Investor Presentation

Q2 Fiscal 2020 Update

April 30, 2020

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
Environmental protection and conservation of resources are high priorities for National Fuel. We utilize procedures, technologies, and best management practices to develop, build, and operate our assets in a manner that respects and protects the environment.

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 focuses on the highest standards of corporate responsibility and accountability.

Transparency
We believe that open communication is key to 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

A message from David Bauer, President and CEO of National Fuel Gas Company, on NFG's COVID-19 response

"As we confront the challenges of the COVID-19 pandemic, I am proud to say that National Fuel has continued to safely and reliably provide natural gas service to our over 743,000 utility customers in western New York and northwestern Pennsylvania, operate our extensive network of transportation, compression and gathering infrastructure, and produce critical natural gas supplies.

The continuity of our operations is a direct result of the dedication and hard work of our over 2,000 employees. During this unprecedented situation, National Fuel has remained committed to our workforce - the bedrock of our Company - and has not instituted any furloughs or workforce reductions. With a large portion of our employees now working remotely, we have implemented a number of initiatives to provide the flexibility needed to address this new normal, including additional paid time off to address child care needs, and encouraging the use of alternative work schedules.

With respect to our in-field workforce and customer service representatives, all of whom provide essential services to our communities each and every day, we have adopted appropriate social distancing measures and have provided necessary personal protective equipment in line with directives from federal, state, and local agencies. As this public health crisis evolves, the health and well-being of our employees and our communities will remain our number one priority, and National Fuel will continue to monitor developments affecting our stakeholders in order to take appropriate steps to mitigate the impacts of the COVID-19 virus."

NFG: A Diversified, Integrated Natural Gas Company

National Fuel®

Upstream
Exploration & Production

44% of NFG EBITDA(1)

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

~785,000 Net acres in Appalachia

~610 MMcf/day Net Appalachian natural gas production

Midstream
Gathering Pipeline & Storage

36% of NFG EBITDA(1)

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

$1.7 Billion Investments since 2010

3.9 MMDth Daily interstate pipeline capacity under contract

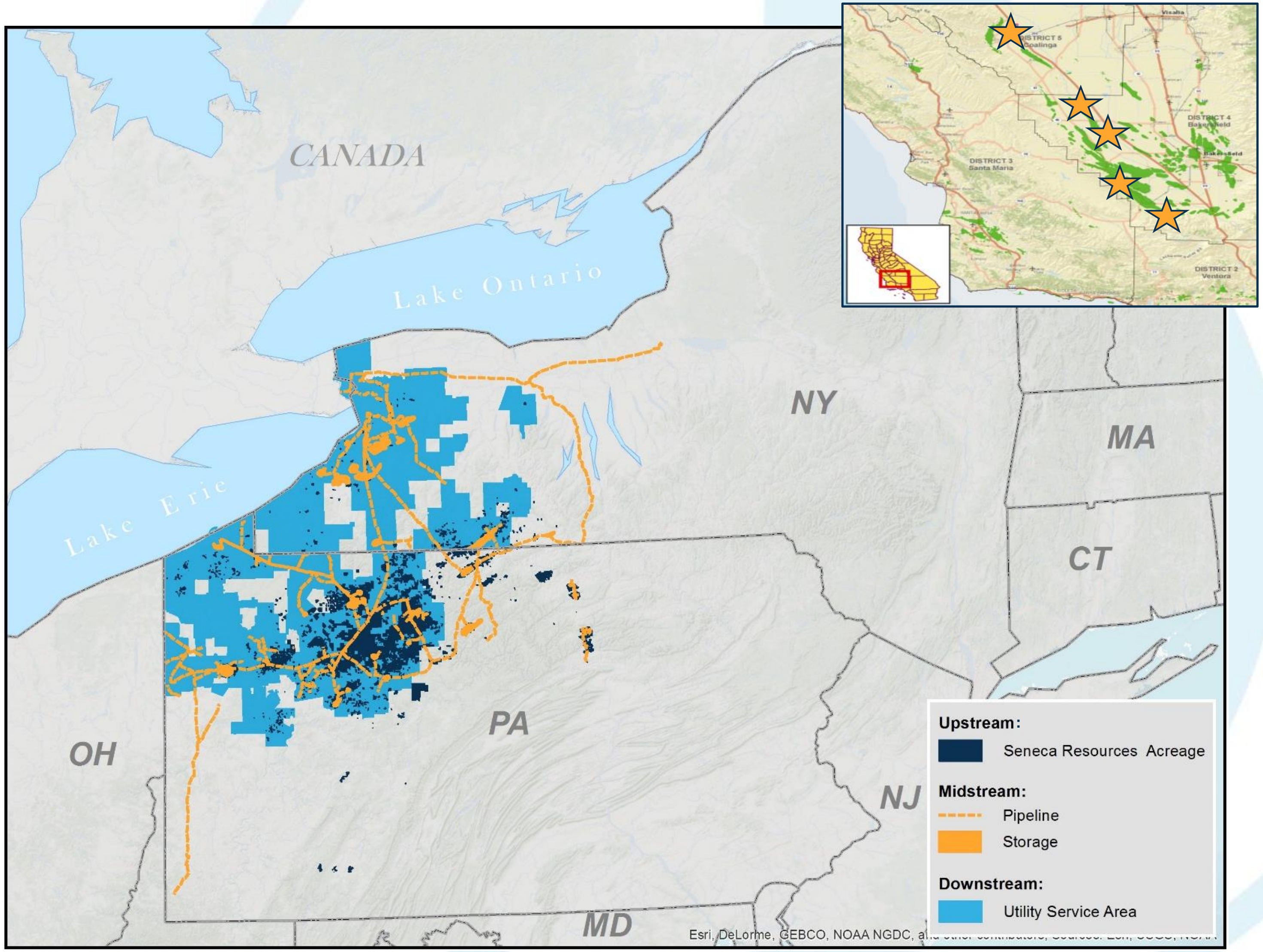
Downstream
Utility

20% of NFG EBITDA(1)

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

743,400 Utility customers

$324 Million Investments in safety since 2015



(1) This presentation includes forward-looking statements. Please review the safe harbor for forward looking statements in the appendix of this presentation.
(2) Twelve months ending March 31, 2020. 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.

Why National Fuel?

Diversified Assets Provide Stability and Long-Term Growth Opportunities

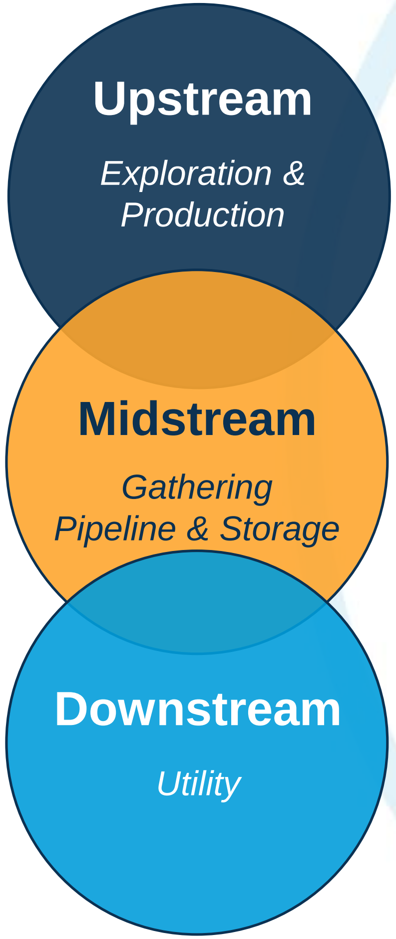
1. **Integrated Model Enhances Shareholder Value**
2. **Long History of Returning Capital to Shareholders**
3. **Maintaining Focus on Balance Sheet Through Responsible Capital Allocation**
4. **Utilization of Existing Infrastructure Amplifies Consolidated Returns**
5. **$1 Billion+ Pipeline & Storage Project Backlog**

1 Integrated Model Enhances Shareholder Value . . .

National Fuel

Benefits of National Fuel's Integrated Structure:

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



Geographic and Operational Integration Drives Synergies:

Upstream → Midstream

- ✓ Co-Development of Marcellus and Utica
- ✓ Just-in-time gathering facilities
- ✓ Pipeline expansion opportunities

Midstream → Downstream

- ✓ Rate-regulated entities share common resources, reducing operating expense
- ✓ Utility business is a large Pipeline & Storage customer

Financial Efficiencies:

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

. . . and Drives Organic Growth Opportunities

National Fuel

Near Term Strategy Leverages Integration Across the Value Chain

Exploration & Production → Gathering → Pipeline & Storage → Utility

- ✓ **Integrated Upstream and Midstream development of 785,000 acre Marcellus and Utica shale position**
  - Drilling program focused on return trips to existing pads and use of existing infrastructure
  - NFG Gathering transports 100% of natural gas production, driving consolidated returns
  - NFG pipeline expansions under development create new firm takeaway capacity for E&P business
- ✓ **Further expansion of interstate pipeline systems to satisfy growing natural gas supply and demand**
  - *Supply push* – Appalachian producers
  - *Demand pull* – regional demand-driven projects and utilities
- ✓ **Ongoing investment in safety and modernization of pipeline transportation and distribution systems**
  - $500+ million in new investments expected over the next 5 years

