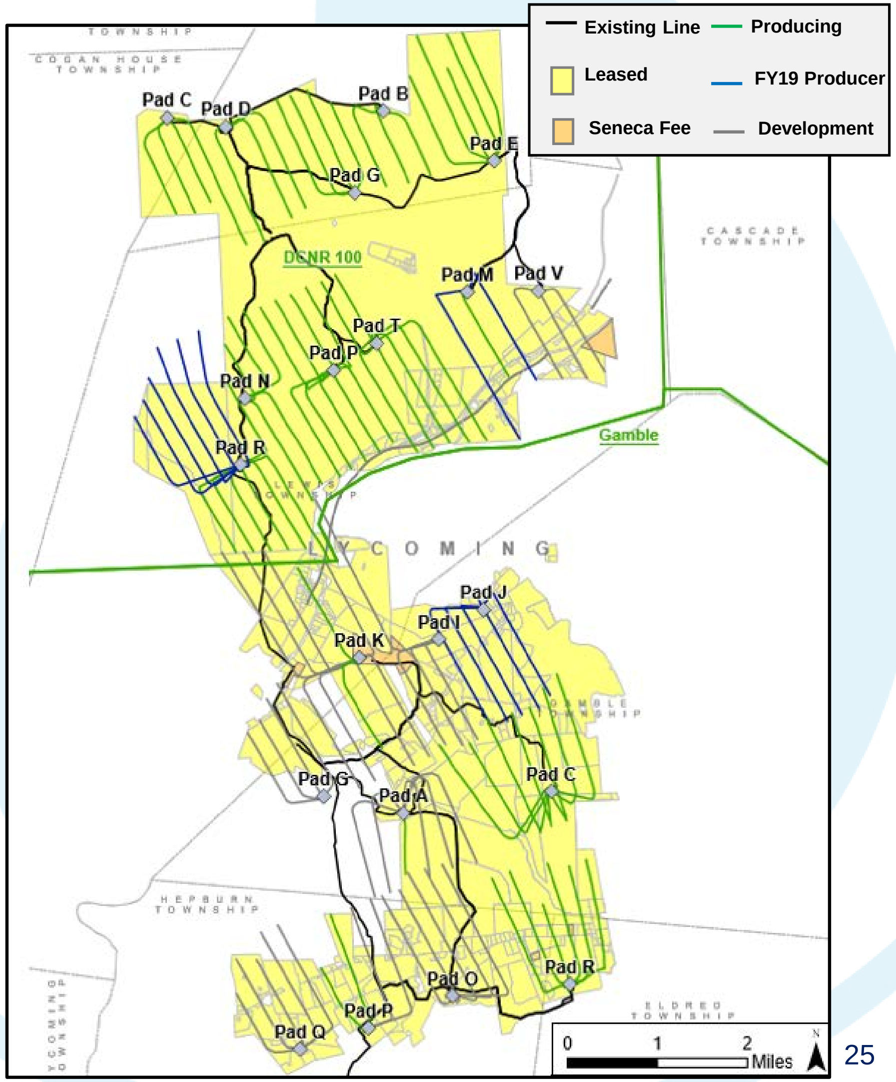
EDA Marcellus: Lycoming County Development

Marcellus Development in Lycoming County has Resumed in Connection with Atlantic Sunrise

- ✓ Prolific Marcellus acreage with peer leading well results
- ✓ ~50 remaining Marcellus locations economic at ~$1.50 /Mcf
- ✓ Near-term development focused on filling Atlantic Sunrise capacity

EDA – Transco Firm Contracts





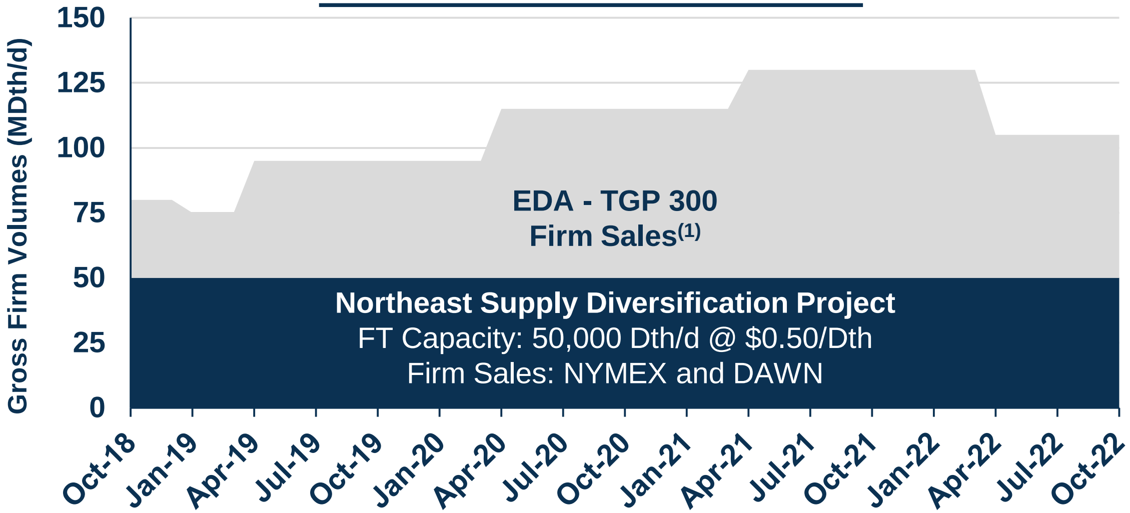
(1) Includes physical fixed price and NYMEX-based firm sales contracts that do not carry any additional transportation costs.

EDA Utica: Tioga County Development

Utica Development in Tioga County – Tract 007 Development Resumed in Q3 Fiscal 2018

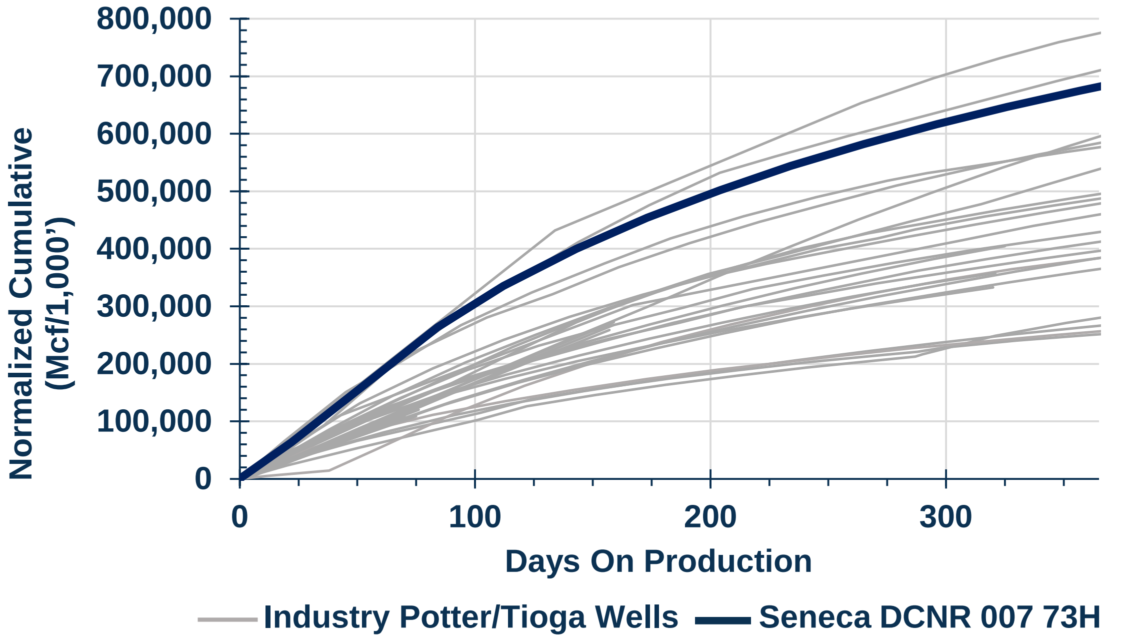
- ✓ **Inventory:** 43 locations economic at ~$1.80 /Mcf
  - Targeting to grow production by 100 to 150 MDth/d by fiscal 2020
- ✓ **Expected Development Costs:** $1,011 per lateral ft.
- ✓ **Gathering Infrastructure:** NFG Midstream Wellsboro
  - Modest build-out required to connect to TGP 300
- ✓ **Sales/Takeaway Strategy:** Layer-in firm sales with shippers holding capacity on TGP 300

EDA – TGP 300 Firm Contracts



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



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

Integrated Development – EDA Gathering Systems

Gathering Segment Supporting Seneca's EDA Production & Future Development

Wellsboro Gathering System

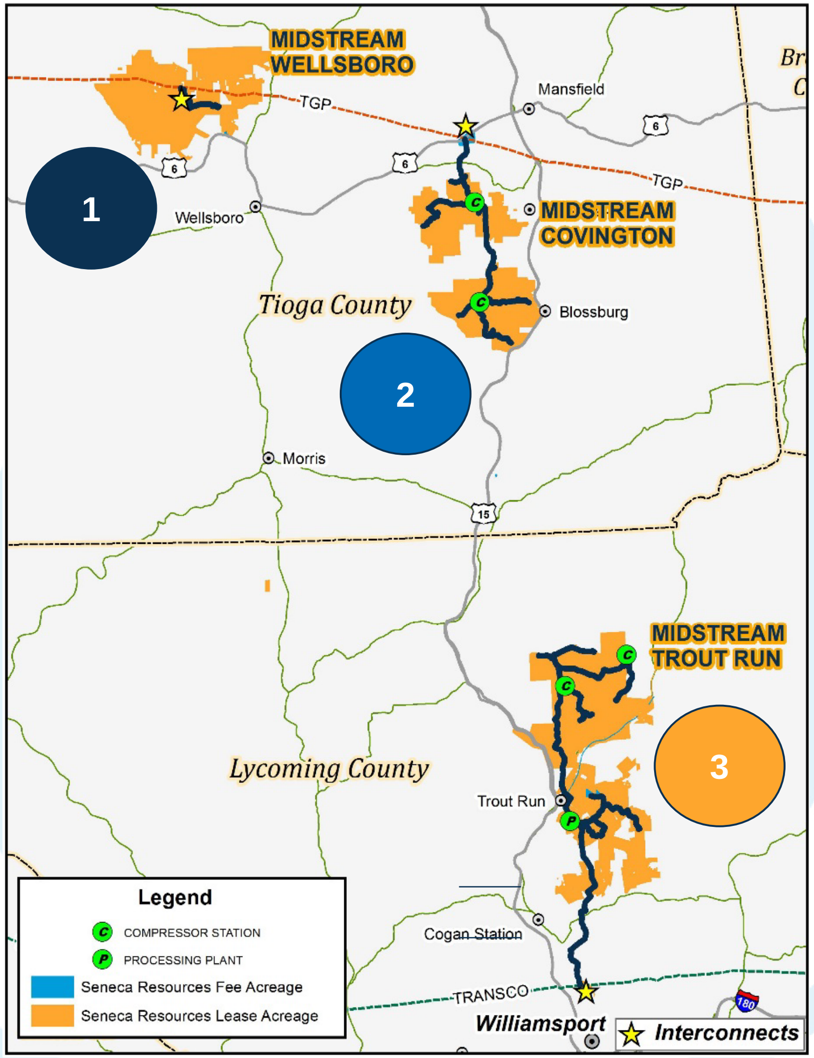
- **Total Investment (to date):** ~$9 million
- **FY 2019 Estimated Capital Expenditures:** $8 MM - $15 MM
- **Capacity:** up to 200,000 Dth per day (Interconnect w/ TGP 300)
- **Production Source:** Seneca Resources – Tioga Co. (DCNR Tract 007)

Covington Gathering System

- **Total Investment (to date):** ~$46 million
- **FY 2019 Estimated Capital Expenditures:** $1 MM - $2 MM
- **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

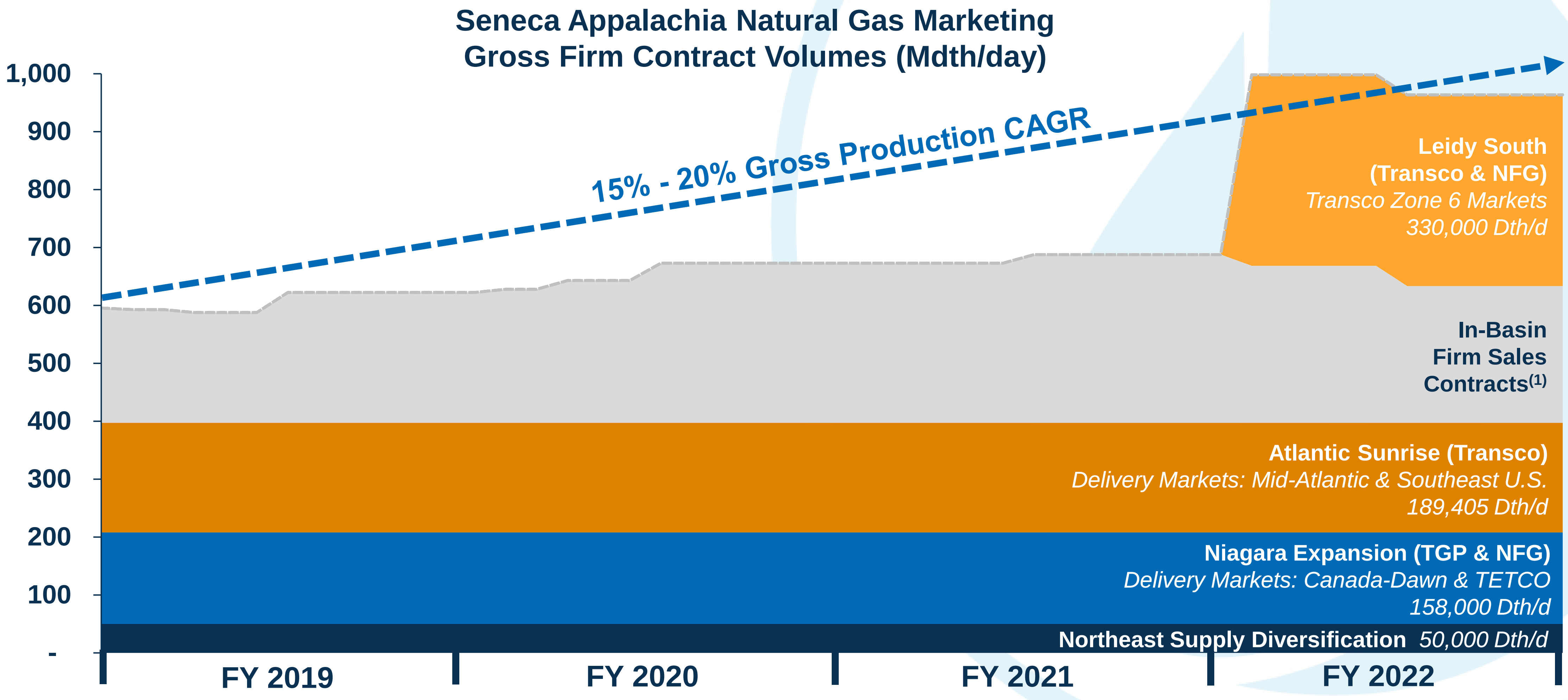
- **Total Investment (to date):** ~$204 million
- **FY 2019 Estimated Capital Expenditures:** $30 MM - $50 MM
- **Capacity:** 466,000 to 585,000 Dth per day (Interconnect w/ Transco)
- **Production Source:** Seneca Resources – Lycoming Co. (DCNR Tract 100 and Gamble)
- Future third-party volume opportunities