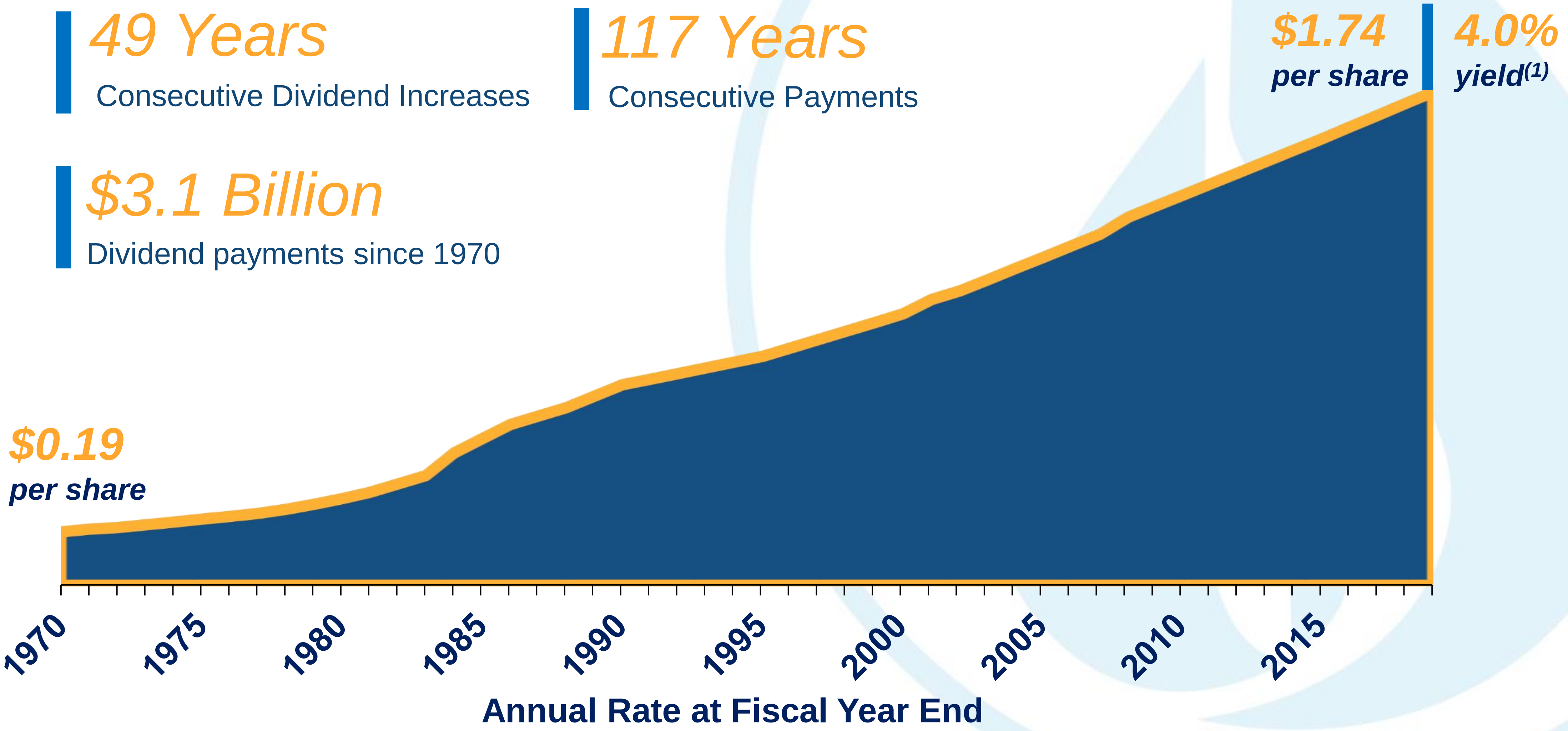
2 Impressive Dividend History

National Fuel®

49 Years
Consecutive Dividend Increases

117 Years
Consecutive Payments

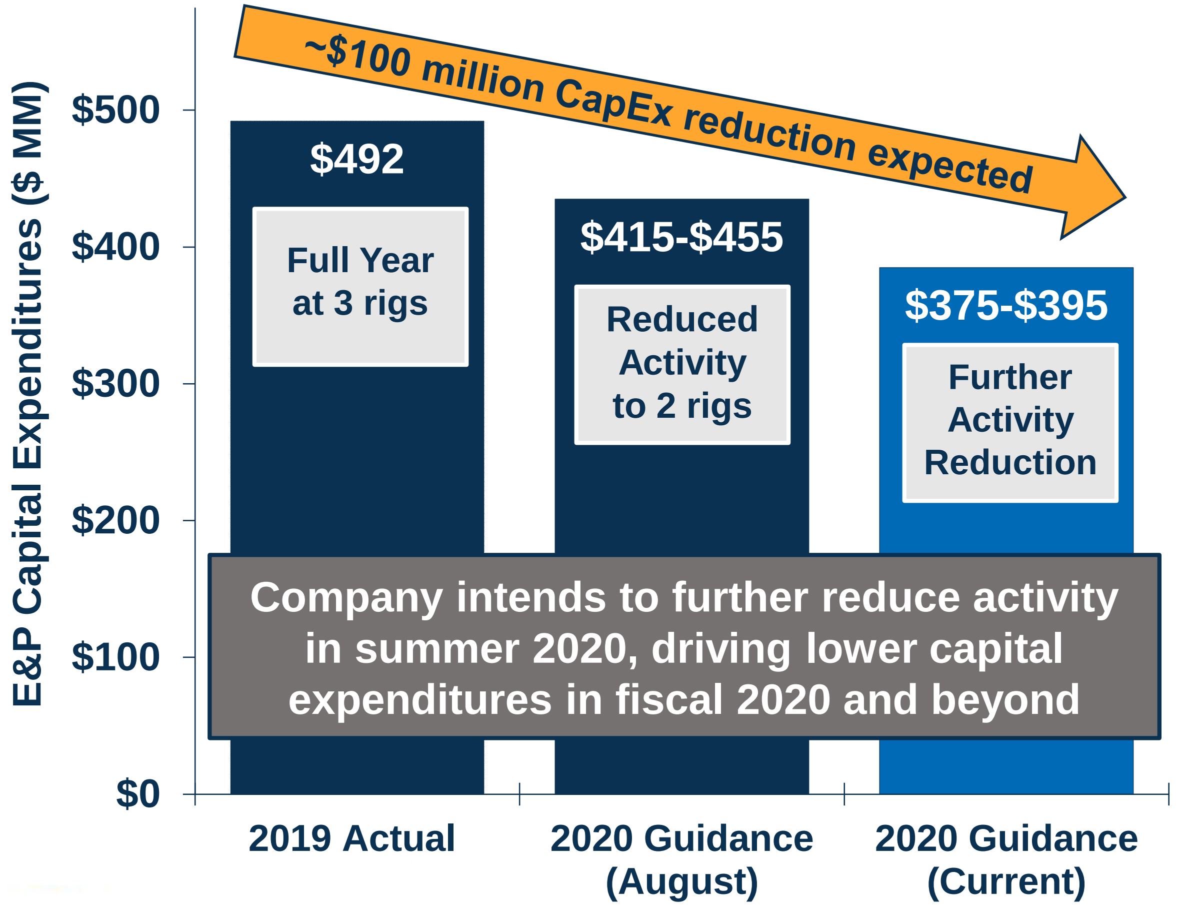
$3.1 Billion
Dividend payments since 1970



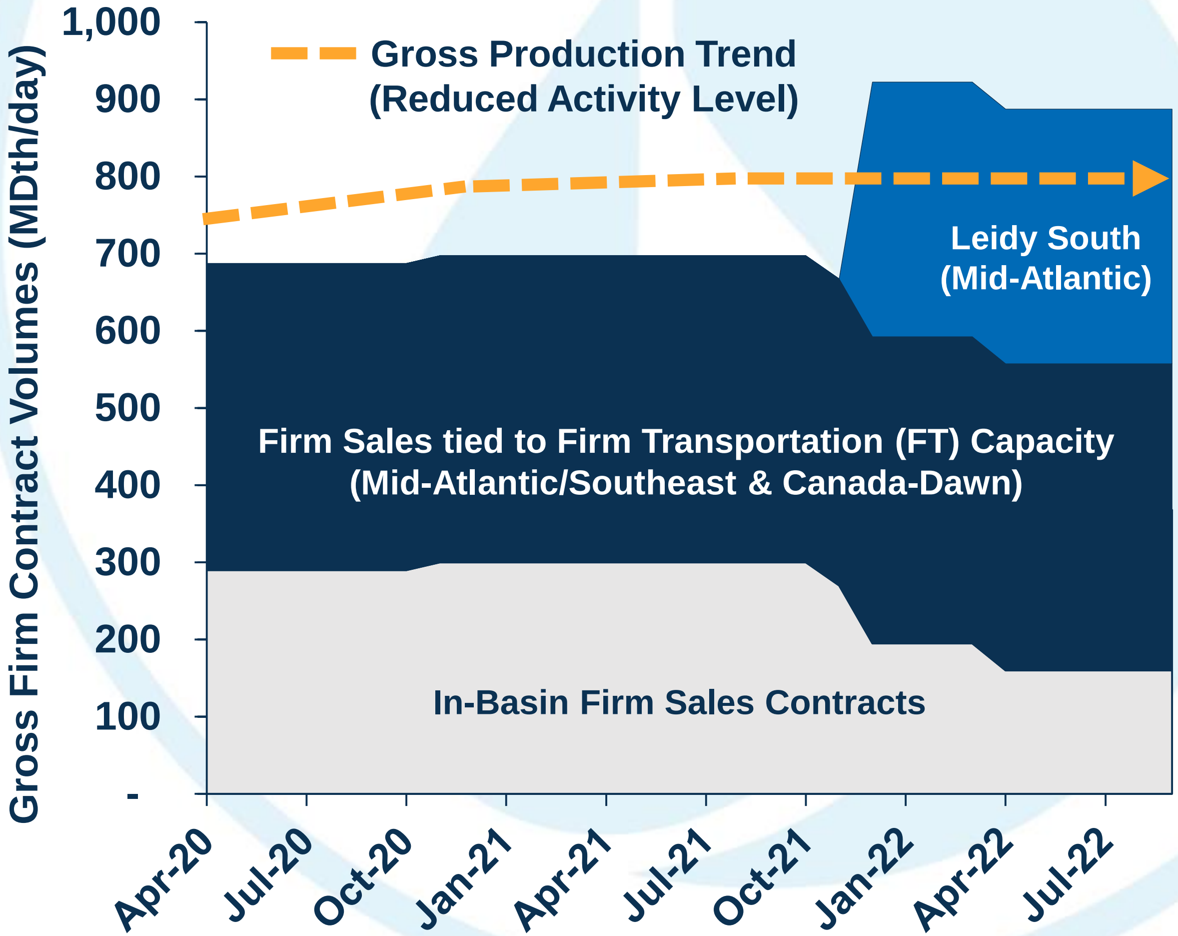
(1) As of April 29, 2020.

3 Responsible Capital Allocation and Asset Development

Maintaining Focus on Balance Sheet, With Significant Reductions in E&P Activity Level and Capital Expenditures . . .



. . . While Generating Steady Production, and Optimizing Significant Firm Sales Portfolio and Firm Transportation Capacity



4 Leveraging Existing Infrastructure to Enhance Returns

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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)

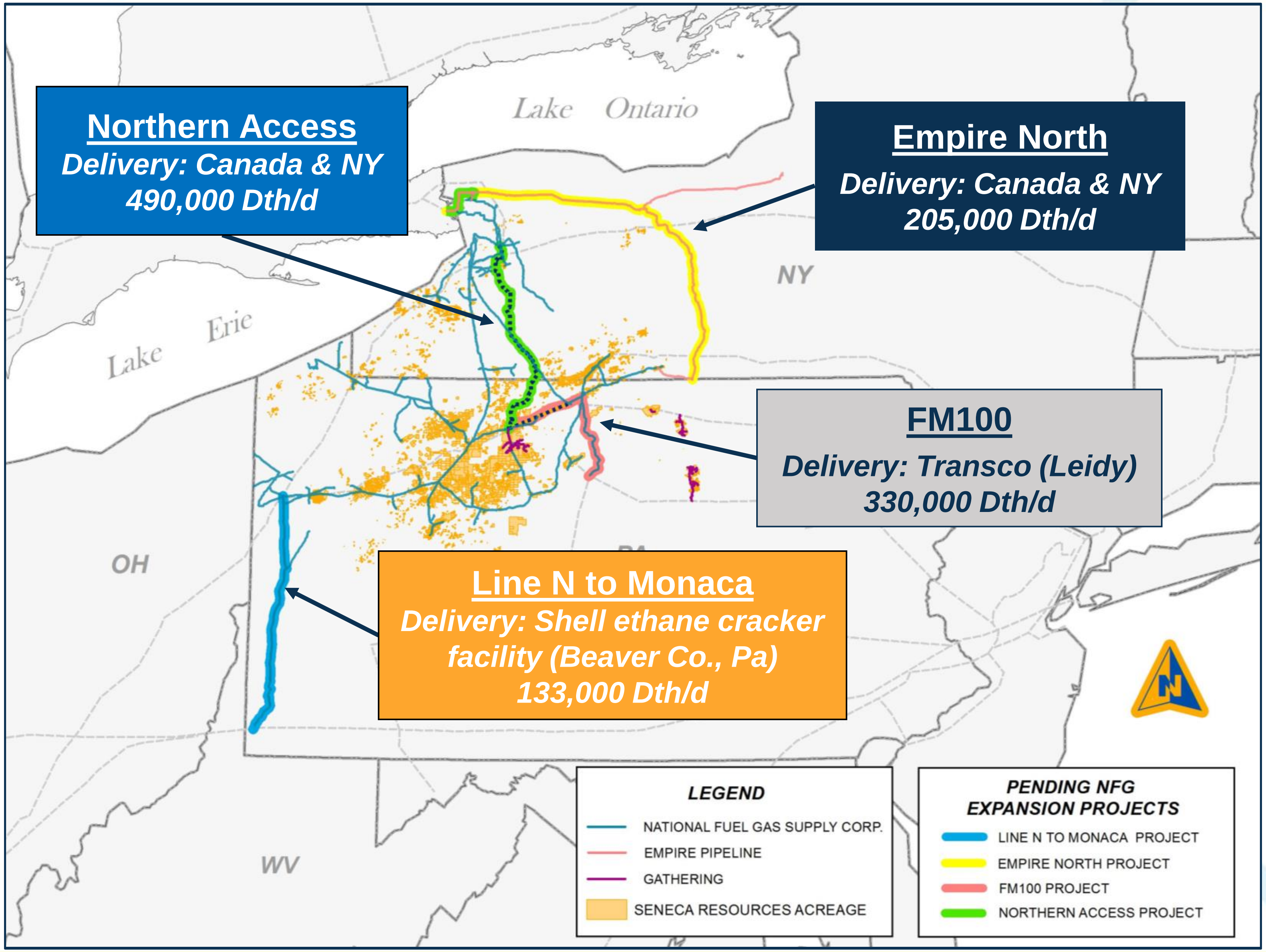
	Gathering CapEx/Well ($ thousands)
Marcellus (pre-2019)	$1,489[1]
Utica Return Trips (current)	~$430[2]

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

~10% IRR Uplift Expected[3]

(1) Approximate WDA Marcellus gathering facility costs for 192 wells drilled and completed as of September 30, 2018.
(2) Estimated WDA Utica gathering facility costs for remaining return trip locations in the 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 for remaining return trip locations, well costs under current cost structure, and non-gathering LOE.

5 Significant Interstate Pipeline Backlog



✓ **Significant Expected Near-Term Expansion Revenues:**

- **Line N to Monaca:** $5 MM (*placed into service 11/1/19*)
- **Empire North:** $25 MM
- **FM100:** $35 MM

✓ **Substantial Modernization Opportunities:**

- $150-$250 million expected over next 5 years (Supply Corp.)

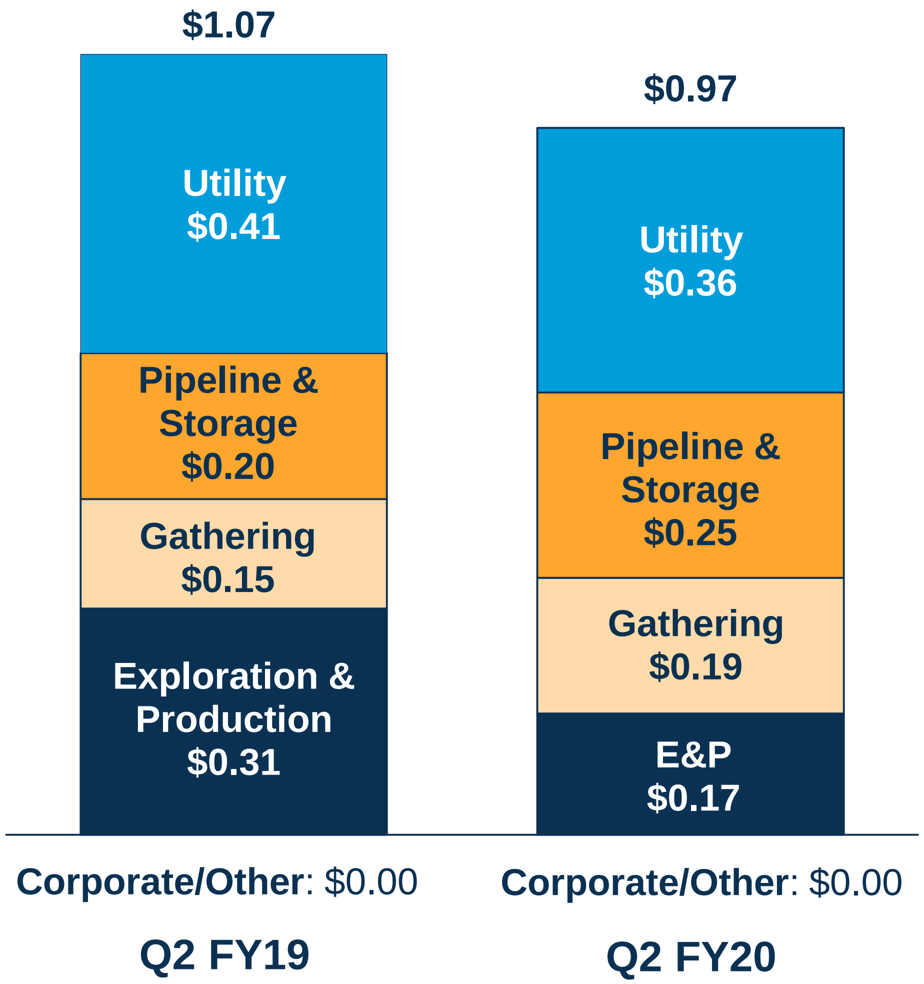
✓ **Northern Access project remains under development**

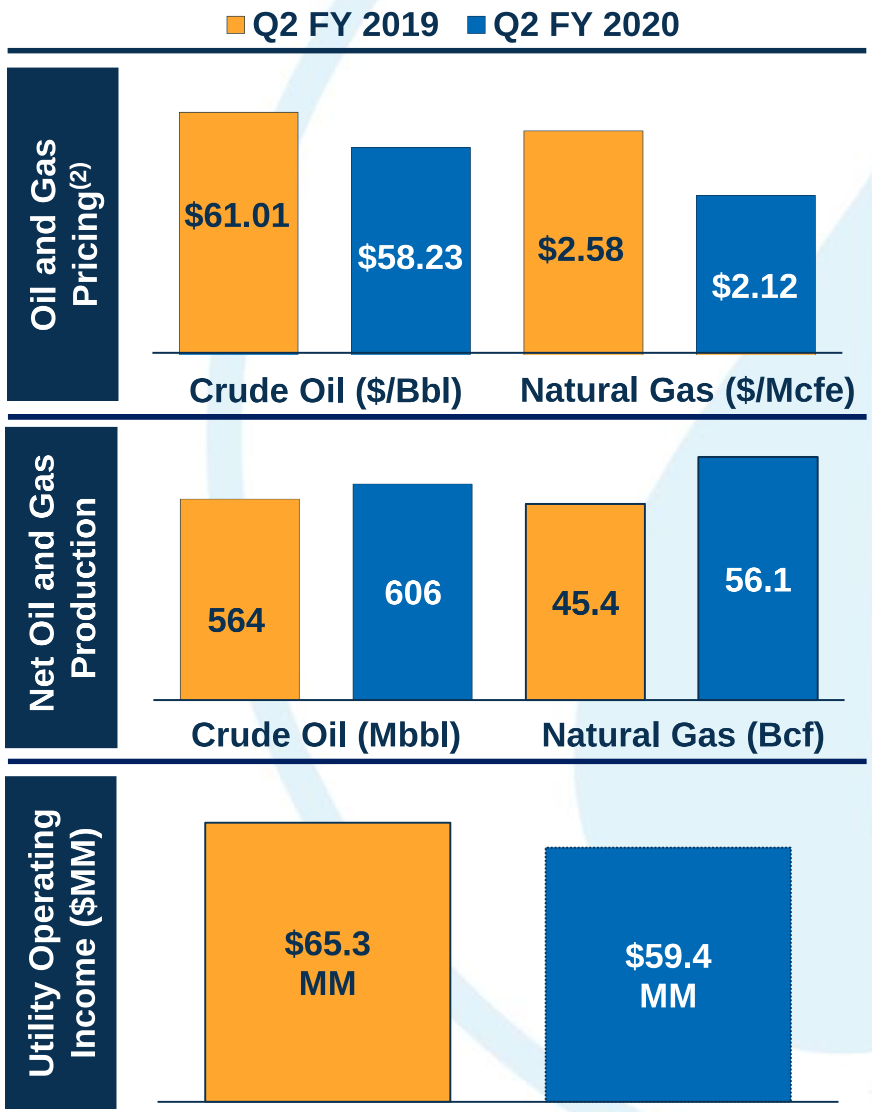
Second Quarter Fiscal 2020

Financial Highlights

Second Quarter Fiscal 2020 Results and Drivers

Adjusted Operating Results ($/share)(1)





Major Drivers

- ↓ Natural Gas Prices
- ↓ Oil Prices
- ↑ Natural Gas Production
- ↑ Oil Production
- ↓ Warmer than Normal Weather (PA territory)

(1) Adjusted Operating results of $1.07 for Q2 FY19 and $0.97 for Q2 FY20 include operating results of Corporate & All Other Segments segment. A Reconciliation of Adjusted Operating Results to Earnings Per Share is provided at the end of this presentation.
(2) Realized price after hedging.

Earnings Guidance – Reduction Driven by Commodity Prices

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Key Guidance Drivers		FY2019 Adjusted Operating Results: $3.45/share[1]	FY2020 Earnings Guidance: $2.75 to $2.95/share
Non-regulated Businesses *Exploration & Production* *Gathering*	↑	**Production & Gathering Throughput**	▪ Seneca Net Production: 230 to 240 Bcfe ▪ Gathering Revenues: $135-$140 million
	↓	**Realized natural gas prices (after-hedge)**	▪ Natural Gas: ~$2.05/Mcf[2] *(vs. $2.44/Mcf in FY 2019)*
	↔	**Realized oil prices (after-hedge)**	▪ Crude Oil: ~$55.00/Bbl[3] *(vs. $61.65/Bbl in FY 2019)*
	↔	**DD&A Expense**	▪ Guidance of $0.70 - $0.74/Mcf (*vs. $0.73 in FY 2019)*
Regulated Businesses *Pipeline & Storage* *Utility*	↑	**Pipeline & Storage Revenues**	▪ ~$305 million *(Supply rate case and expansion project impacts partially offset by Empire contract expiration)*
	↓	**Pipeline & Storage Pension Costs and Depreciation Expense**	▪ Pension: Expected to increase by ~$4 million from FY19 ▪ Depreciation: Expected to increase by ~$9 million from FY19
	↓	**Utility Operating Income**	▪ Warmer than normal weather in Q2 FY20 and cost inflation, partially offset by system modernization
Tax Rate	↓	**Higher effective tax rate**	▪ Effective tax rate ~26% *(enhanced oil recovery credit unavailable in FY2020)*

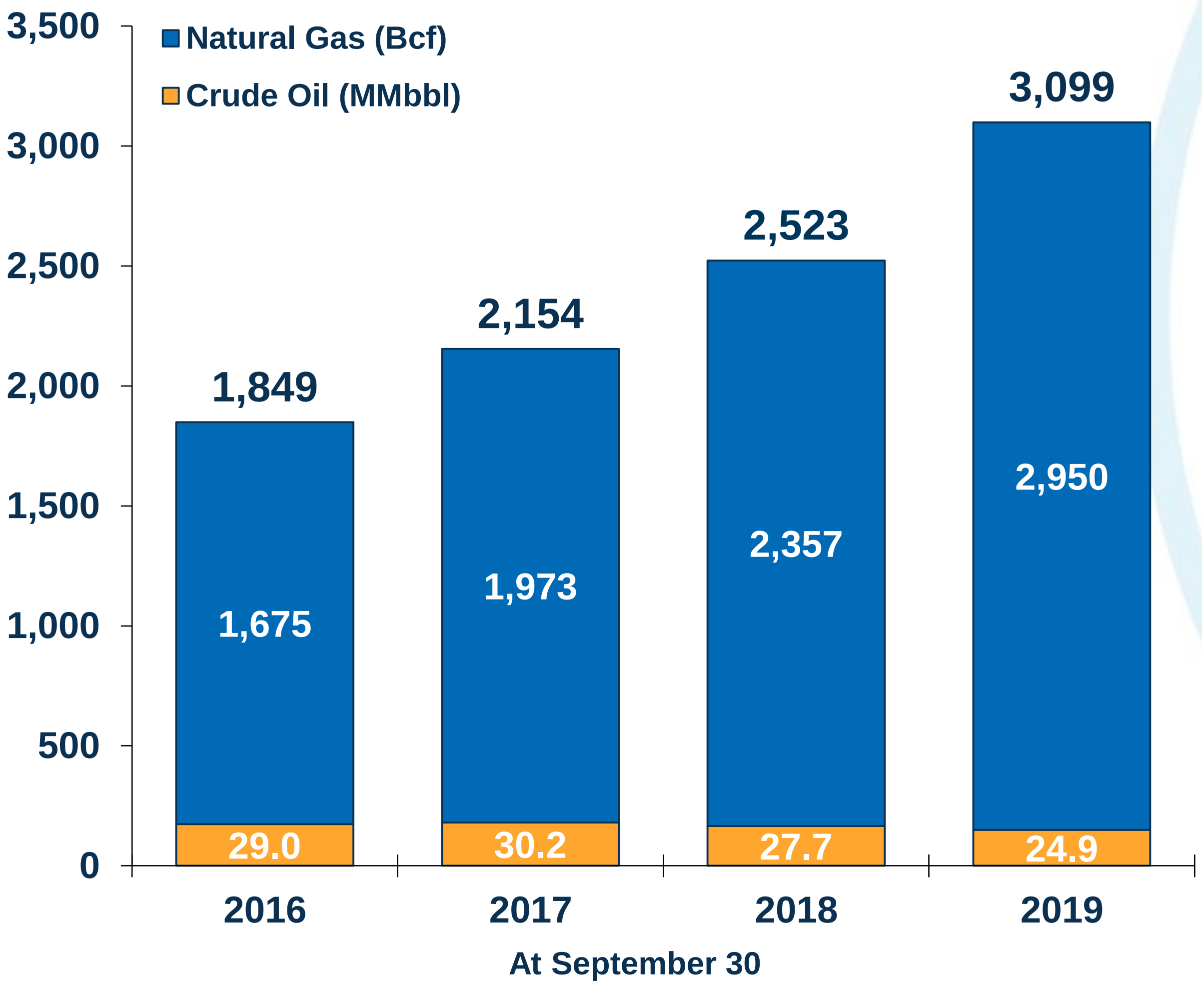
(1) Excludes items impacting comparability. A reconciliation of Adjusted Operating Results is provided at the end of this presentation.
(2) Assumes NYMEX natural gas pricing of $2.05/MMBtu and in-basin spot pricing of $1.65/MMBtu for the remainder of fiscal 2020, and reflects the impact of existing financial hedges, firm sales and firm transportation contracts.
(3) Assumes NYMEX (WTI) oil pricing of $22.50/Bbl and California-MWSS pricing differentials of 90% to WTI, and reflects impact of existing financial hedge contracts.