National Fuel

Long-term Contracts Supporting Appalachian Growth

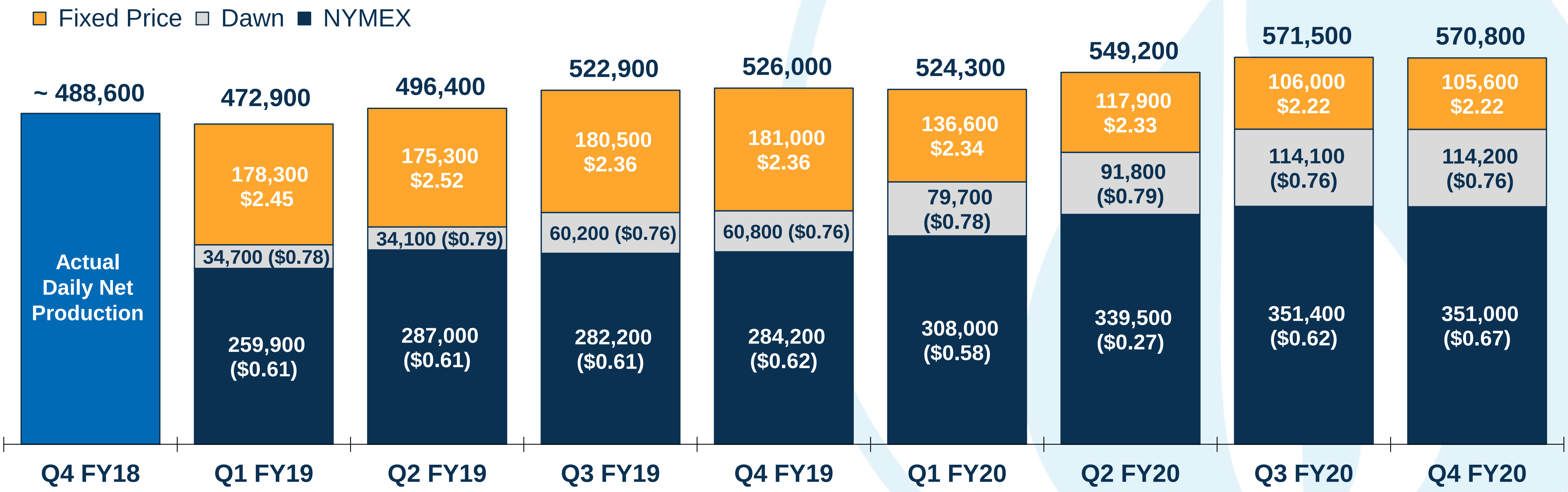
Seneca continues to layer-in firm sales contracts with attractive realizations to lock-in drilling economics and minimize spot exposure ahead of firm transportation in-service dates



(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

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

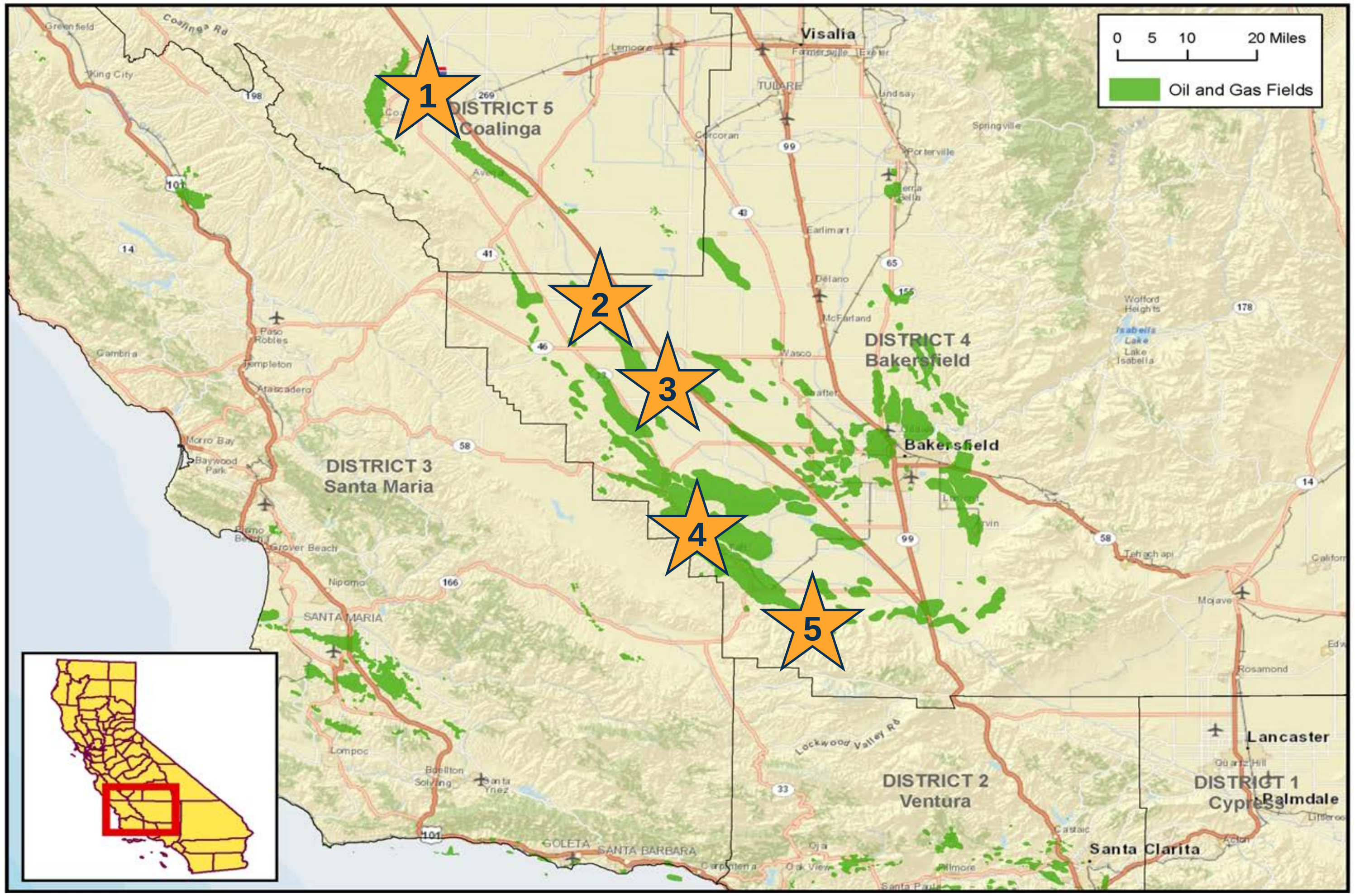


Gross Firm Sales Volumes (Dth/d)	606,900	616,200	644,300	637,300	635,400	659,300	674,300	667,000

(1) Values shown represent the weighted average fixed price or contracted fixed differential relative to NYMEX (netback price) less any associated transportation costs.

California Oil

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

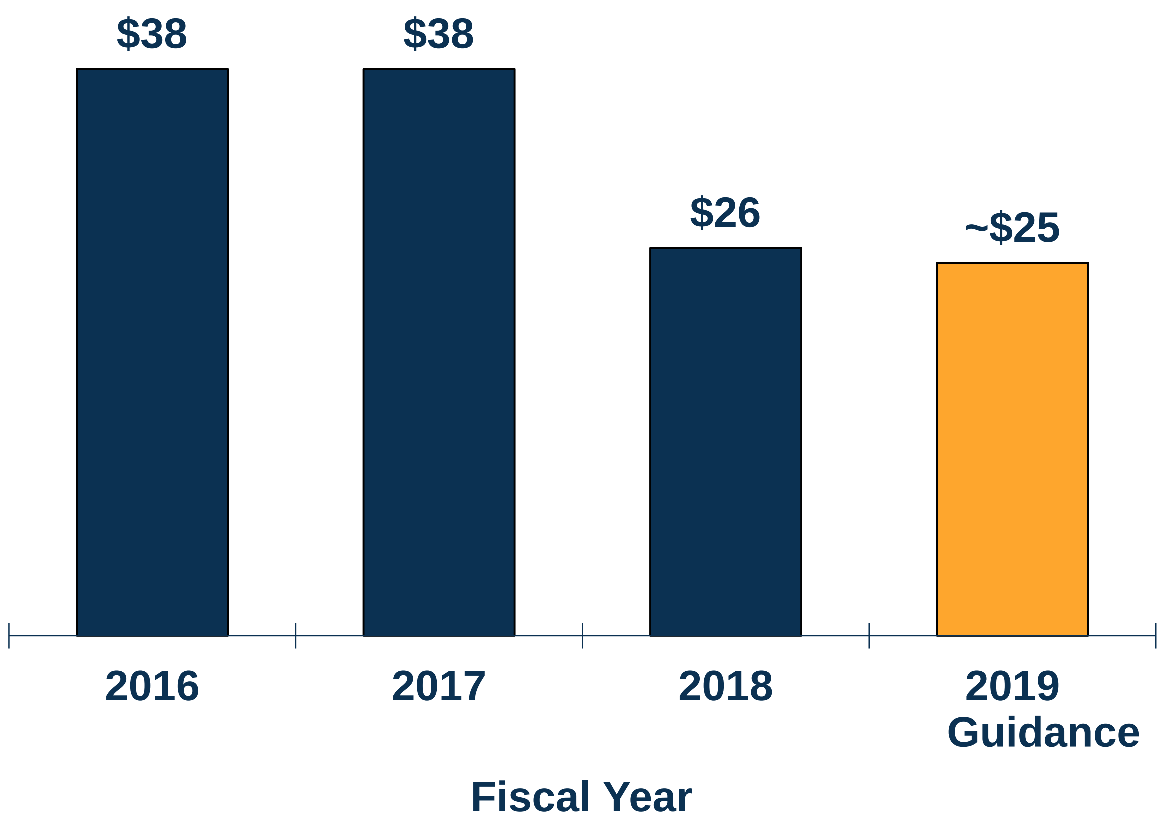


	Location	Formation	Production Method	FY18 Daily Production *(net Boe/d)*
1	East Coalinga	Temblor	Primary	512
2	North Lost Hills	Tulare & Etchegoin	Primary/ Steam flood	892
3	South Lost Hills	Monterey Shale	Primary	1,359
4	North Midway Sunset	Tulare & Potter	Steam flood	2,786
5	South Midway Sunset	Antelope	Steam flood	2,048
	TOTAL CALIFORNIA NET PRODUCTION(1)			7,597 Boe/d

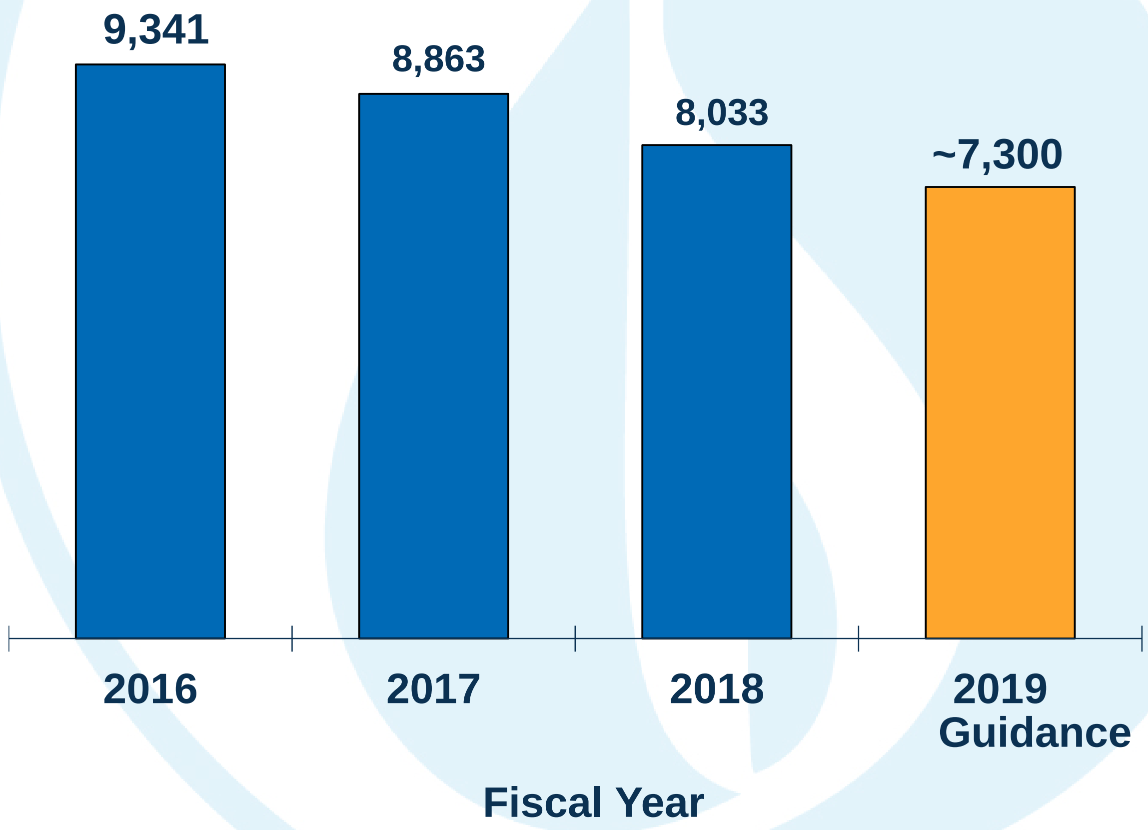
(1) California net production for FY 2018 excludes production from Sespe field, which was divested on May 1, 2018.

California Capital Expenditures vs. Production

West Division Annual Capital Expenditures ($ MM)(1)

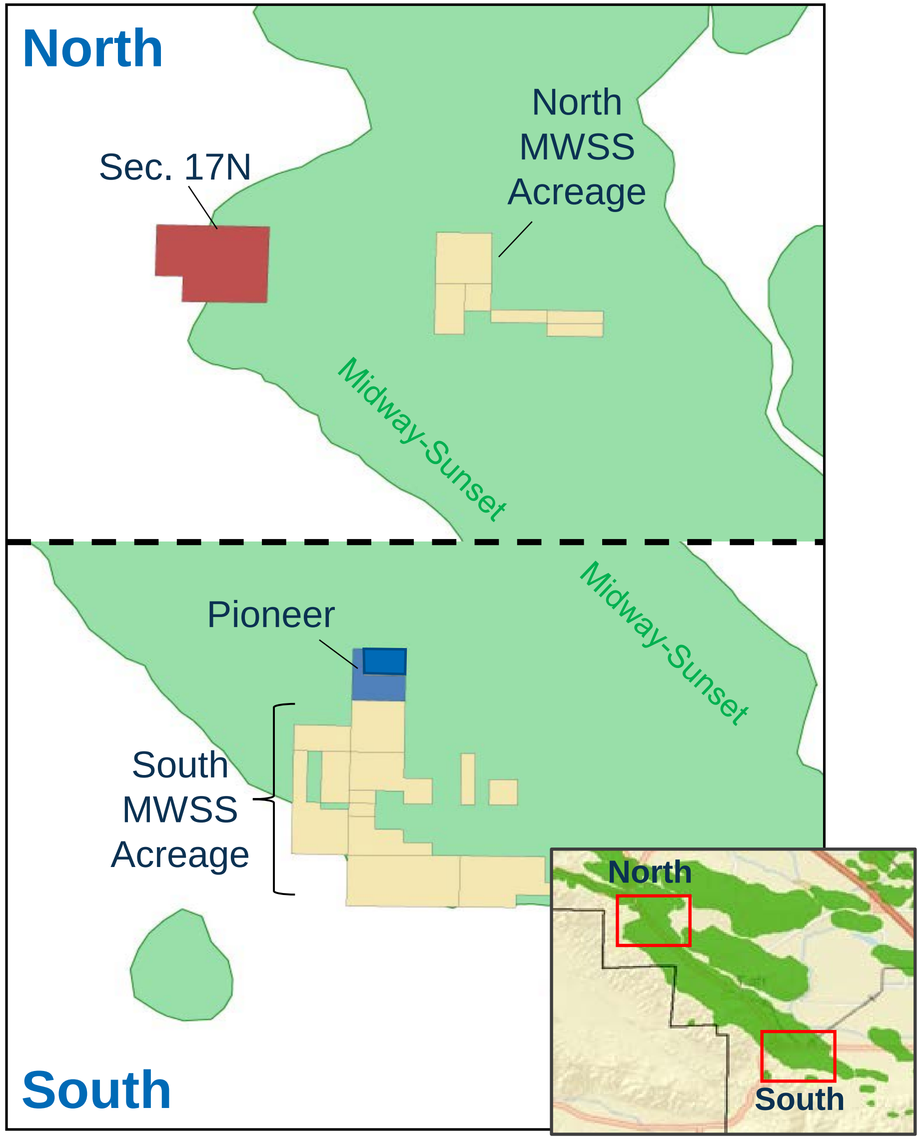


West Division Average Net Daily Production (Boe)