Exploration & Production and Gathering Overview

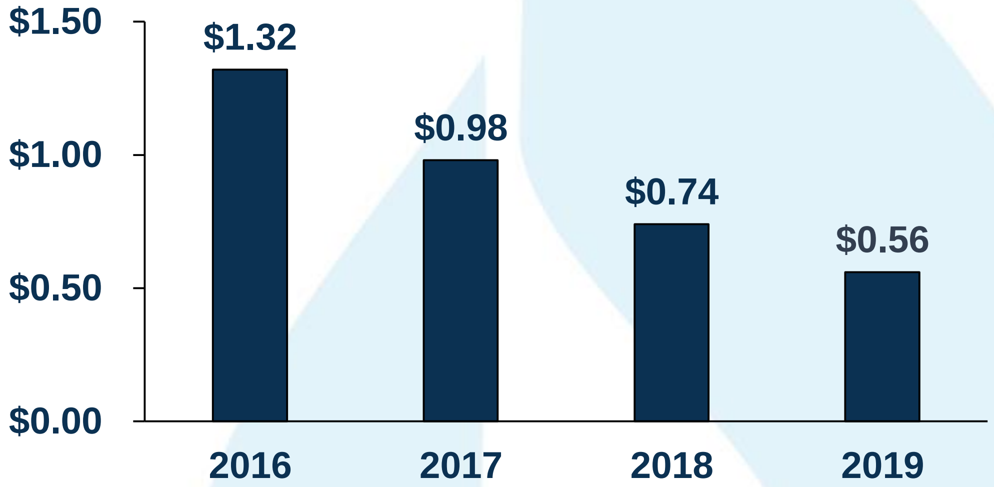
Seneca Resources Company, LLC ~ National Fuel Gas Midstream Company, LLC

Proved Reserves

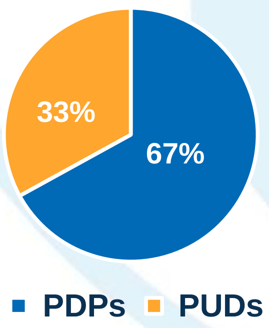
Total Proved Reserves (Bcfe)



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



Fiscal 2019 Proved Reserves Stats

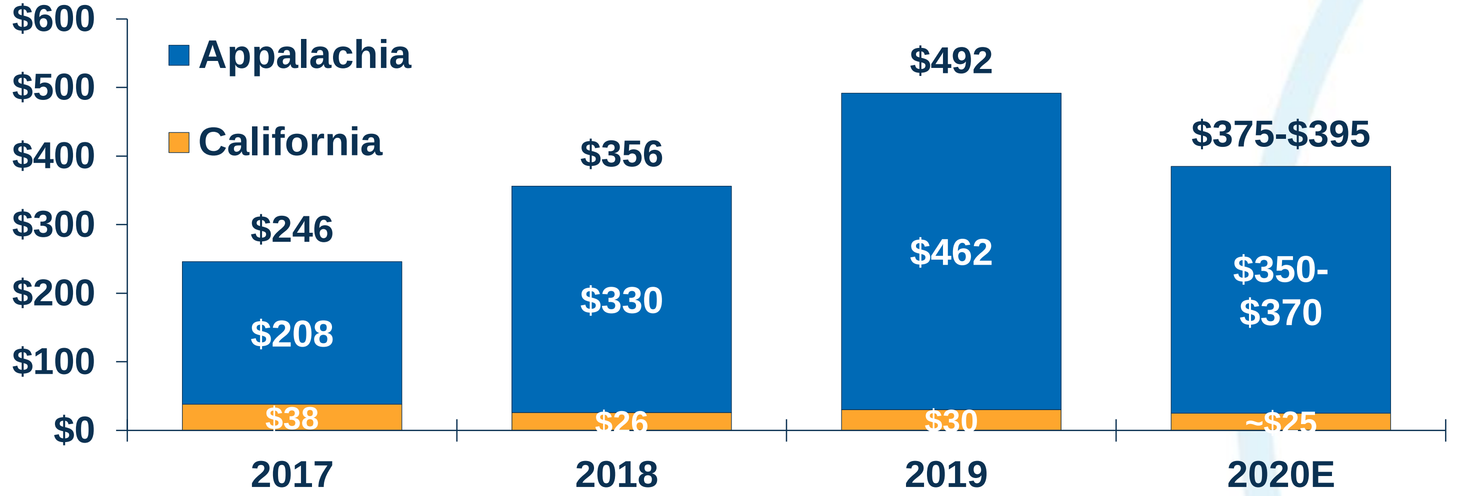


- 372% Reserve Replacement Rate
- Seneca Drill-bit F&D = $0.67/Mcfe[(1)]
- Appalachia Drill-bit F&D = $0.62/Mcfe[(1)]

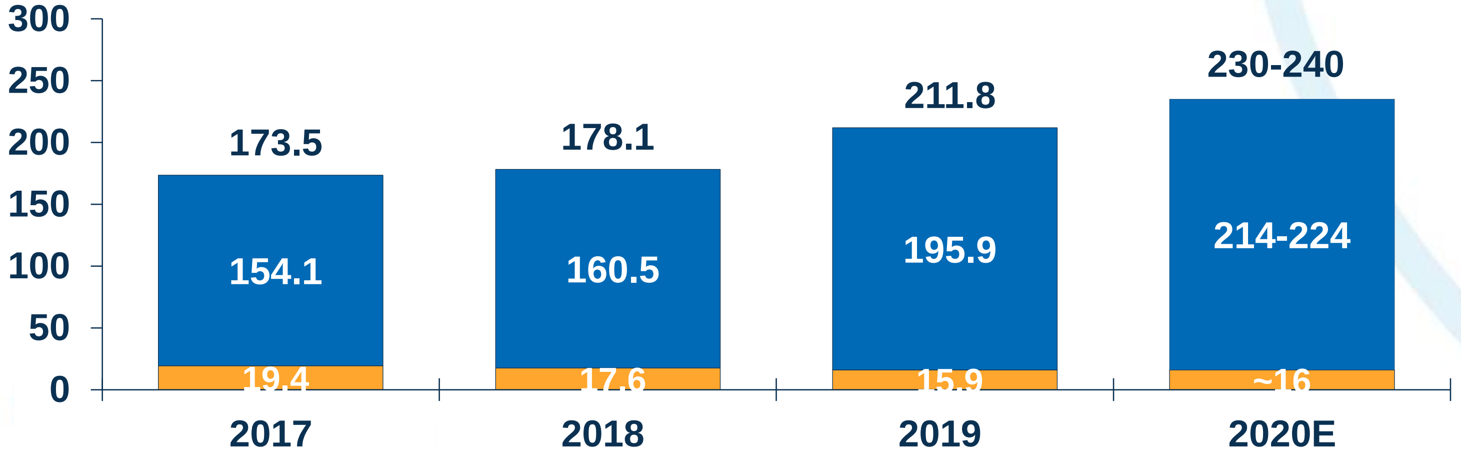
(1) Seneca "Drill-bit" finding and development ("F&D") costs exclude the impact of reserve revisions. Seneca Drill-Bit F&D and Appalachia Drill-Bit F&D are 3-year averages.

Growing Production within Disciplined Capital Program

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



E&P Net Production (Bcfe)



Near-Term Strategy

- ✓ Further reduce activity to 1-rig development program in summer 2020 (moved from 3 to 2 rigs in January 2020)
- ✓ Development focused in WDA-Utica, with EDA activity focused on utilizing valuable firm transportation and sales contracts
  - Gross production growth will benefit NFG's Gathering segment
- ✓ Layer in additional firm sales in advance of new firm transportation capacity expected in late 2021 (Leidy South)

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

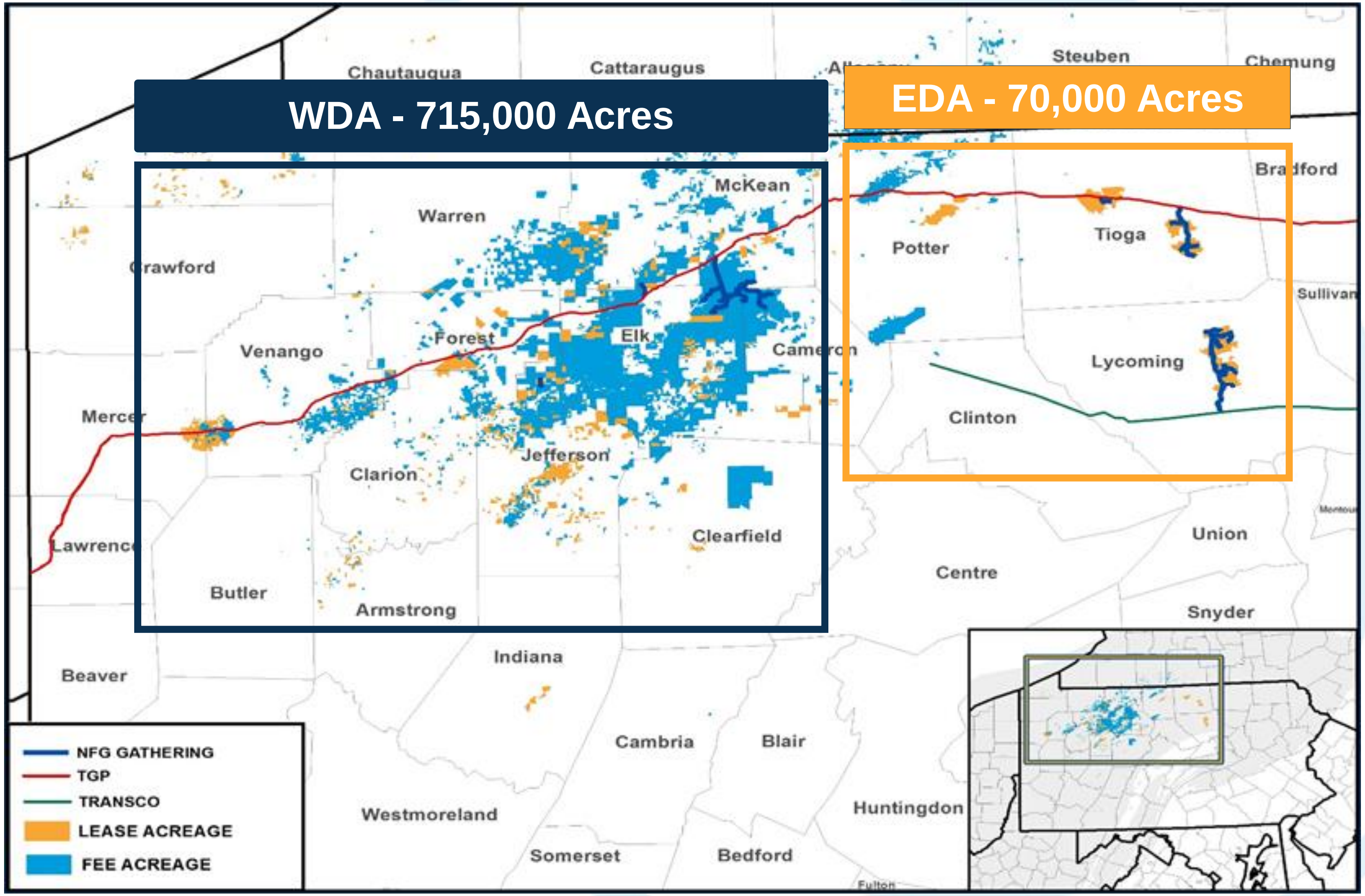
Significant Appalachian Acreage Position