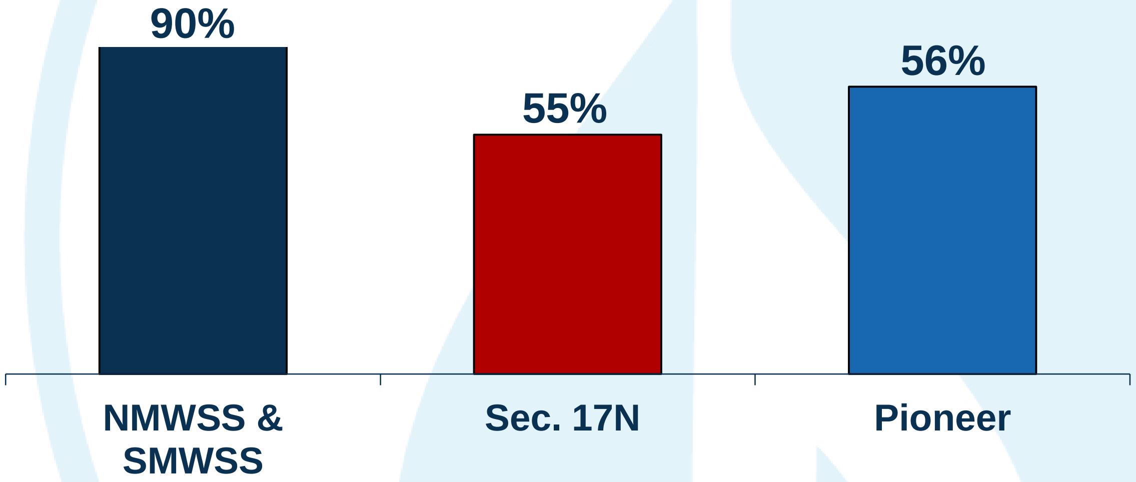
(1) Seneca West Division capital expenditures includes Seneca corporate and eliminations.

Future Development Focused on Midway Sunset



Midway Sunset Economics

MWSS Project IRRs at $70 /Bbl(1)



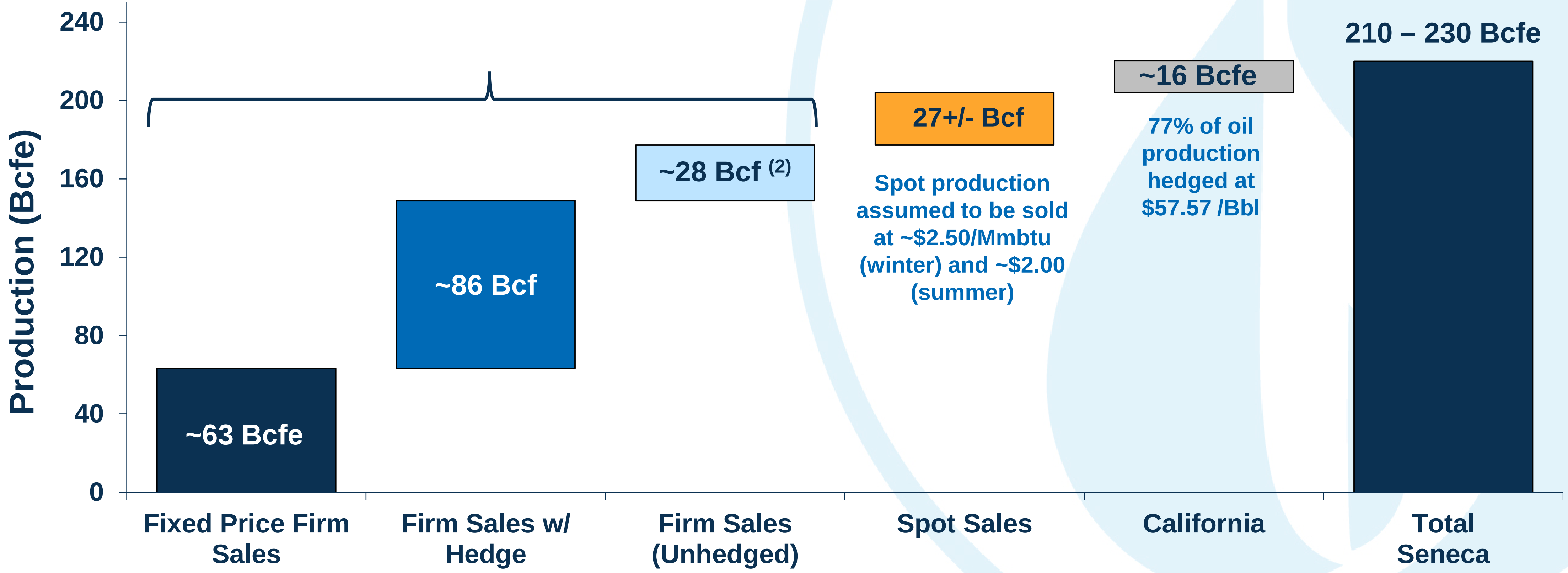
- ✓ Modest near-term capital program focused on locations that earn attractive returns in current oil price environment
- ✓ A&D will focus on low cost, bolt-on opportunities
- ✓ Sec. 17 and Pioneer farm-ins to provide future growth

(1) Reflects pre-tax IRRs at a $70/Bbl WTI.

Fiscal 2019 Production and Price Certainty

177 Bcf of Appalachian Production Protected by Firm Sales

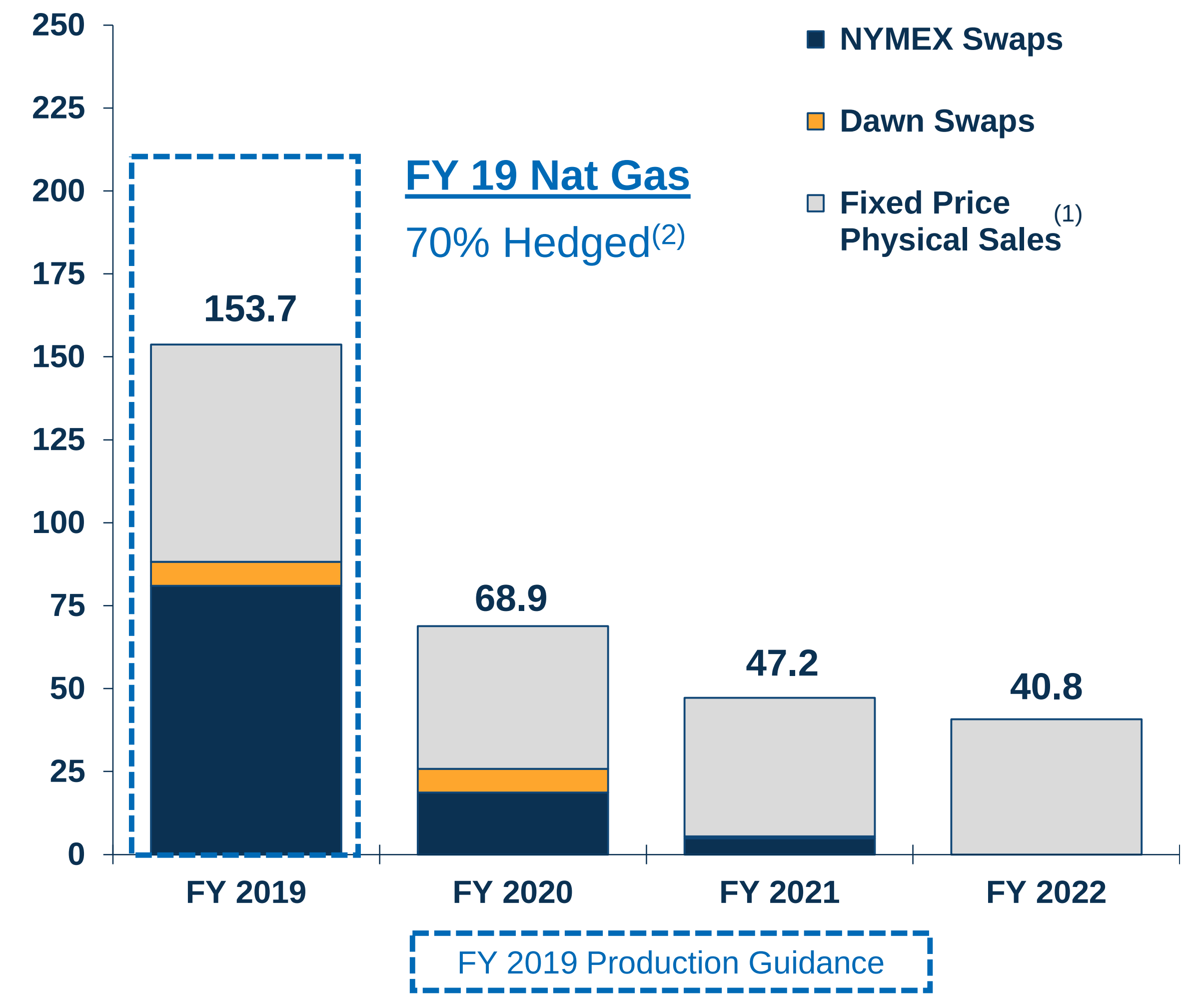
- 149 Bcf locked-in realizing net ~$2.43/Mcf (1)
- 28 Bcf of additional basis protection



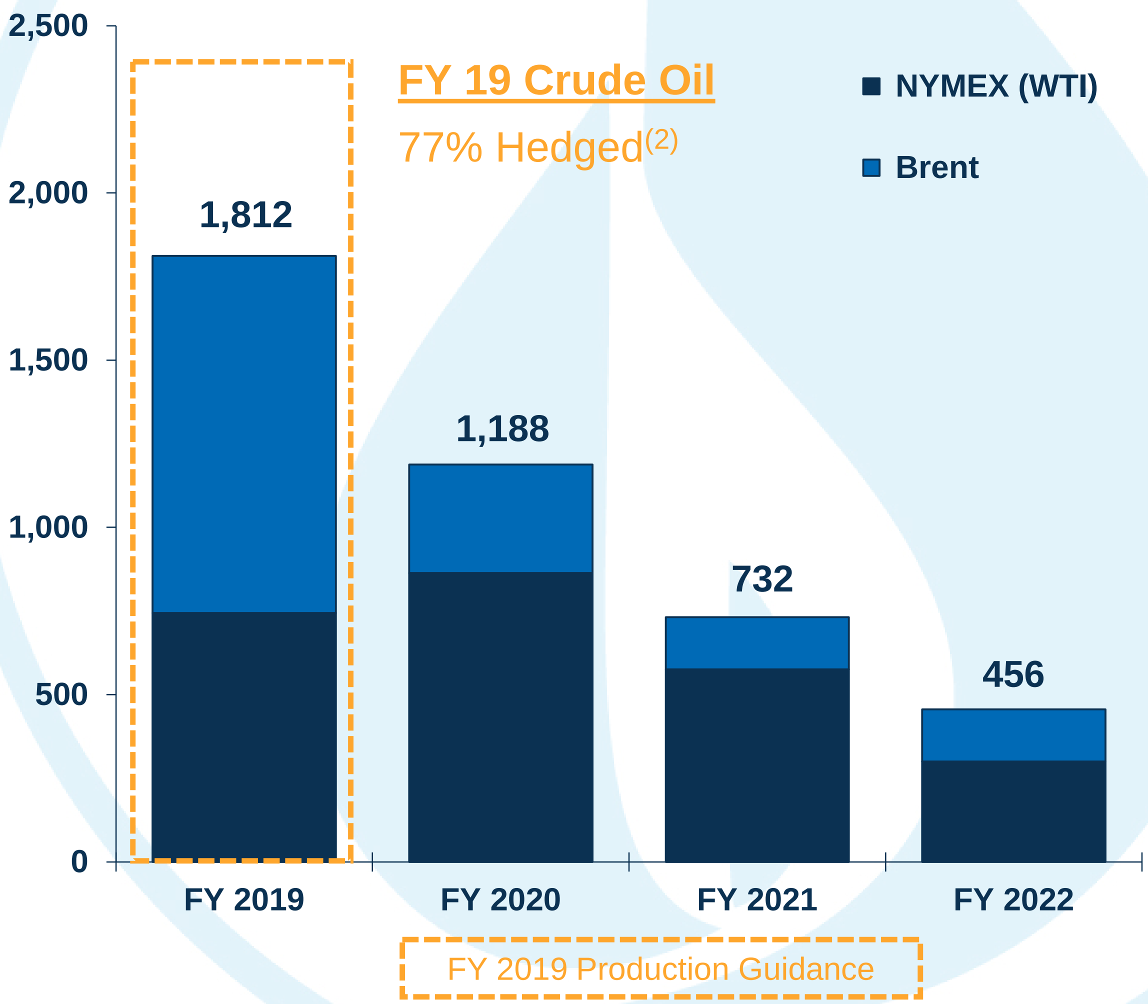
(1) Average realized price reflects uplift from financial hedges less fixed differentials under firm sales contracts and any firm transportation costs.
(2) Indicates firm sales contracts with fixed index differentials but not backed by a matching financial hedge.

Strong Hedge Book

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



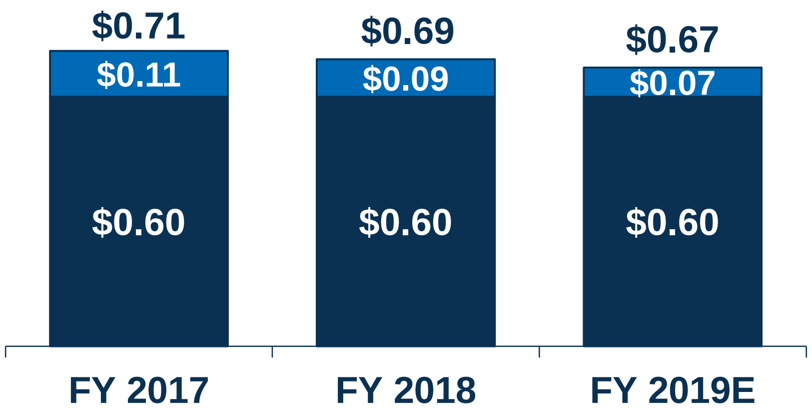
Crude Oil Swap Contracts *(Thousands Bbls)*



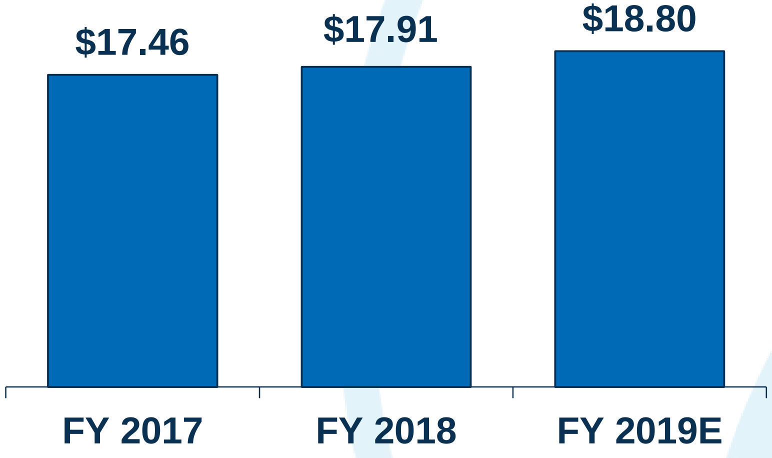
(1) Fixed price physical sales exclude joint development partner's share of fixed price contract WDA volumes as specified under the joint development agreement.
(2) Reflects percentage of projected production for FY19 hedged at the midpoint of the production guidance range.

Seneca Operating Costs

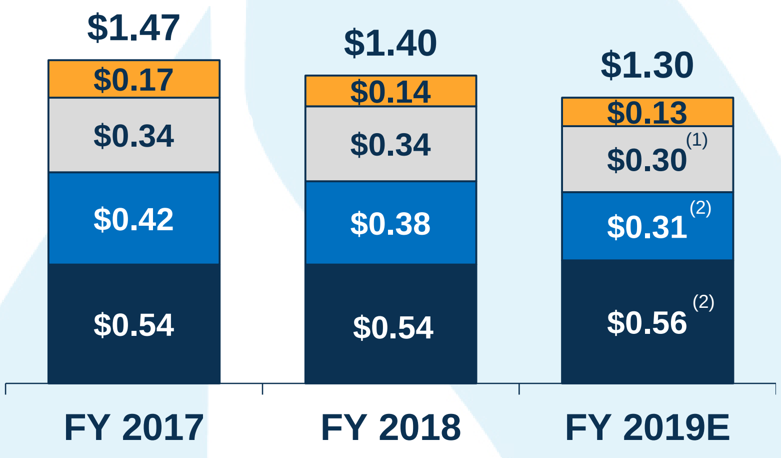
Appalachia LOE & Gathering
$/Mcfe



California LOE
$/Boe

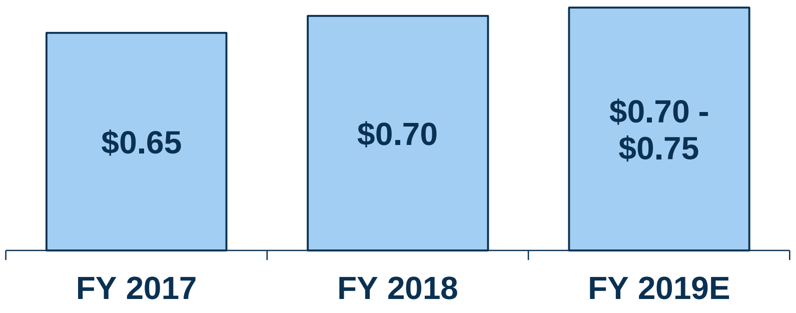


Total Seneca Cash OpEx
$/Mcfe



■ Gathering & Transport ■ LOE (non-Gathering) ■ G&A ■ Taxes & Other

Seneca DD&A Rate
$/Mcfe



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

(1) G&A estimate represents the midpoint of the G&A guidance range of $0.25 to $0.35 for fiscal 2019.
(2) The total of the two LOE components represents the midpoint of the LOE guidance range of $0.85 to $0.90 for fiscal 2019.

national fuel

Seneca's Continuing Commitment to the Environment

Water and Fluids Management

Seneca Resources Water Operations

Fiscal 2018

100%

Produced Water Recycled in Appalachia

70%
Recycled Water

Used in New Shale Well Completions

Air Quality and Emissions

Seneca Resources Remains Focused on Minimizing GHG Emissions

- ✓ The Environmental Partnership
- ✓ EPA Natural Gas Star Program
- ✓ Green Completions (all fiscal 2018 wells)
- ✓ Ultrasonic Leak Detection Technology
- ✓ Emissions Controls
- ✓ Rig and Vehicle Fuel Conversion
- ✓ Integrating Renewable Energy into Operations

Pipeline and Storage Overview

National Fuel Gas Supply Corporation ~ Empire Pipeline, Inc.

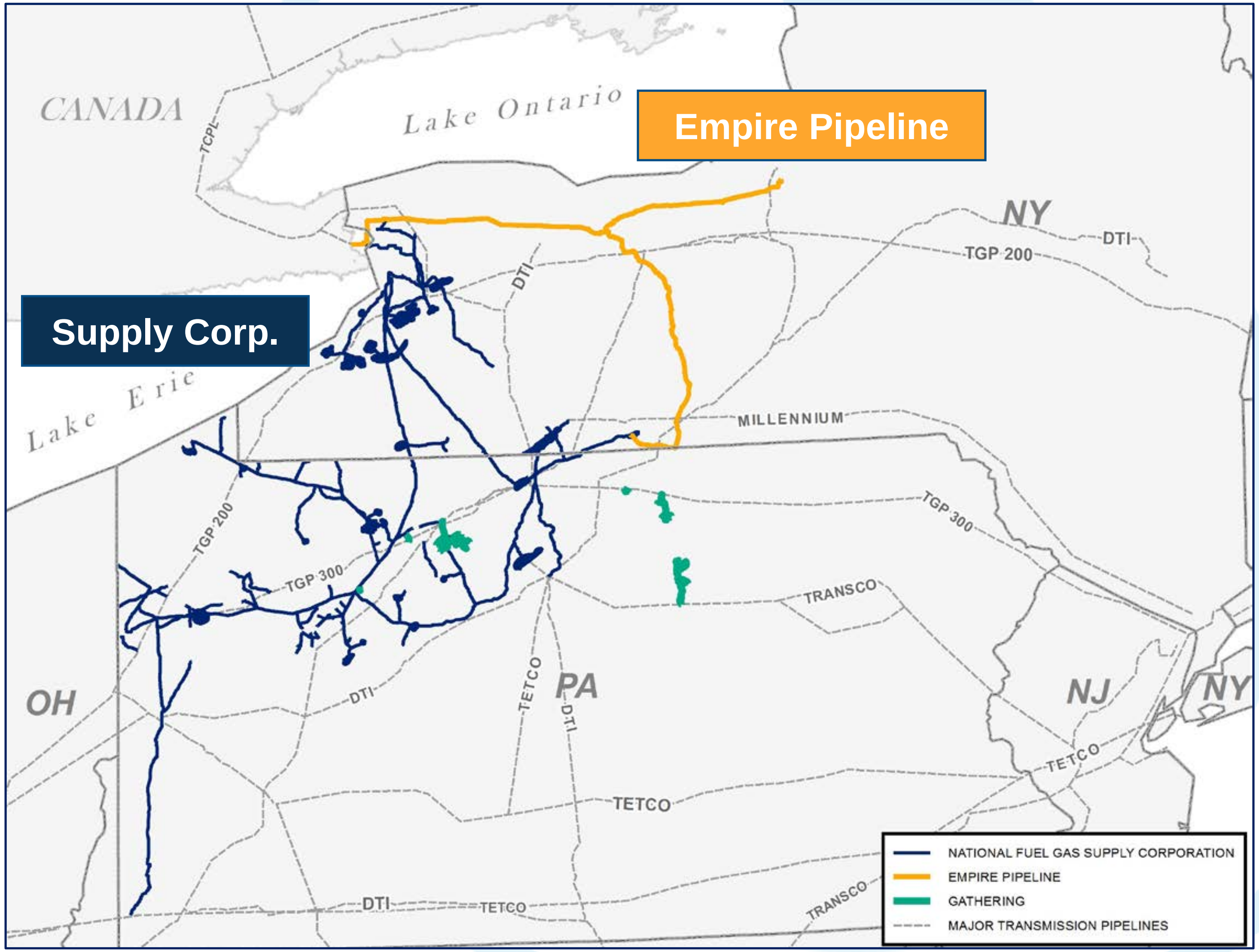
Pipeline & Storage Segment Overview

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 4 Rate Proceeding commenced 6/29/18
  - New transportation rates expected to go into effect on 1/1/19 (subject to refund)



(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 2017 FERC Form-2 reports, respectively.

FM100 Project - Consolidated Benefit for NFG

National Fuel

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

Supply Corp.

- ✓ **Lease to Transco of new capacity:** 330,000 Dth/day
- ✓ **Estimated annual lease revenues**: ~$35 million
- ✓ **Target In-Service:** late calendar year 2021

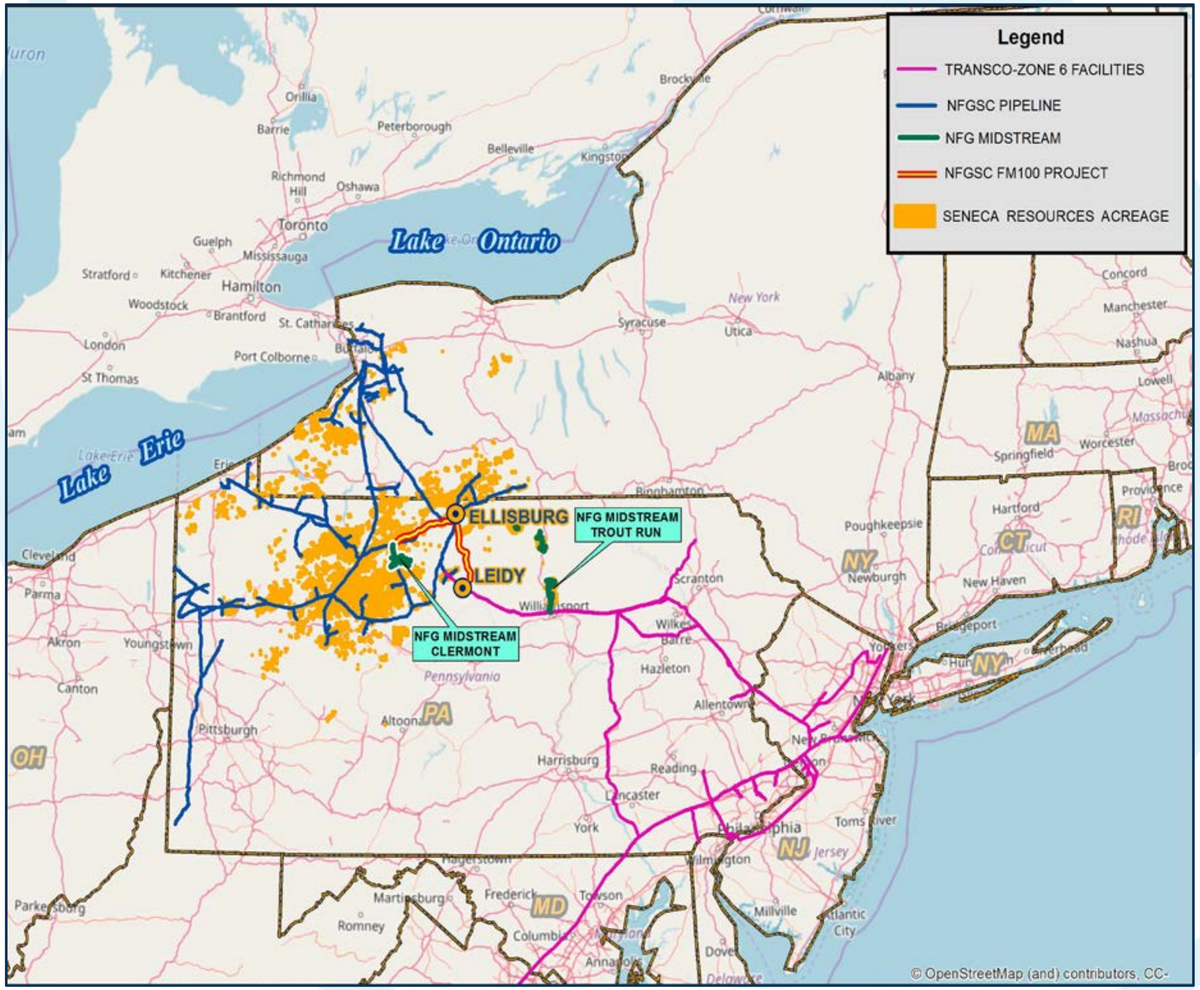
Seneca

- ✓ **New Transco capacity (Leidy South):** 330,000 Dth/day
- ✓ **Rate[1] :** expected to be competitive with other expansion project rates in Seneca's current transportation portfolio
- ✓ **Delivery Point(s):** Transco Zone 6 interconnections

Gathering

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

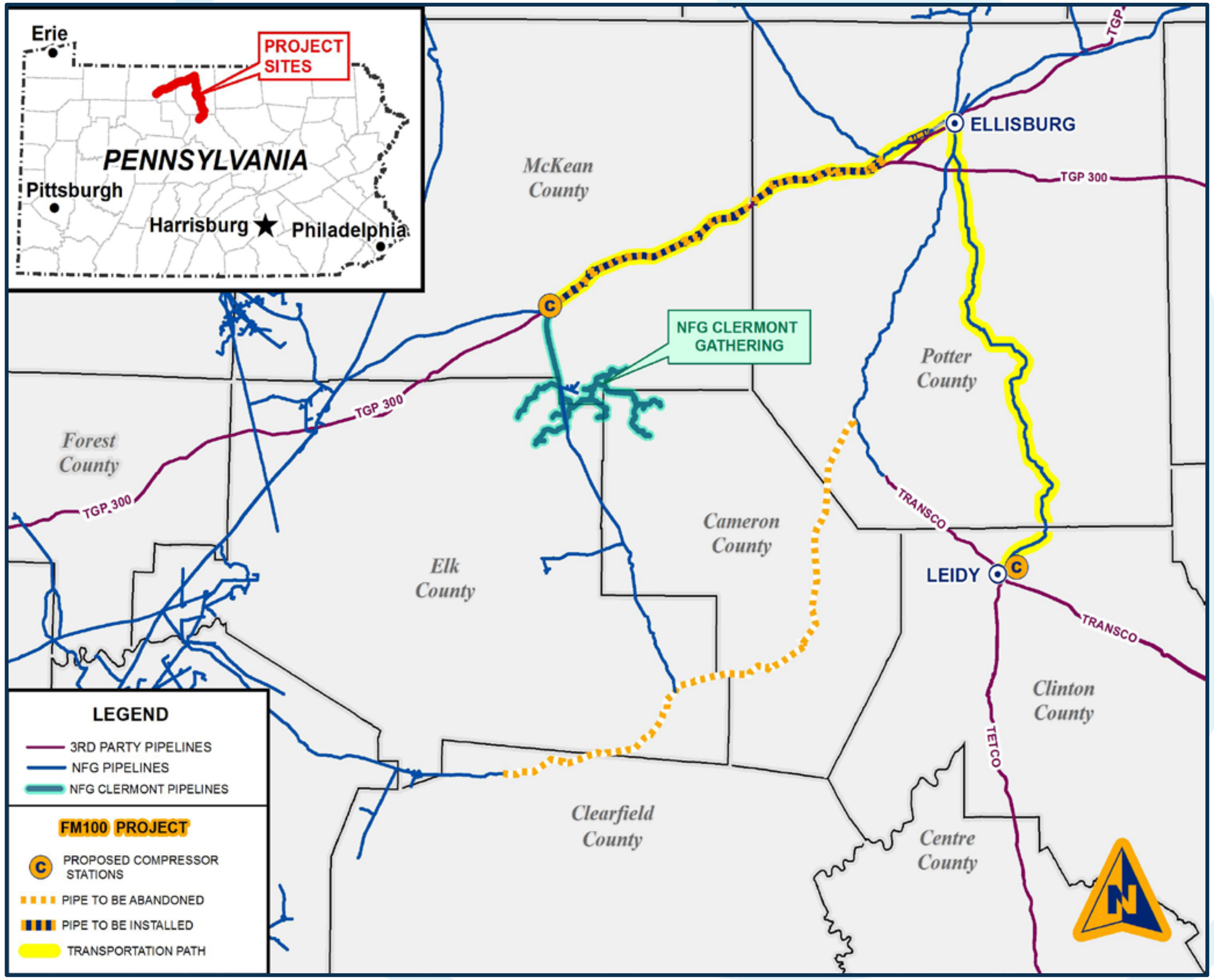
330,000 Dth/d of new transportation capacity from WDA and EDA acreage positions to premium markets



(1) Includes lease of new capacity from Supply Corp. to Transco.

FM100 Project – Significant Investment by Supply Corp.