Western Development Area (WDA)

- Average gross production[1]: ~362 MMcf/d
- Over 1,000 potential Marcellus & Utica locations
- ~90 locations where gathering/pad infrastructure in place from prior drilling activities, driving returns:
  - Breakeven (15% IRR) consolidated economics of $1.60 or less
- Royalty free mineral ownership
- Highly contiguous nature drives efficiencies

Eastern Development Area (EDA)

- Average gross production[1]: ~380 MMcf/d
- Mostly leased (16-18% royalty) with no significant near-term lease expirations
- ~70 remaining Marcellus & Utica locations:
  - Breakeven (15% IRR) consolidated economics of $1.40 or less
- Additional Marcellus (Tioga Co.) & Geneseo (Lycoming Co.) potential



(1) Average EDA and WDA gross production, as well as WDA-CRV Utica and Marcellus production (see slide 20), and Covington/Tract 595 Production (see slide 24), is for the quarter ended March 31, 2020.

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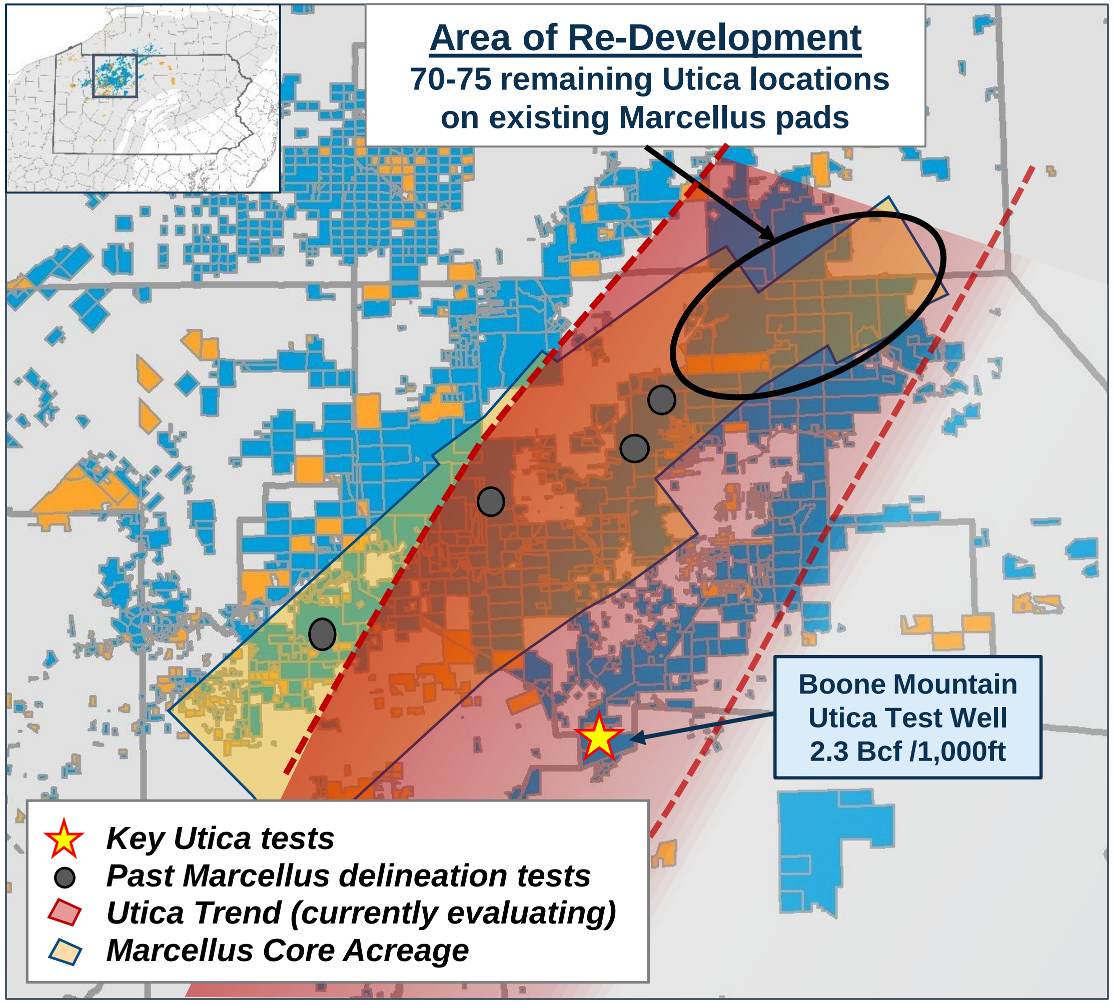
Western Development Area

Marcellus Core Acreage vs. Utica Appraisal Trend(1)



WDA Highlights

- ✓ **Large well inventory:**
  - 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**
- ✓ **Use of existing gathering, pad, and water infrastructure for Utica drives increased Appalachian program returns**
- ✓ **Highly contiguous position drives best in class well costs**
- ✓ **Long-term firm contracts support growth**
- ✓ **Additional appraisal tests planned to delineate the Rich Valley to Boone Mountain corridor**

(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 is expected to do the same.

WDA-CRV Results and Type Curves

WDA-CRV Development Update

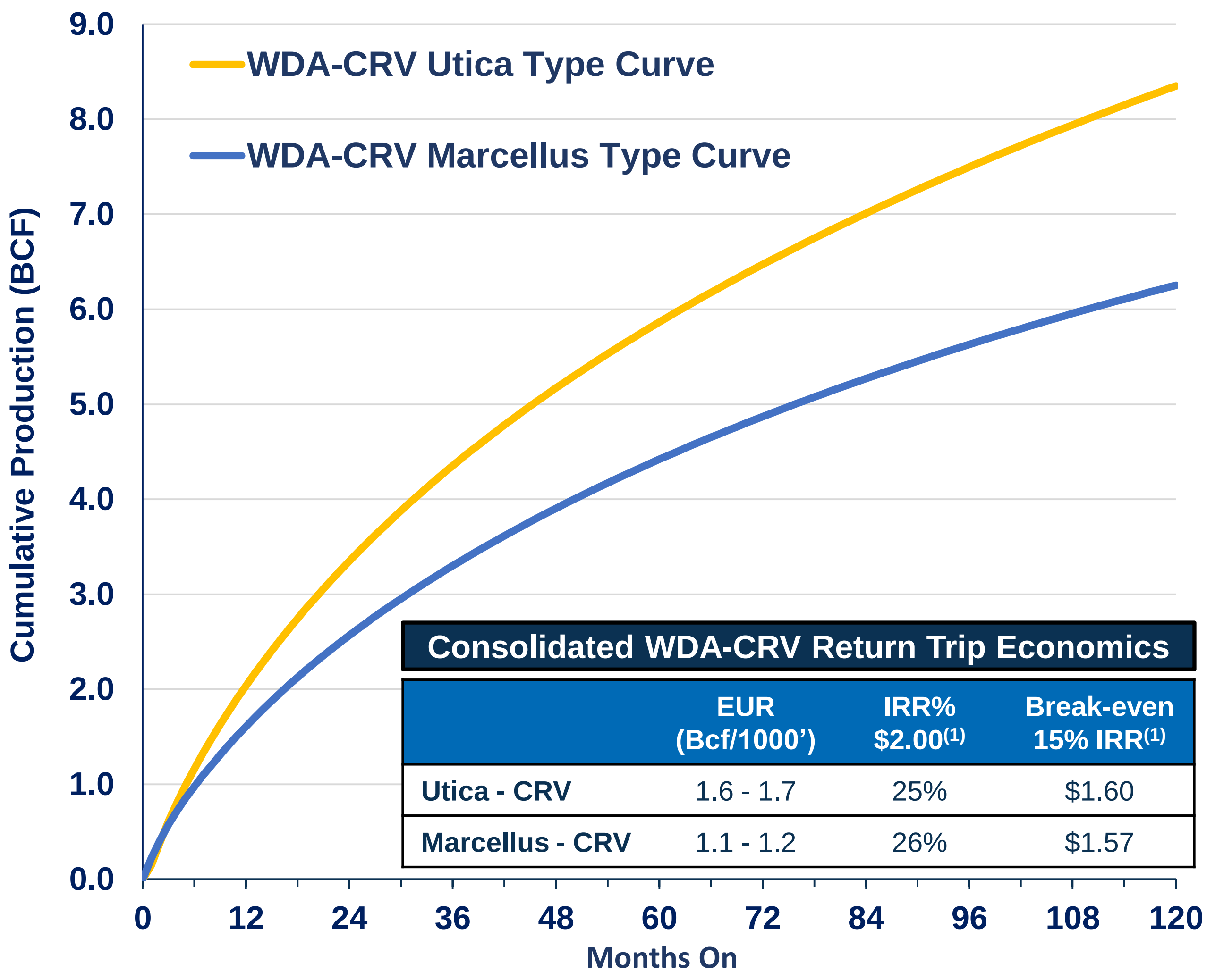
- ✓ **Tested / currently producing from 35 Utica wells in WDA-CRV area**
  - Avg. CRV Utica Production: ~105 MMCf/d
  - Avg. CRV Marcellus Production: ~227 MMcf/d
- ✓ **Drawdown management and produced fluid blend percentage are critical to well productivity**

WDA-CRV Utica Development Plan

- ✓ **Continue Optimizing Utica D&C completion design, focusing on:**
  - Proppant loading
  - Stage spacing
  - Produced fluid blend
- ✓ **Tailor development plan to use existing pad, water and gathering infrastructure**

(1) Internal Rate of Return is for consolidated Seneca and Gathering, is pre-tax, and includes expected gathering capital expenditures for remaining return trip locations, well costs under current cost structure, and non-gathering LOE.