- **Estimated Capital Cost:** $280 million(1)
- **Facilities (all in Pennsylvania) include:**
  - Approximately 30 miles of new pipeline
  - 2 new compressor Stations (totaling approximately 37,000 HP)
  - New interconnection station and modification of existing interconnection station
  - Abandonment of approximately 45 miles of existing pipeline and compressor station
- **Regulatory Process:**
  - Pre-filing application submitted to FERC in 2017 for original modernization project
  - FERC 7(b) / 7(c) filing expected summer 2019



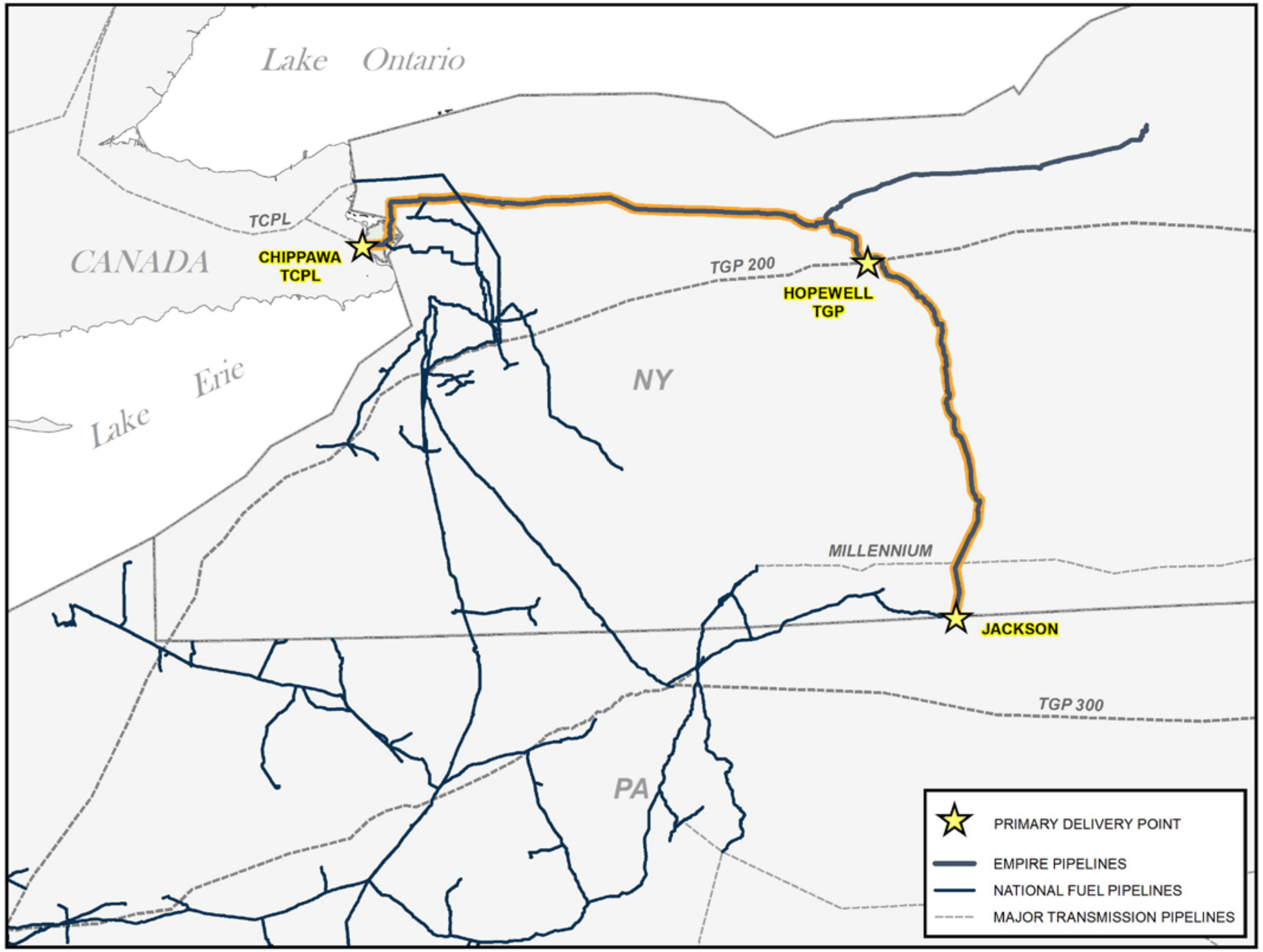
(1) Includes expansion and modernization portions of the project.

National Fuel

Empire North Project

Fully Subscribed Project will Provide 205,000 Dth/day of Incremental Firm Transportation

- **Target In-Service:** Second half of fiscal 2020
- **Est. Capital Cost:** $145 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
    - FERC Environmental Assessment issued 10/30/18



National Fuel Remains Committed to Northern Access Project

Target In-Service: first half of fiscal 2022

Total Cost: ~$500MM (~$76MM spent to date)

Estimated Annual Revenues: ~$84 million

Delivery Points:

✓ 350,000 Dth/d to Chippawa (TCPL interconnect)

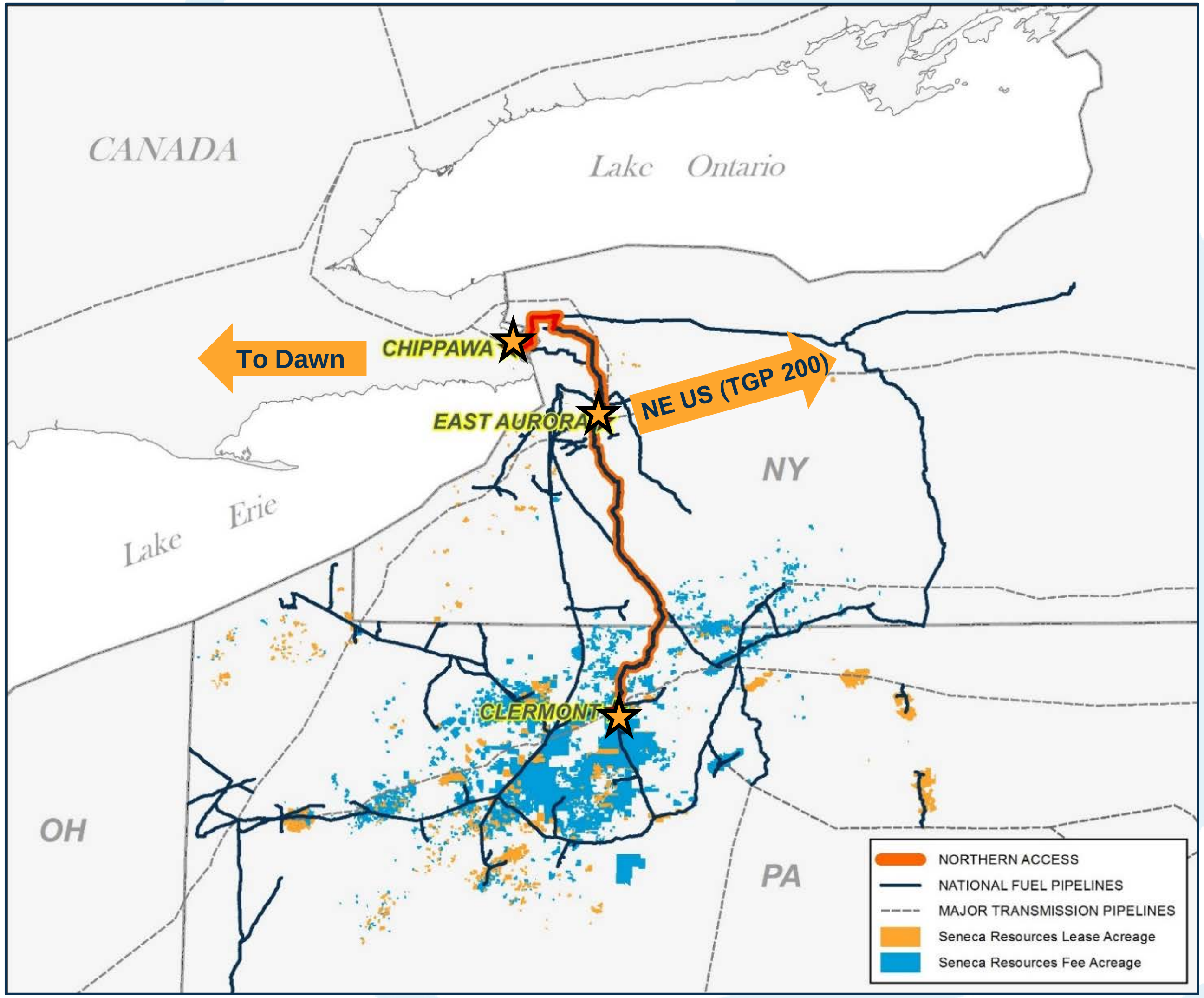
✓ 140,000 Dth/d to Hopewell (TGP 200 line)

Regulatory Status:

✓ February 3, 2017 – FERC 7(c) certificate issued

✓ August 6, 2018 – FERC issued Order finding that NY DEC waived water quality certification

✓ Supply and Empire currently working to finalize remaining federal authorizations



Continued Expansion of the NFG Supply System

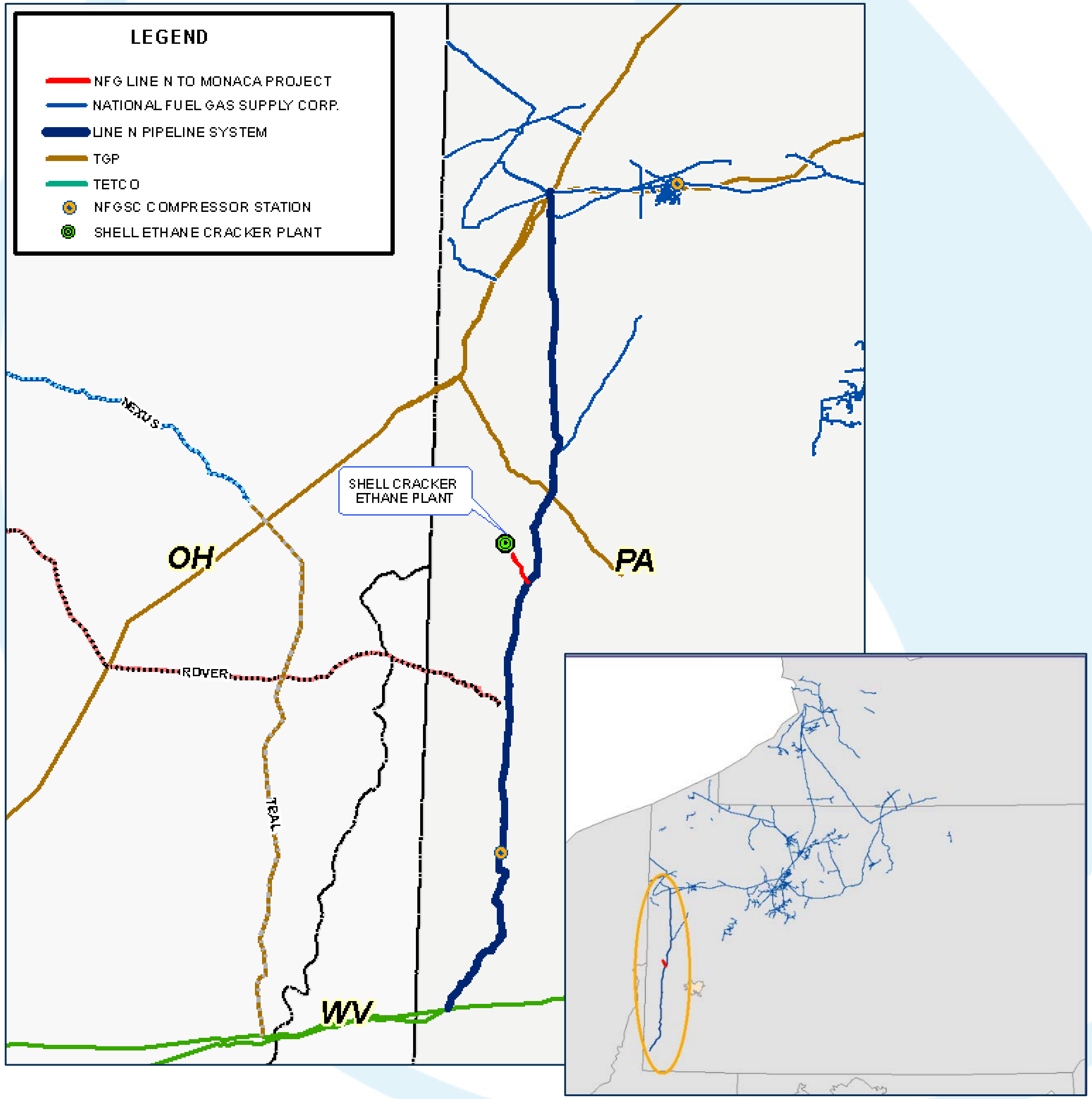
Line N Expansion Opportunities

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
- **Estimated Capital Cost:** $23 million
- **Contracted Capacity:** 133,000 Dth/day

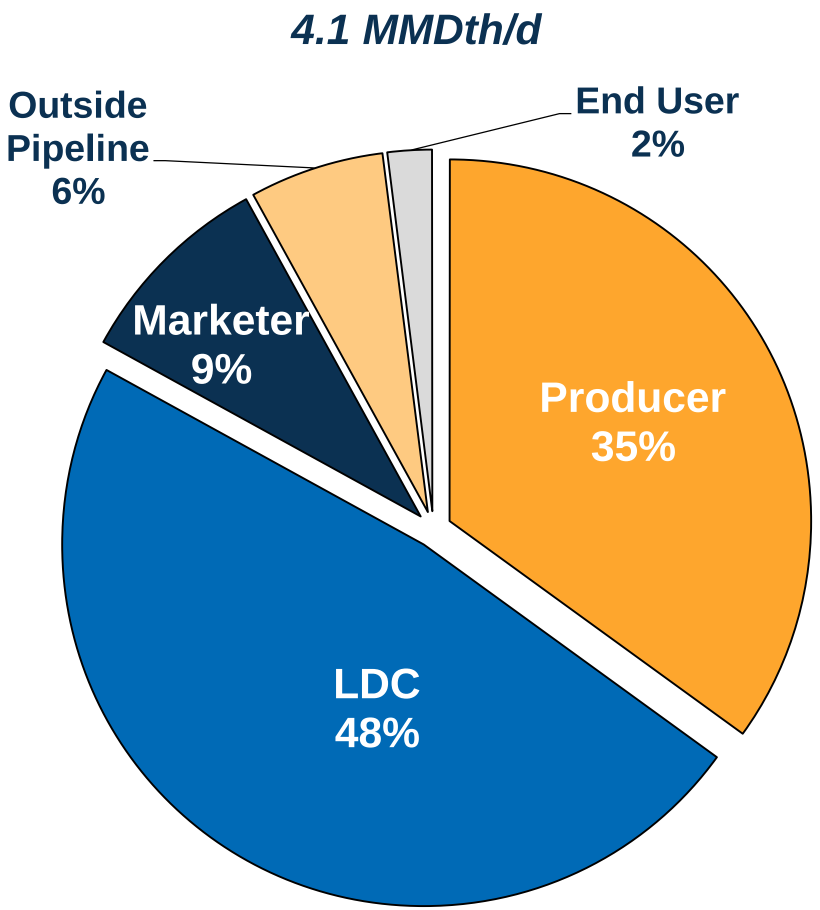
Additional Line N Expansion Opportunity (Supply OS #221)