WDA-CRV Types Curves – Normalized to 9,000’



Consolidated WDA-CRV Return Trip Economics

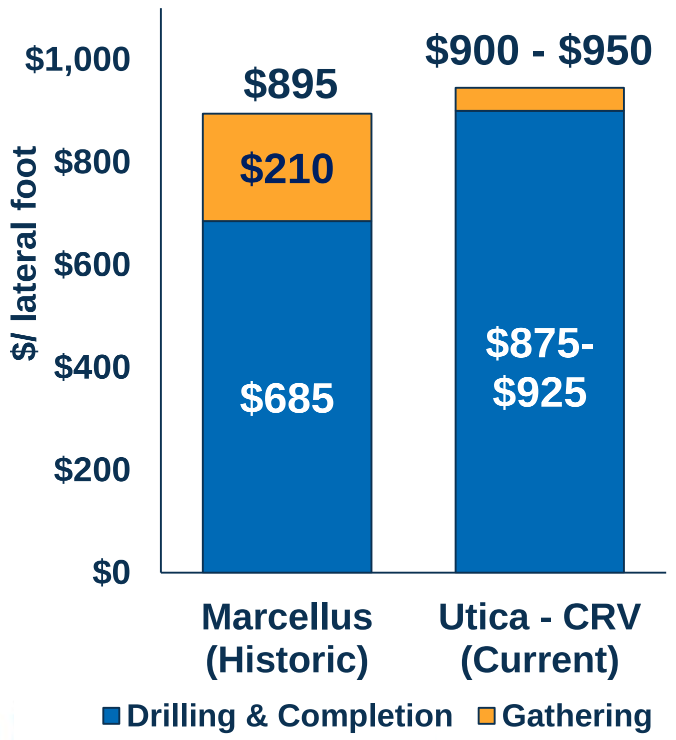
	EUR (Bcf/1000’)	IRR% $2.00[1]	Break-even 15% IRR[1]
Utica - CRV	1.6 - 1.7	25%	$1.60
Marcellus - CRV	1.1 - 1.2	26%	$1.57

Limited New Infrastructure Needed to Support Production Growth

Leveraging Existing Gathering, Water and Pad Infrastructure Enhances Returns

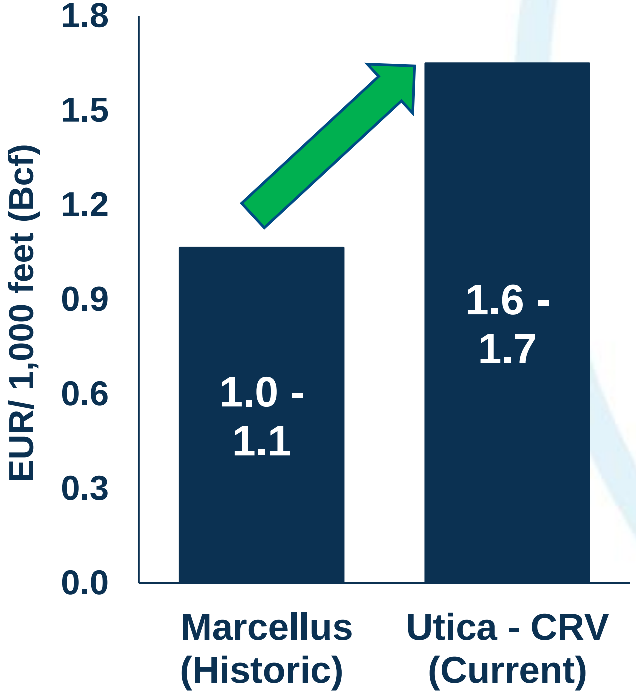
WDA Well Costs[1]

Total cost per well expected to marginally increase



WDA EURs

~60% EUR increase expected per well



WDA-CRV Consolidated Economics

Coordination between upstream and midstream activities enhances returns, provides economies of scale and significant operational flexibility

~10% IRR Uplift Expected

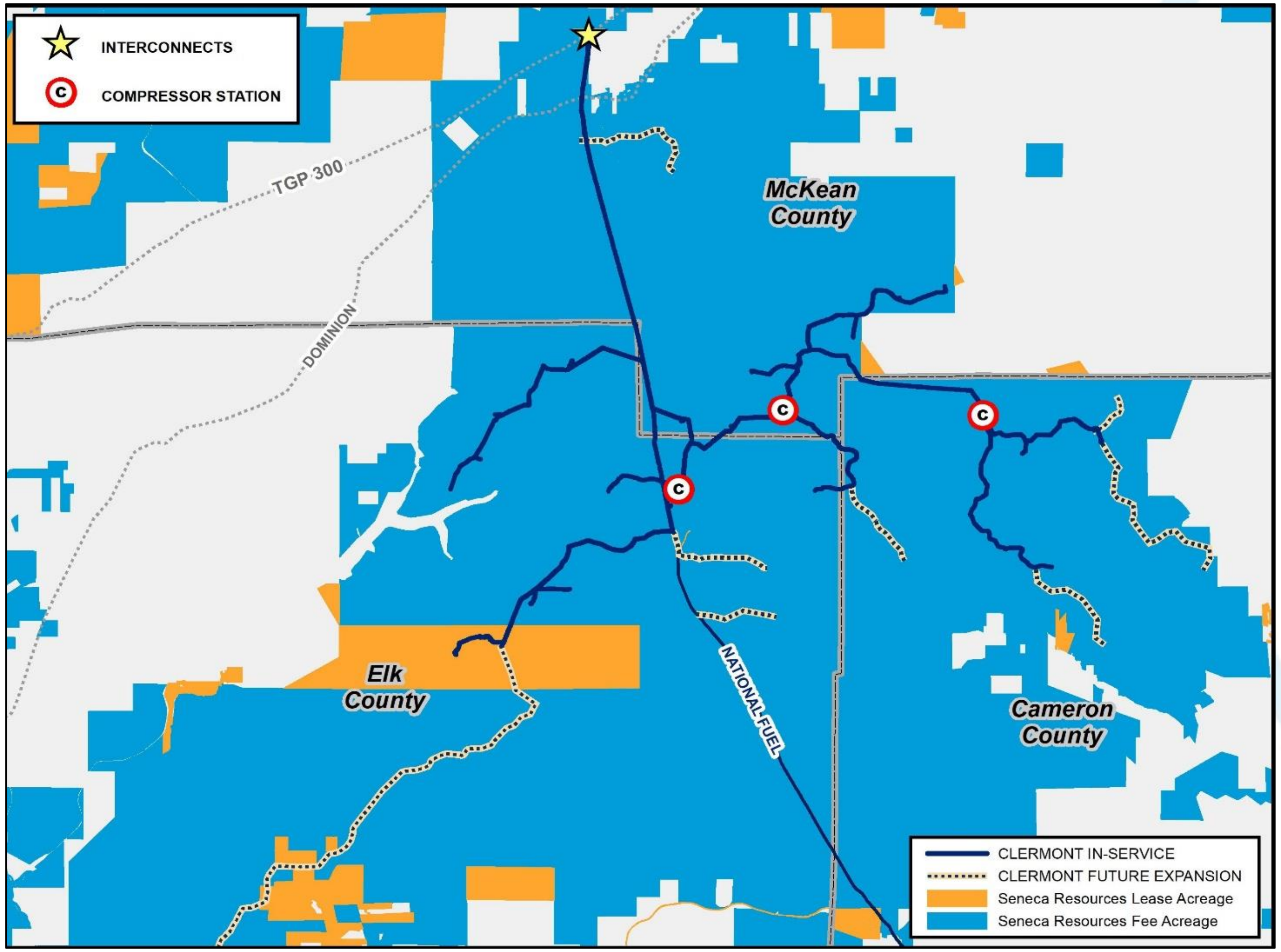
At a $2.00 netback price, consolidated Seneca WDA and Gathering IRR is approximately 25%, an uplift of ~10% over standalone Seneca WDA economics[2]

(1) WDA Marcellus well costs reflect drilling, completion & gathering costs for 192 drilled and completed wells as of 9/30/18. WDA-CRV Utica well costs reflect expected drilling, completion & gathering costs for the remaining 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 for remaining return trip locations, 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

- Capacity: 470 MMcf per day
- Interconnects with TGP 300 and NFG Supply
- Total Investment to Date: $310 million
- 38,120 HP of compression (3 stations)

Future Build-Out

- Modest gathering pipeline and compression investment required to support Seneca's Utica return-trip development
- Opportunity for 300 miles of pipelines and six compressor stations (+60,000 HP installed) as Seneca's drilling activity continues

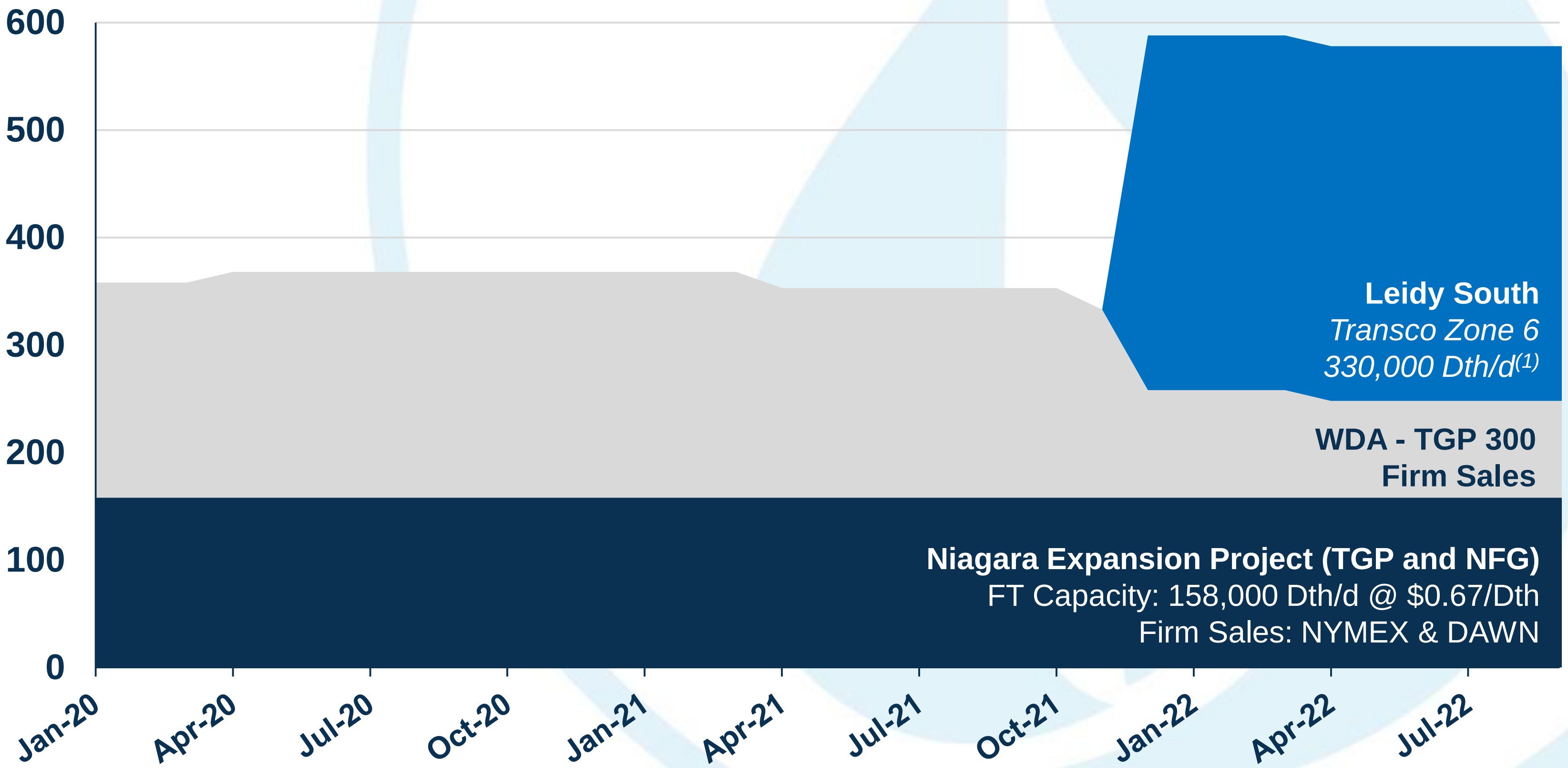
WDA Firm Transportation and Sales Capacity

WDA Exit Capacity Supports Production and Enhances 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¢ - 20¢ 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 Leidy South 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
- 35-40 remaining Utica locations
- Gathering infrastructure: NFG Midstream Wellsboro
- Marcellus Shale expected to provide ~60 additional locations

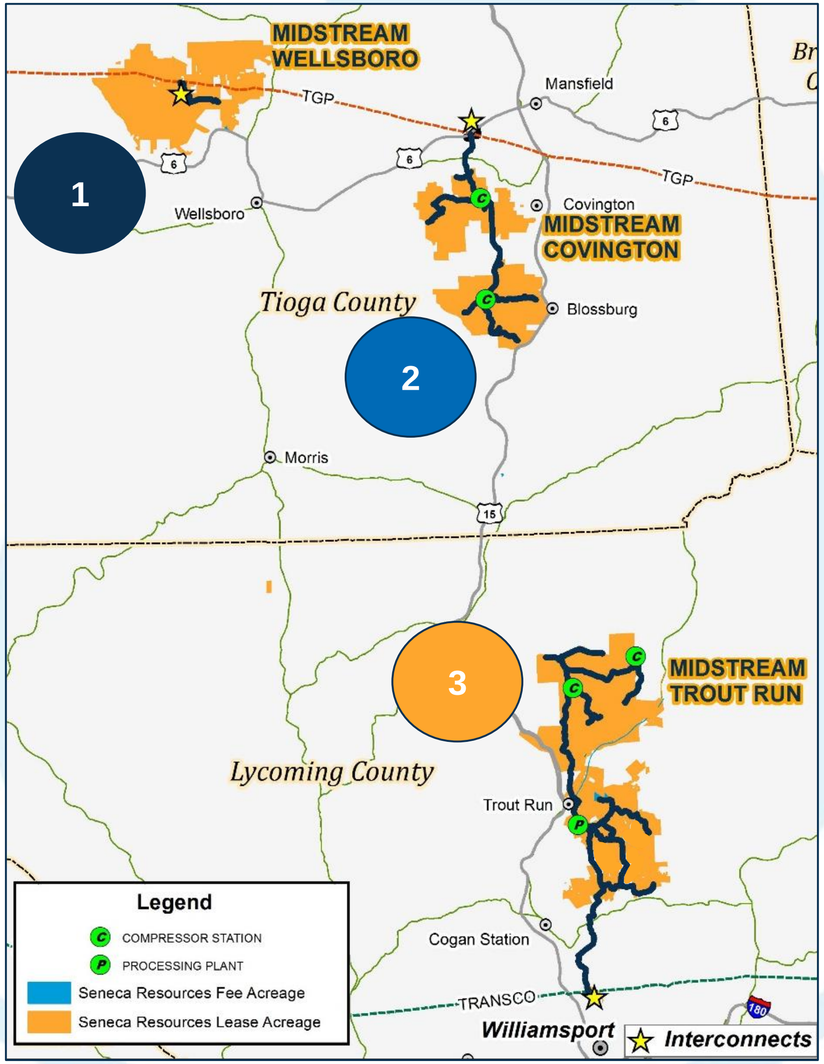
2 Covington & DCNR Tract 595 (Tioga Co., Pa.)

- Marcellus locations fully developed (average daily gross production of ~72 MMcf/d)
- Gathering infrastructure: NFG Midstream Covington
- Opportunity for future Utica appraisal

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

- 30-35 remaining Marcellus locations
- Firm transportation capacity: Atlantic Sunrise (189 MDth/d)
- Gathering infrastructure: NFG Midstream Trout Run
- Geneseo Shale expected to provide 100 - 120 additional locations

EDA Acreage – 70,000 Acres



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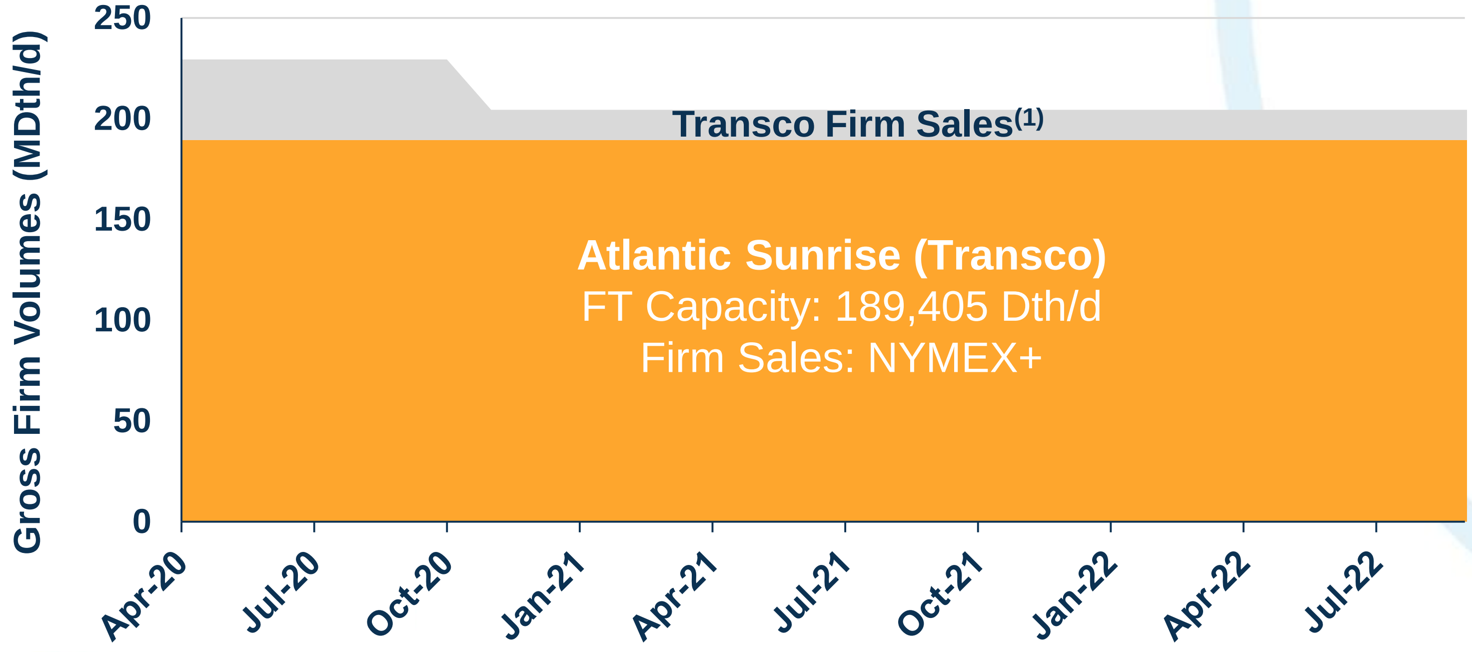
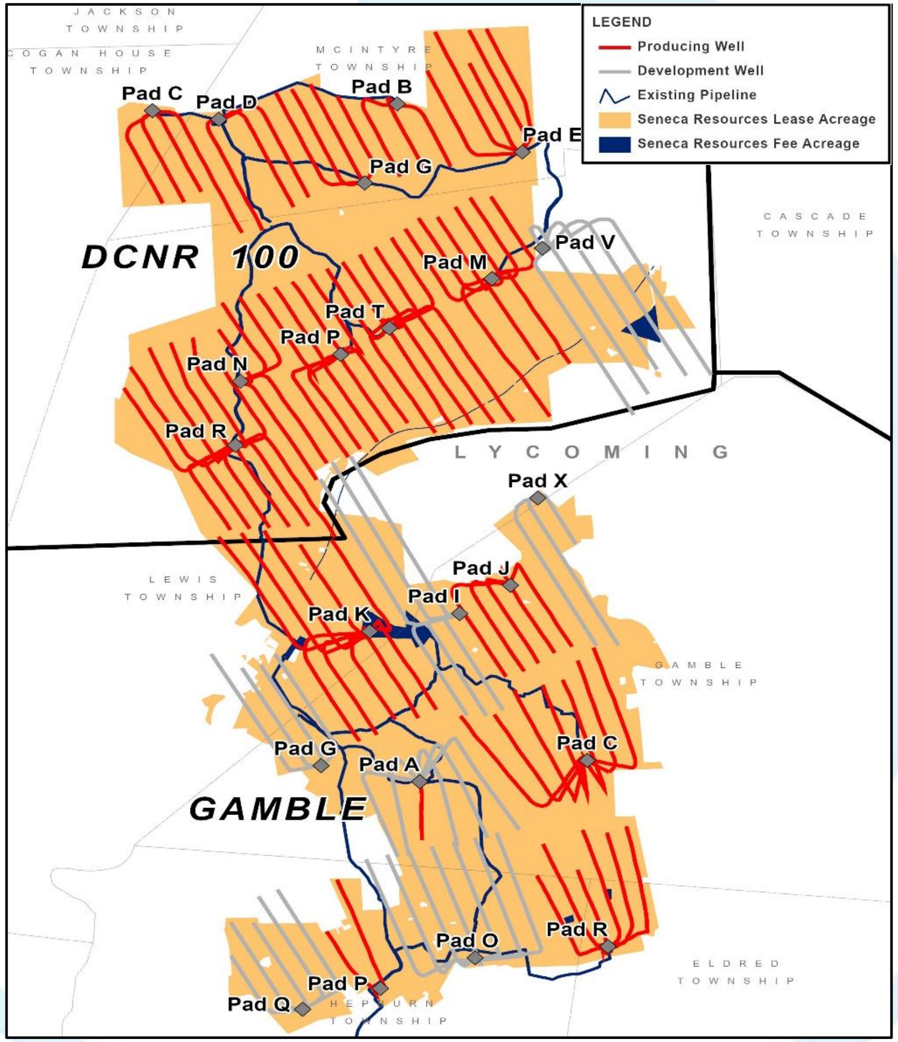
EDA Marcellus: Lycoming County Development

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

- ✓ Prolific Marcellus acreage with peer-leading well results
- ✓ 30-35 remaining Marcellus locations – breakeven (15% IRR) consolidated economics of ~$1.11
- ✓ Near-term development focused on Atlantic Sunrise capacity

EDA – Transco Firm Contracts



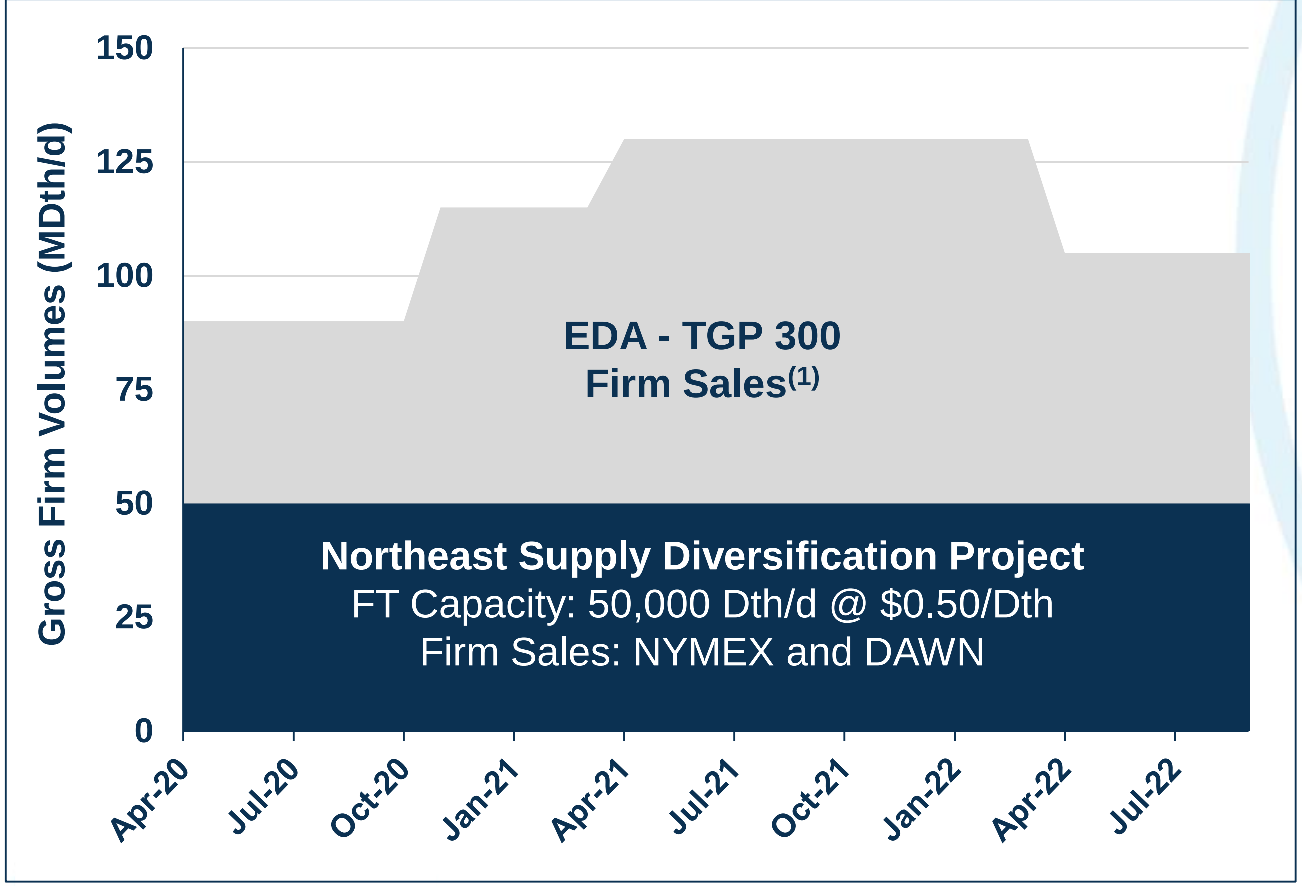


(1) Includes physical fixed price and NYMEX-based firm sales contracts that do not carry any additional transportation costs.