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

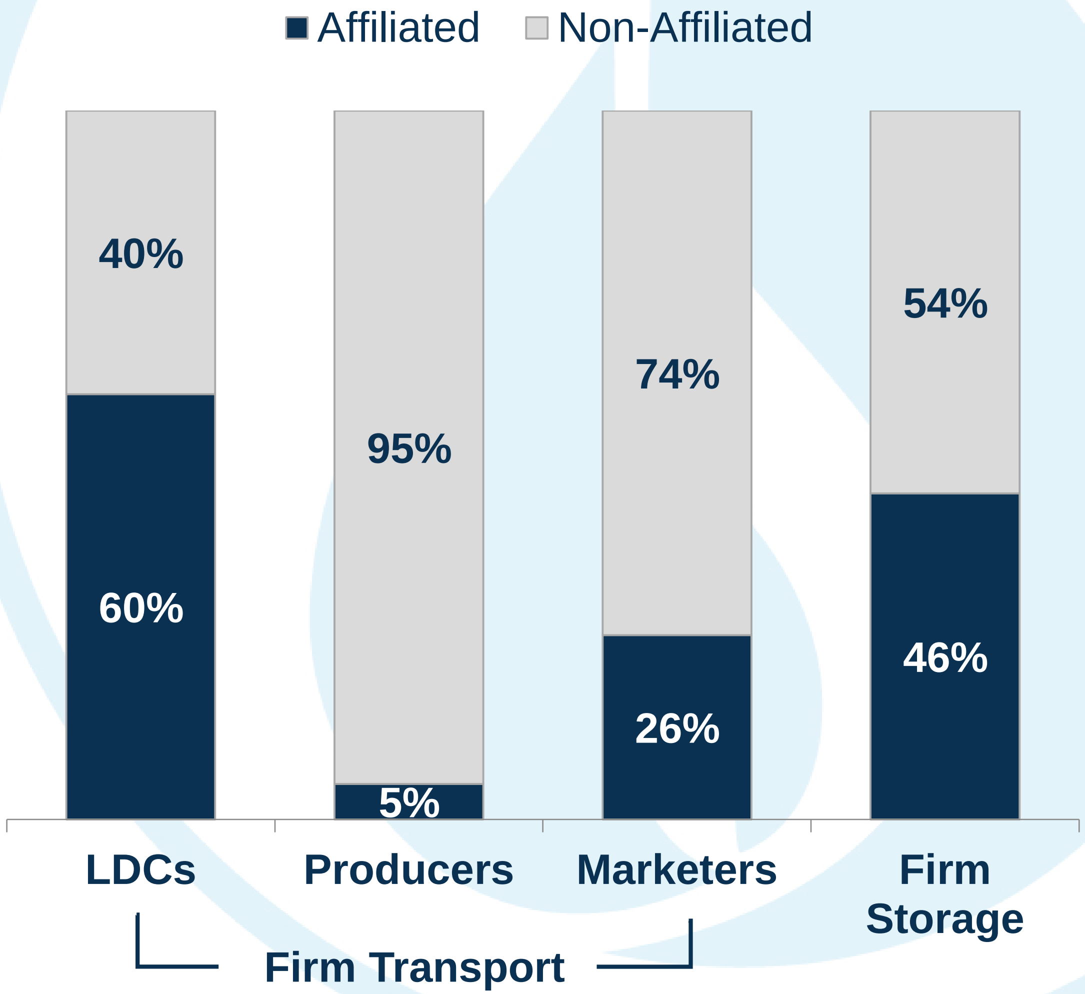


Pipeline & Storage Customer Mix

Customer Transportation by Shipper Type[1]



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]: 535,800

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)
- System Modernization Tracker

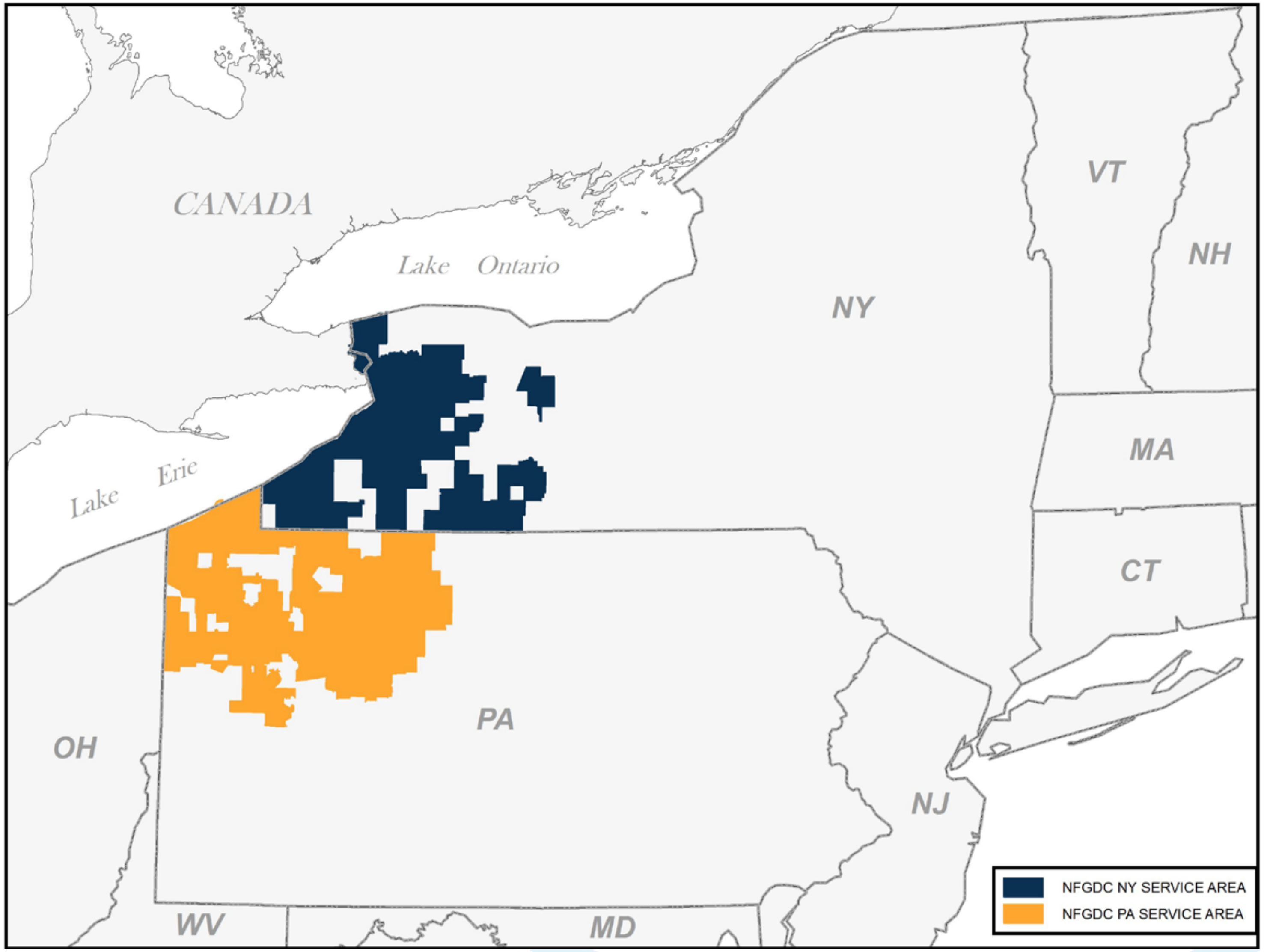
Pennsylvania

Total Customers[1]: 214,400

ROE: Black Box Settlement (2007)

Rate Mechanisms:

- Low Income Rates
- Merchant Function Charge



(1) As of September 30, 2018.

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.

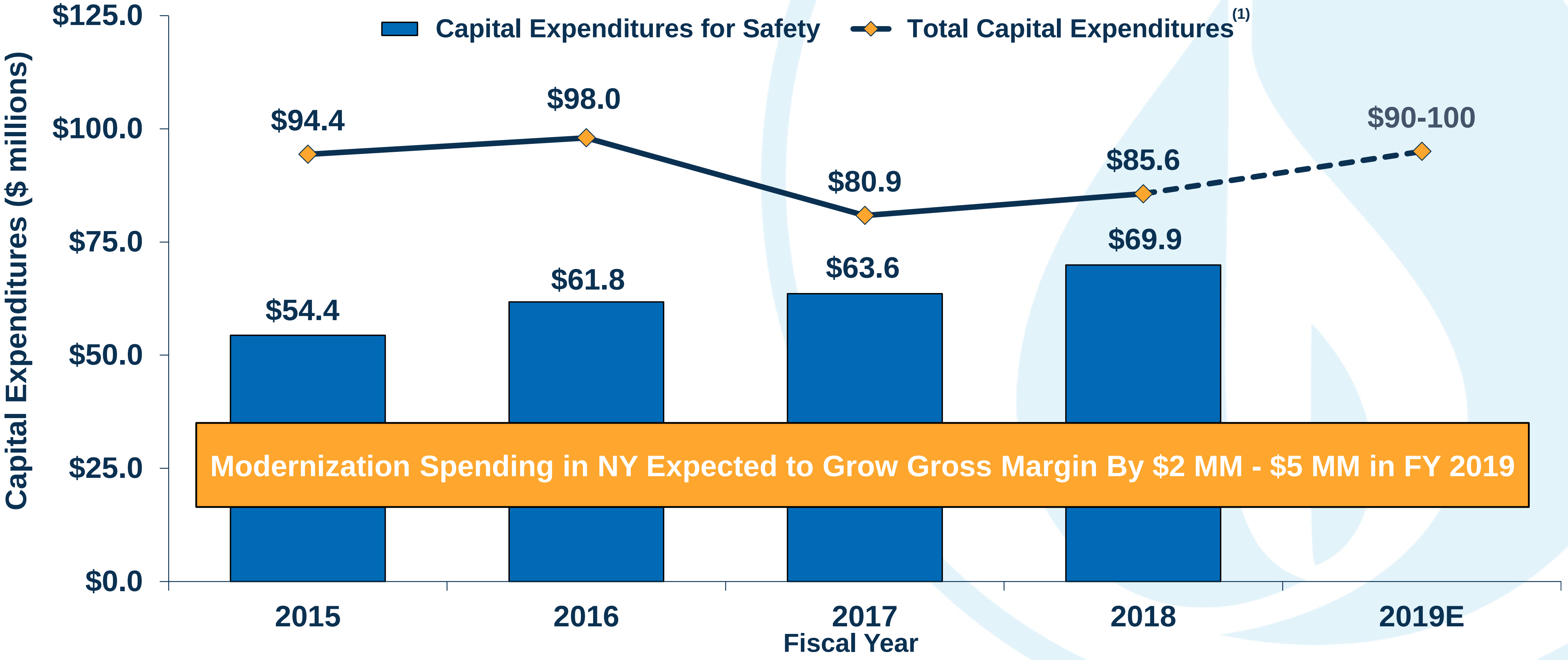
Rate Order Summary:

- **Revenue Requirement:** $5.9 million
- **Rate Base:** $704 million
- **Allowed Return on Equity (ROE):** 8.7%
- **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
  - System modernization tracker for Leak Prone Pipe (LPP)
  - Earnings sharing starting 4/1/18 (50/50 sharing starts at earnings in excess of 9.2%)
  - Article 78 appeal filed on 7/28/17, with oral argument scheduled for January 2019

National Fuel

Utility Continues its Significant Investments in Safety

System modernization tracker in NY allows recovery of pipeline replacement costs, which is expected to drive modest gross margin and rate base growth

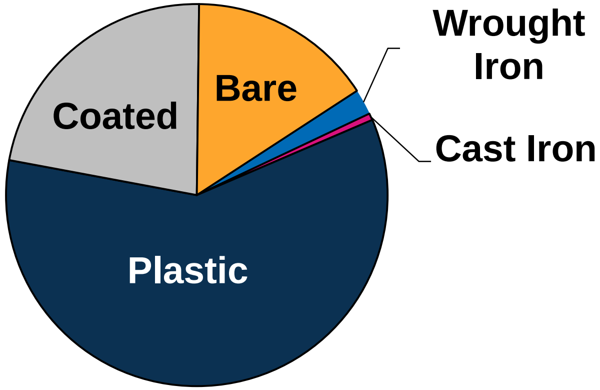


(1) A reconciliation to Capital Expenditures as presented on the Consolidated Statement of Cash Flows is included at the end of this presentation.

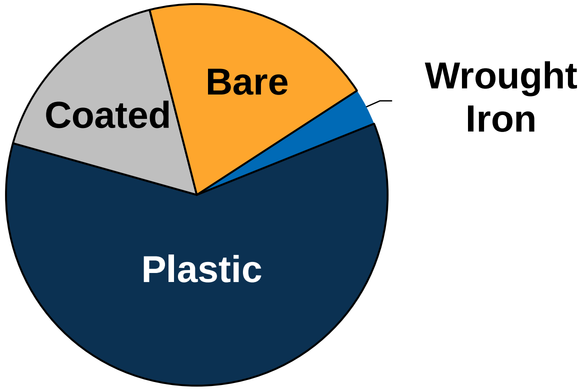
Accelerating Pipeline Replacement & Modernization

Utility Mains by Material

NY
9,723 miles

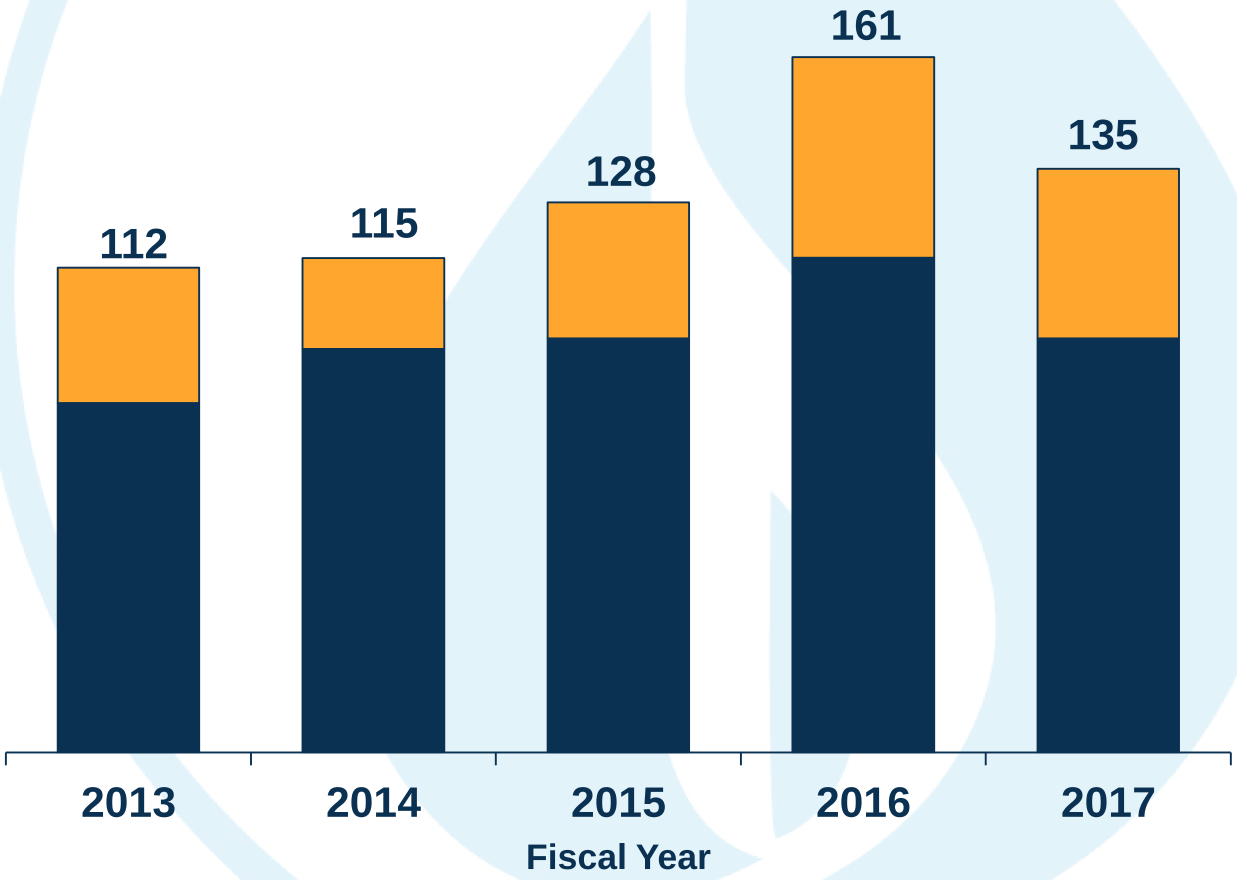


PA*
4,832 miles



No Cast Iron Mains in Pa.

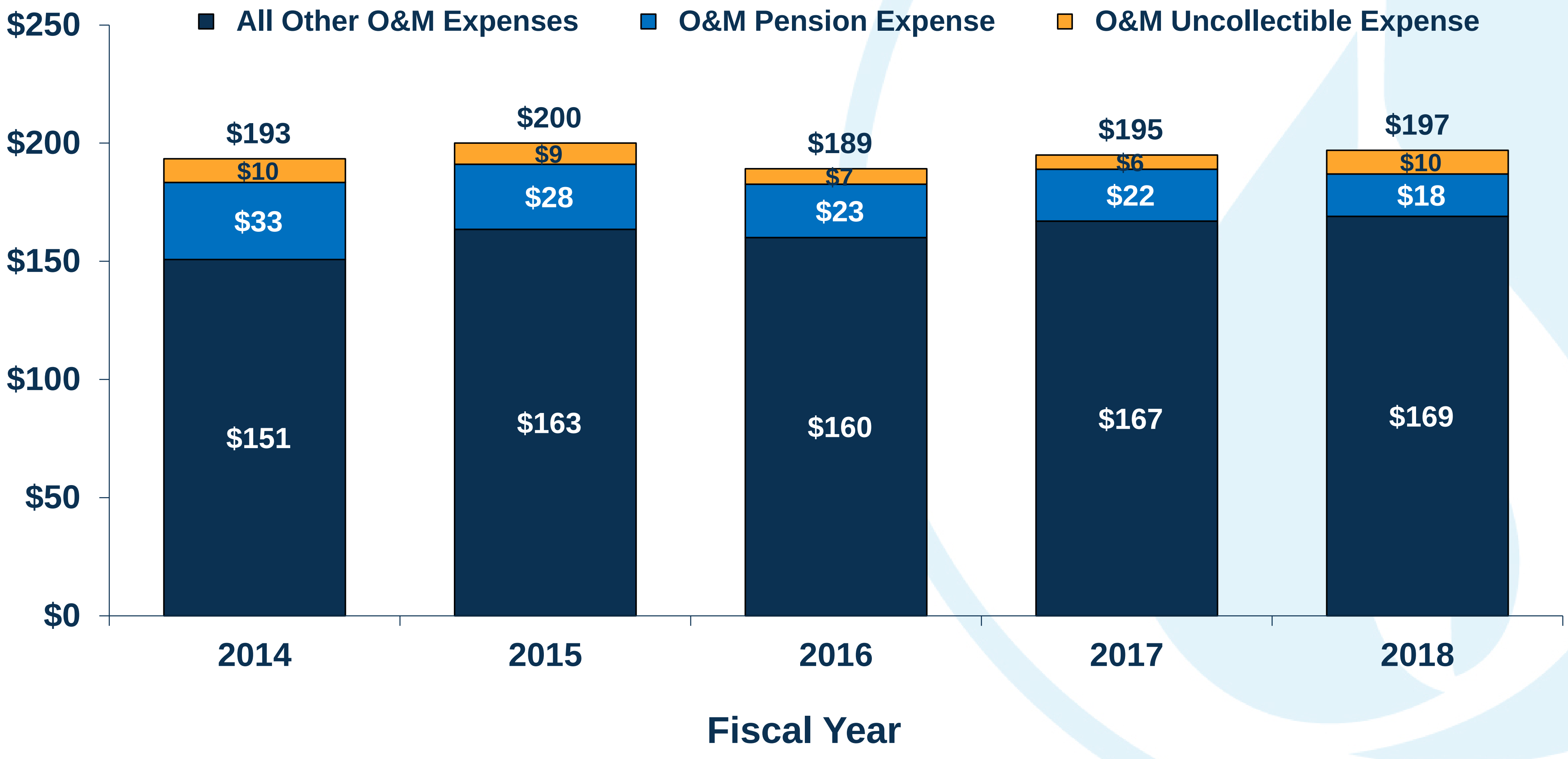
Miles of Utility Main Pipeline Replaced(1)



(1) As reported to the Department of Transportation on calendar year basis.

A Proven History of Controlling Costs

O&M Expense ($ millions)

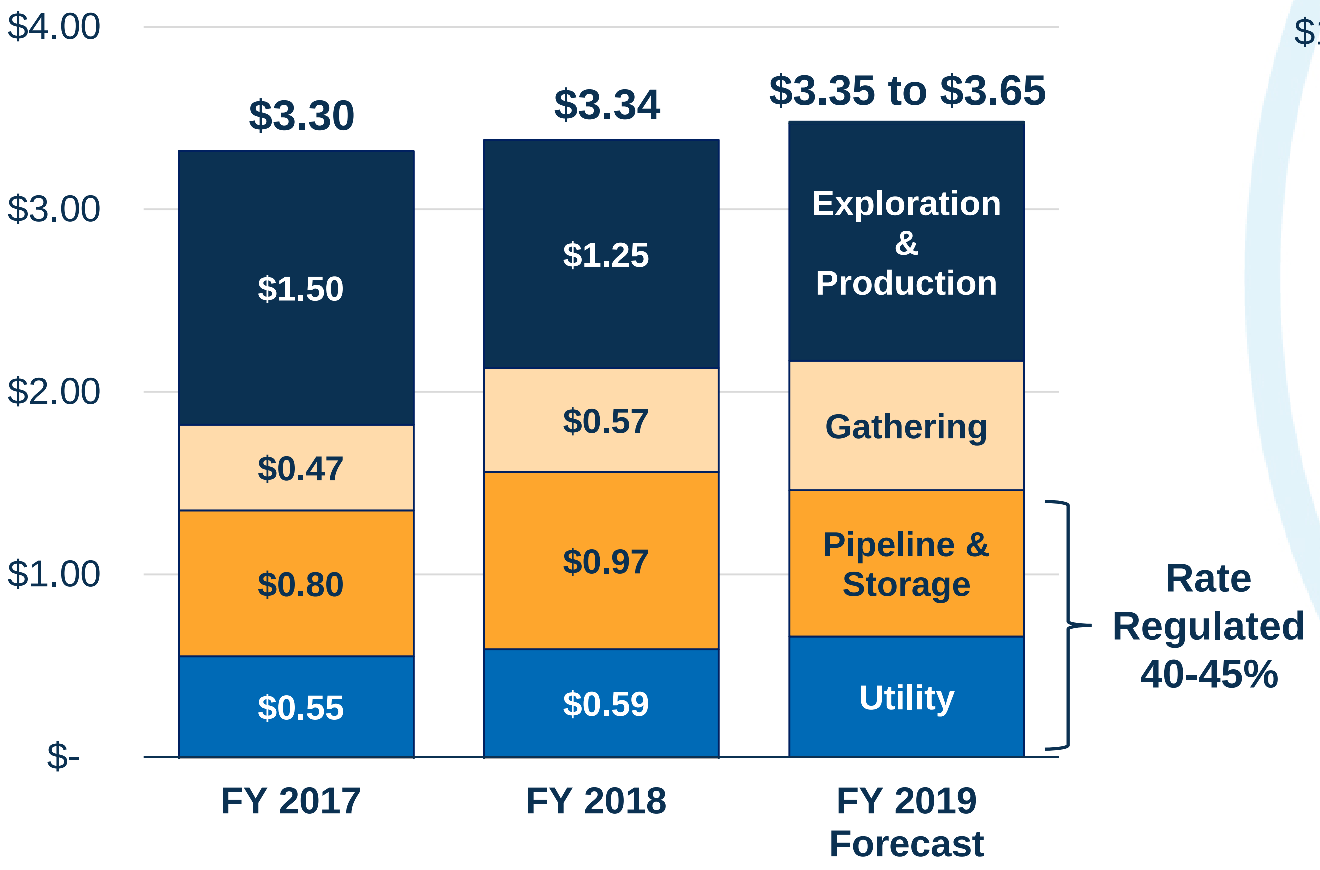


Consolidated Financial Overview

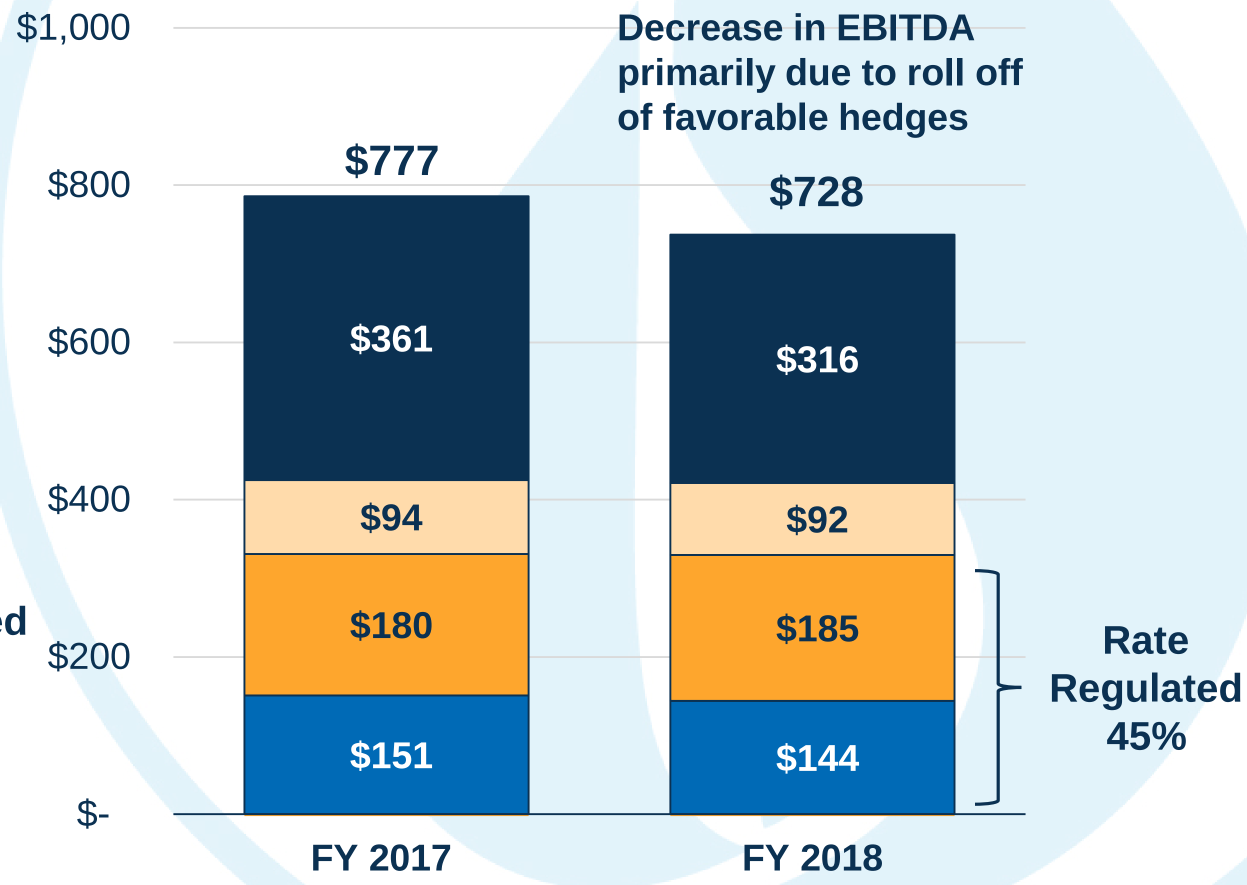
Upstream | Midstream | Downstream

Diversified, Balanced Earnings and Cash Flows

Adjusted Operating Results ($ per share)(1)



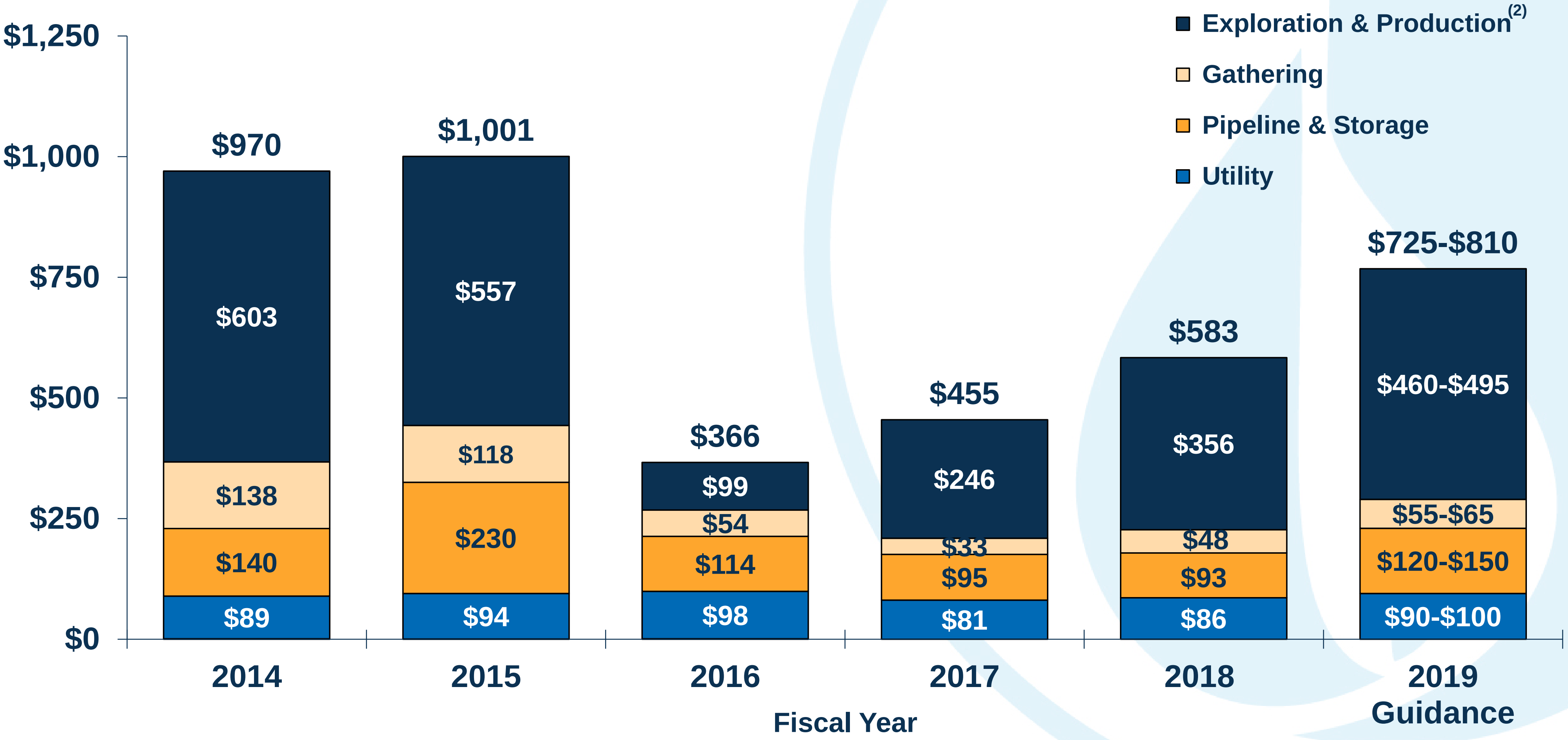
Adjusted EBITDA ($ millions)(2)



(1) A reconciliation of Adjusted Operating Results to Earnings per Share, by segment, 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 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

Disciplined, Flexible Capital Allocation

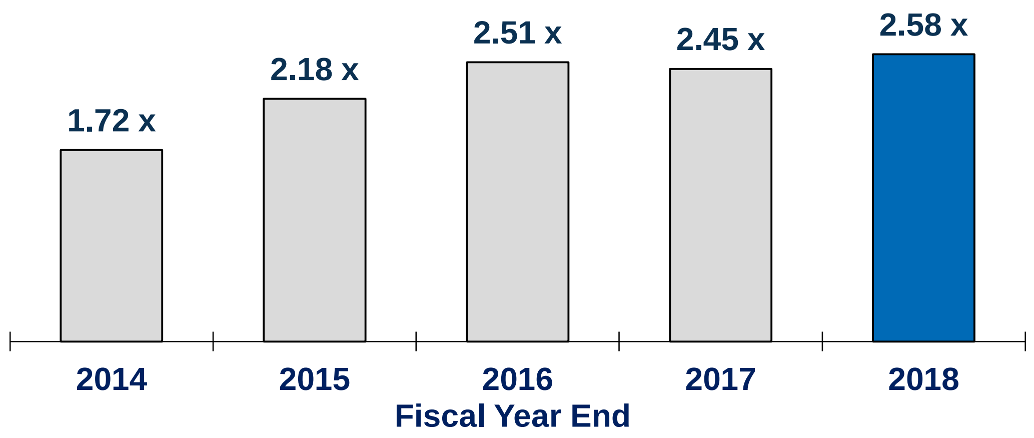
Capital Expenditures by Segment ($ millions)(1)



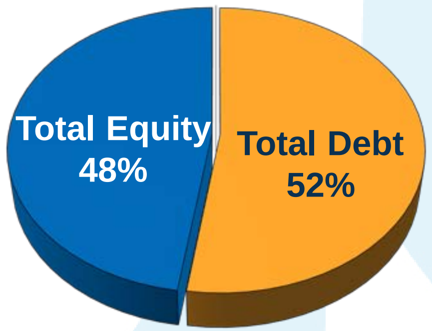
(1) Total Capital Expenditures include Energy Marketing, Corporate and All Other. A reconciliation to Capital Expenditures as presented on the Consolidated Statement of Cash Flows is included at the end of this presentation.
(2) FY16, FY17, and FY18 reflects the netting of $157 million, $7 million, and $17 million, respectively, of up-front proceeds received from joint development partner for working interest in joint development wells, and $21M in intercompany asset transfers in FY18.

Maintaining Strong Balance Sheet & Liquidity

Net Debt / Adjusted EBITDA[1]

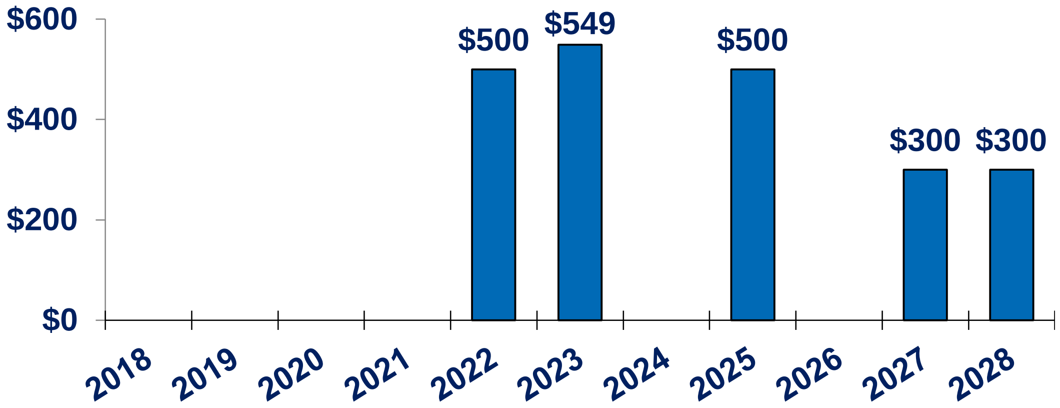


Capitalization



$4.1 Billion Total Capitalization as of September 30, 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 9/30/18	230 MM
Total Liquidity at 9/30/18	**$ 980 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.

Appendix

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 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; financial and economic conditions, including the availability of credit, and occurrences affecting the Company's ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company's credit ratings and changes in interest rates and other capital market conditions; changes in the price of natural gas or oil; impairments under the SEC's full cost ceiling test for natural gas and oil reserves; 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, March 31, 2018, and June 30, 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.

Hedge Positions and Prices

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

	Fiscal 2019		Fiscal 2020		Fiscal 2021		Fiscal 2022	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
NYMEX Swaps	80,980	$2.94	18,640	$3.04	4,840	$3.01	-	-
Dawn Swaps	7,200	$3.00	7,200	$3.00	600	$3.00	-	-
Fixed Price Physical(1)	65,483	$2.68	43,025	$2.31	41,805	$2.22	40,783	$2.23
Total	**153,663**	**$2.83**	**68,865**	**$2.58**	**47,245**	**$2.31**	**40,783**	**$2.23**

Crude Oil Volumes & Prices in Bbl

	Fiscal 2019		Fiscal 2020		Fiscal 2021		Fiscal 2022	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
Brent Swaps	744,000	$63.52	864,000	$63.51	576,000	$64.68	300,000	$60.07
NYMEX Swaps	1,068,000	$53.42	324,000	$50.52	156,000	$51.00	156,000	$51.00
Total	**1,812,000**	**$57.57**	**1,188,000**	**$59.96**	**732,000**	**$61.61**	**456,000**	**$56.97**

(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 Marcellus and Utica Inventory Economic at ~$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] $2.50 Realized	$2.25 Realized	$2.00 Realized	Realized Price[1] Required for 15% IRR	Anticipated Delivery Markets
EDA	**Tract 100 & Gamble** *Lycoming Co.*	Marcellus	49	4,900	2.5	$1,022	80%	62%	46%	$1.50	**Transco Leidy & Atlantic Sunrise** Southeast US (NYMEX+)
EDA	**DCNR 007** *Tioga Co.*	Utica	43	8,300	2.0	$1,011	53%	39%	25%	$1.80	TGP 300
WDA	Clermont Rich Valley	Utica	120+	9,000	1.7	$892	29%	23%	16%	$1.97	**TGP 300, Niagara Expansion** Canada (Dawn), & **FM100/Leidy South** (Transco Zone 6)
WDA	Core Areas	Marcellus	600+	8,500	1.0 to 1.1	$637	27%	20%	14%	$2.04	

(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

		Production Source	Volume (Dth/d)	Delivery Market	Demand Charges ($/Dth)	Gas Marketing Strategy
Currently In-Service	**Northeast Supply Diversification** *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
			12,000	TETCO (SE Pa.)	NFG pipelines = $0.12	
Currently In-Service	**Atlantic Sunrise** *WMB - Transco*	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 Leidy South / NFG FM100** *WMB – Transco; NFG - Supply* *In-service: late 2021*	WDA – Clermont/ Rich Valley and EDA - Lycoming County	330,000	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* *In-Service: late 2021/ early 2022*	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
			140,000	TGP 200 (NY)	NFG pipelines = $0.38	

(1) Seneca's Leidy South transportation rate is inclusive of Transco's lease payments (~$35 million annually) to Supply Corp. for new capacity created by FM100 Project.

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 twelve months September 30, 2018 by $103.5 million, or $1.20 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 fiscal 2019, 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 EBITDA

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018
Total Adjusted EBITDA					
Exploration & Production Adjusted EBITDA	$ 539,472	$ 422,289	$ 363,830	$ 360,979	$ 315,753
Pipeline & Storage Adjusted EBITDA	186,022	188,042	199,446	180,328	185,393
Gathering Adjusted EBITDA	64,060	68,881	78,685	94,380	91,609
Utility Adjusted EBITDA	164,643	164,037	148,683	151,078	144,155
Energy Marketing Adjusted EBITDA	10,335	12,237	6,655	2,080	536
Corporate & All Other Adjusted EBITDA	(11,078)	(11,900)	(8,238)	(11,805)	(9,399)
Total Adjusted EBITDA	**$ 953,454**	**$ 843,586**	**$ 789,061**	**$ 777,040**	**$ 728,047**
Total Adjusted EBITDA	**$ 953,454**	**$ 843,586**	**$ 789,061**	**$ 777,040**	**$ 728,047**
Minus: Interest Expense	(94,277)	(99,471)	(121,044)	(119,837)	(114,522)
Plus: Interest and Other Income	13,631	11,961	14,055	11,156	11,463
Minus: Income Tax Expense	(189,614)	319,136	232,549	(160,682)	7,494
Minus: Depreciation, Depletion & Amortization	(383,781)	(336,158)	(249,417)	(224,195)	(240,961)
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)	-	-
Rounding	-	-	-	-	-
Consolidated Net Income	**$ 299,413**	**$ (379,427)**	**$ (290,958)**	**$ 283,482**	**$ 391,521**
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	$ 2,149,000
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)	(229,606)
Total Net Debt (End of Period)	$ 1,697,714	$ 1,985,404	$ 1,969,028	$ 1,843,470	$ 1,919,394
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)	-	-	-	-	300,000
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)	(555,530)
Total Net Debt (Start of Period)	$ 1,584,142	$ 1,697,714	$ 1,985,404	$ 1,969,028	$ 1,843,470
Average Total Net Debt	**$ 1,640,928**	**$ 1,841,559**	**$ 1,977,216**	**$ 1,906,249**	**$ 1,881,432**
Average Total Net Debt to Total Adjusted EBITDA	**1.72 x**	**2.18 x**	**2.51 x**	**2.45 x**	**2.58 x**

Non-GAAP Reconciliations – Adjusted EBITDA, by Segment

Reconciliation of Adjusted EBITDA to Net Income, by Segment

($ Thousands)

	FY 2017	FY 2018
Exploration and Production Segment		
Reported GAAP Earnings	$ 129,326	$ 180,632
Depreciation, Depletion and Amortization	112,565	124,274
Interest and Other Income	(707)	(1,479)
Interest Expense	53,702	54,288
Income Taxes	66,093	(41,962)
Adjusted EBITDA	**$ 360,979**	**$ 315,753**
Pipeline and Storage Segment		
Reported GAAP Earnings	$ 68,446	$ 97,246
Depreciation, Depletion and Amortization	41,196	43,463
Interest and Other Income	(3,978)	(4,505)
Interest Expense	33,717	31,383
Income Taxes	40,947	17,806
Adjusted EBITDA	**$ 180,328**	**$ 185,393**
Gathering Segment		
Reported GAAP Earnings	$ 40,377	$ 83,519
Depreciation, Depletion and Amortization	16,162	17,313
Interest and Other Income	(995)	(1,106)
Interest Expense	9,142	9,560
Income Taxes	29,694	(17,677)
Adjusted EBITDA	**$ 94,380**	**$ 91,609**

($ Thousands)

	FY 2017	FY 2018
Utility Segment		
Reported GAAP Earnings	$ 46,935	$ 51,217
Depreciation, Depletion and Amortization	52,582	53,253
Interest and Other Income	(1,825)	(2,326)
Interest Expense	28,492	26,753
Income Taxes	24,894	15,258
Adjusted EBITDA	**$ 151,078**	**$ 144,155**
Energy Marketing Segment		
Reported GAAP Earnings	$ 1,509	$ 373
Depreciation, Depletion and Amortization	279	275
Interest and Other Income	(646)	(766)
Interest Expense	47	22
Income Taxes	891	632
Adjusted EBITDA	**$ 2,080**	**$ 536**
Corporate and All Other		
Reported GAAP Earnings	$ (3,111)	$ (21,466)
Depreciation, Depletion and Amortization	1,411	2,383
Interest and Other Income	(3,005)	(1,281)
Interest Expense	(5,263)	(7,484)
Income Taxes	(1,837)	18,449
Adjusted EBITDA	**$ (11,805)**	**$ (9,399)**

Non-GAAP Reconciliations – Adjusted Operating Results

(in thousands except per share amounts)	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Fiscal Year Ended September 30, 2018	Fiscal Year Ended September 30, 2017
Reported GAAP Earnings	$ 37,994	$ 45,577	$ 391,521	$ 283,482
Items impacting comparability				
Remeasurement of deferred income taxes under 2017 Tax Reform	3,516	—	(103,484)	—
Premium paid on early redemption of debt (E&P)	962	—	962	—
Tax impact on premium paid on early redemption of debt	(235)	—	(235)	—
Adjusted Operating Results	$ 42,237	$ 45,577	$ 288,764	$ 283,482
Reported GAAP Earnings per share	$ 0.44	$ 0.53	$ 4.53	$ 3.30
Items impacting comparability				
Remeasurement of deferred income taxes under 2017 Tax Reform	0.04	—	(1.20)	—
Premium paid on early redemption of debt, net of tax	0.01	—	0.01	—
Adjusted Operating Results per share	$ 0.49	$ 0.53	$ 3.34	$ 3.30

Non-GAAP Reconciliations – Capital Expenditures

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019 Forecast
Capital Expenditures						
Exploration & Production Capital Expenditures	$ 602,705	$ 557,313	$ 256,104	$ 253,057	$ 380,677	$460,000 - $495,000
Pipeline & Storage Capital Expenditures	$ 139,821	$ 230,192	$ 114,250	$ 95,336	$ 92,832	$120,000 - $150,000
Gathering Segment Capital Expenditures	$ 137,799	$ 118,166	$ 54,293	$ 32,645	$ 61,728	$55,000 - $65,000
Utility Capital Expenditures	$ 88,810	$ 94,371	$ 98,007	$ 80,867	$ 85,648	$90,000 - $100,000
Energy Marketing, Corporate & All Other Capital Expenditures	$ 772	$ 467	$ 397	$ 212	$ 222	
Eliminations	-	$ -	$ -	$ -	$ (20,505)	
Total Capital Expenditures from Continuing Operations	$ 969,907	$ 1,000,509	$ 523,051	$ 462,117	$ 600,602	$725,000 - $810,000
Plus (Minus) Accrued Capital Expenditures						
Exploration & Production FY 2018 Accrued Capital Expenditures					$ (51,343)	
Exploration & Production FY 2017 Accrued Capital Expenditures				$ (36,465)	$ 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 2018 Accrued Capital Expenditures					$ (21,861)	
Pipeline & Storage FY 2017 Accrued Capital Expenditures				(25,077)	$ 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 2018 Accrued Capital Expenditures					$ (6,084)	
Gathering FY 2017 Accrued Capital Expenditures				(3,925)	$ 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 2018 Accrued Capital Expenditures					$ (9,525)	
Utility FY 2017 Accrued Capital Expenditures				(6,748)	$ 6,748	
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)	$ (16,597)	
Total Capital Expenditures per Statement of Cash Flows	**$ 914,417**	**$ 1,018,179**	**$ 581,576**	**$ 450,335**	**$ 584,004**	**$725,000 - $810,000**

Non-GAAP Reconciliations – E&P Operating Expenses

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

	Twelve Months Ended September 30, 2018						Twelve Months Ended September 30, 2017					
	Appalachia	West Coast[2]	Total E&P	Appalachia $/ Mcfe	West Coast[2] $ / Boe	Total E&P $ / Mcfe	Appalachia	West Coast[2]	Total E&P	Appalachia $/ Mcfe	West Coast[2] $ / Boe	Total E&P $ / Mcfe
Operating Expenses:												
Gathering & Transportation Expense [1]	$95,611	$46	$95,657	$0.60	$0.02	$0.54	$92,874	$502	$93,376	$0.60	$0.16	$0.54
Other Lease Operating Expense	$14,604	$52,461	$67,065	$0.09	$17.89	$0.38	$16,625	$55,990	$72,615	$0.11	$17.31	$0.42
Lease Operating and Transportation Expense	$110,215	$52,507	$162,721	$0.69	$17.91	$0.91	$109,499	$56,492	$165,991	$0.71	$17.46	$0.96
General & Administrative Expense			$60,596			$0.34			$58,734			$0.34
All Other Operating and Maintenance Expense			$11,077			$0.06			$13,469			$0.08
Property, Franchise and Other Taxes			$14,400			$0.08			$15,426			$0.09
Total Taxes & Other			$25,477			$0.14			$28,895			$0.17
Depreciation, Depletion & Amortization			$124,274			$0.70			$112,565			$0.65
Production:												
Gas Production (MMcf)				160,499	2,407	162,906				154,093	2,995	157,088
Oil Production (MBbl)				4	2,531	2,535				4	2,736	2,740
Total Production (Mmcfe)				160,523	17,592	178,114				154,117	19,411	173,528
Total Production (Mboe)				26,754	2,932	29,686				25,686	3,235	28,921

(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.