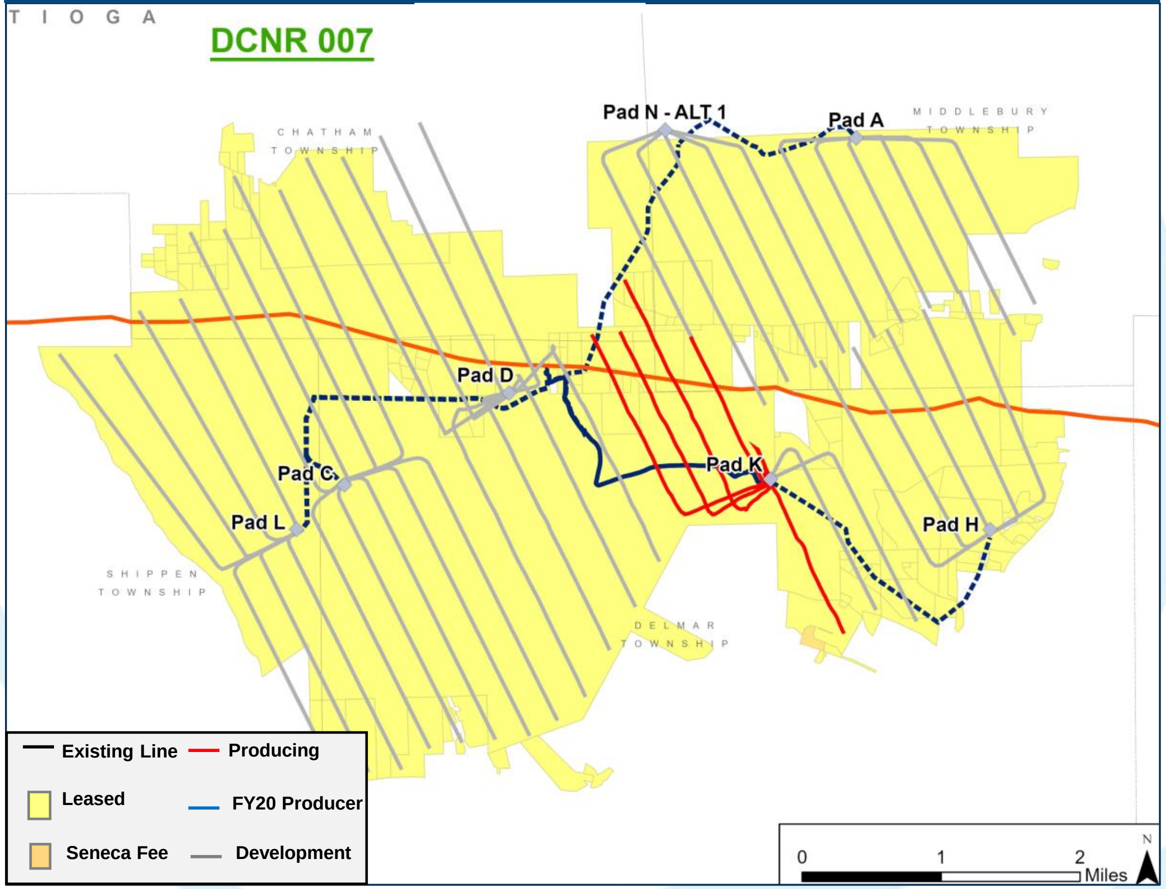
EDA Utica: Tioga County Development

Development Focused on Tract 007 Production Area, with Production Underpinned by Firm Sales

EDA – TGP 300 Firm Contracts



DCNR Tract 007



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

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EDA Utica: Tioga County Development

Tract 007 Utica Wells Brought Online in Q2 Fiscal 2019 Tracking Best Industry Results to Date

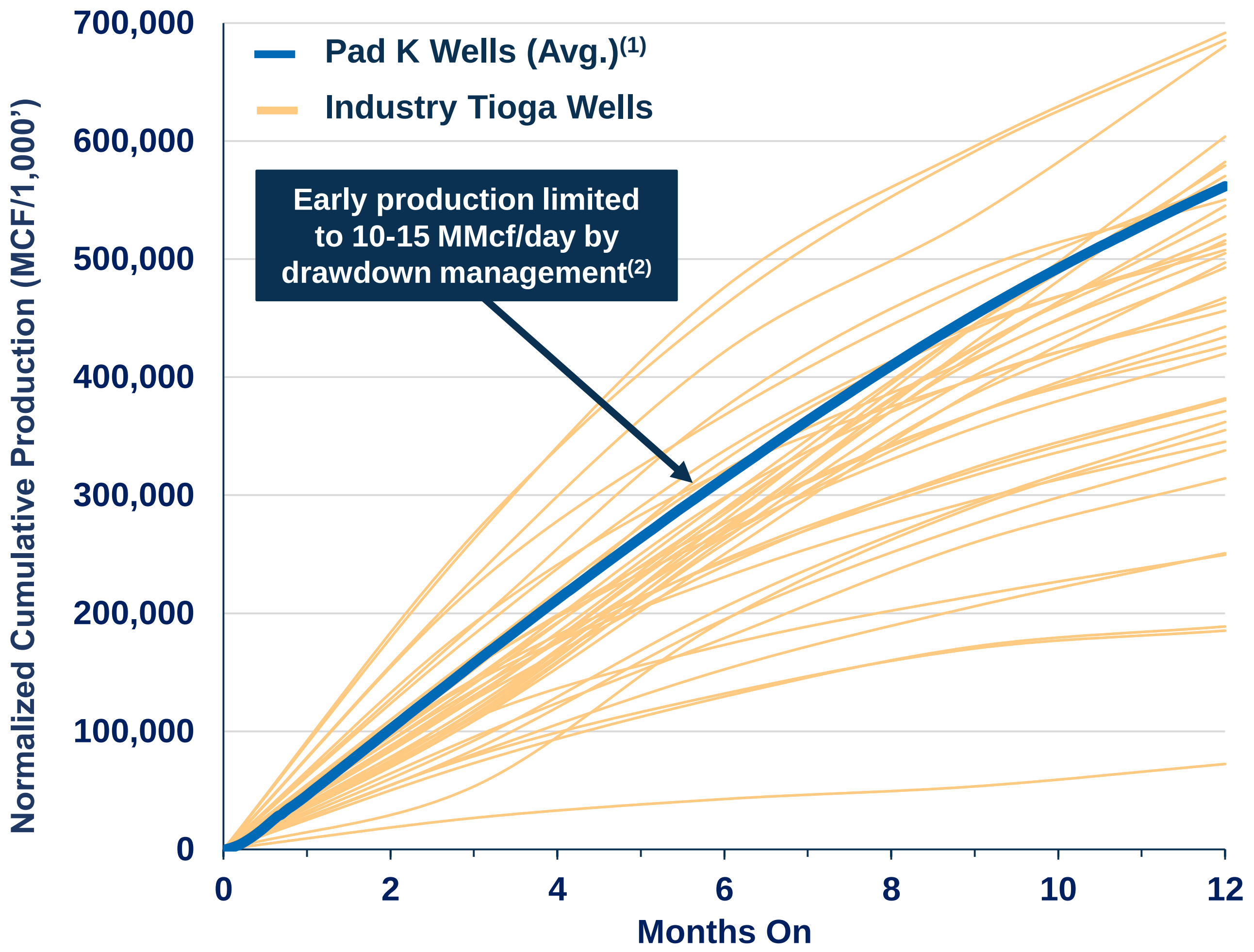
Tract 007 Utica Development Update

- ✓ Production from first multi-well pad (4 wells) brought online in February/March 2019
- ✓ Early results compare favorably with industry Tioga County wells
- ✓ 35-40 remaining locations – breakeven (15% IRR) consolidated economics at ~$1.40/Mcf

Tract 007 Pad K Early Well Results[(1)]

- ✓ **Well Count**: 4
- ✓ **Lateral Length**: 7,582'
- ✓ **IP_{30} Rate**: 13.8 MMcf/day
- ✓ **IP_{365} Rate**: 11.6 MMcf/day
- ✓ **Drawdown Management**: restricted drawdown appears to improve well performance

Tract 007 Utica Well Results vs. Industry



(1) All numbers are average of 4 Pad K wells brought online in February and March 2019.
(2) Three wells brought online in February 2019 restricted to ~15 MMCFPD, and one well brought online in late March 2019 restricted to ~10 MMCFPD.

Integrated Development – EDA Gathering Systems

Gathering Segment Supporting Seneca and Third-Party Production & Future Development

Wellsboro Gathering System

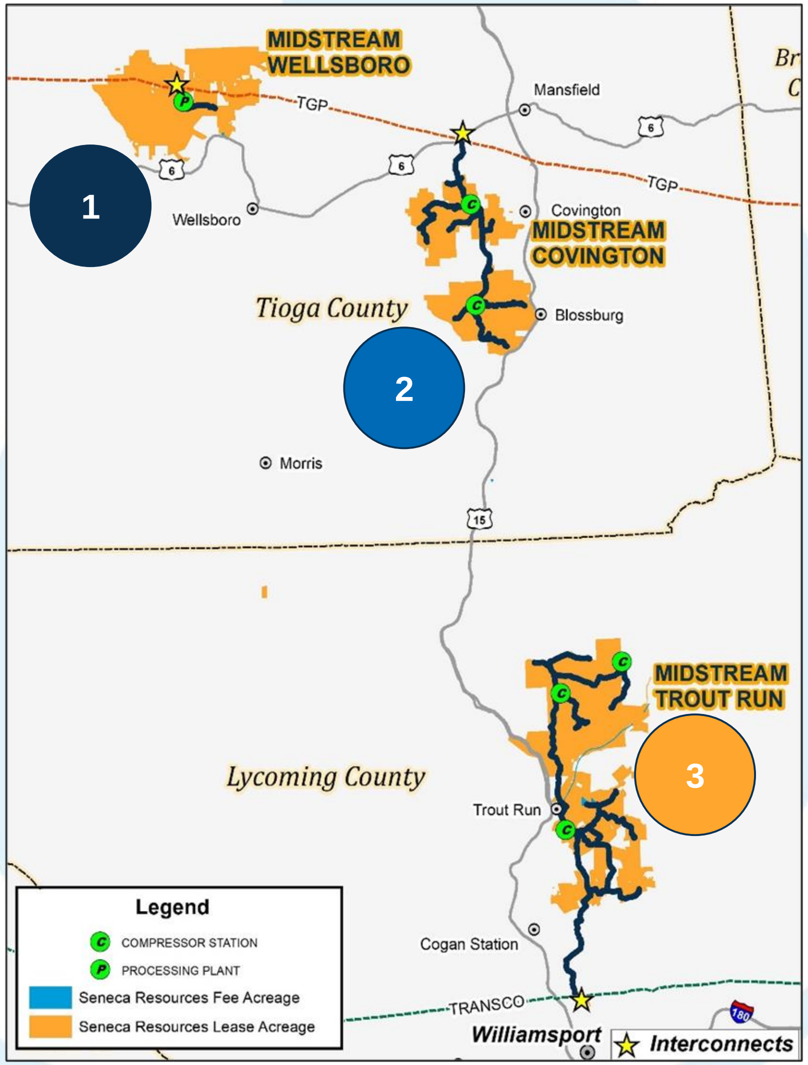
- **Total Investment (to date):** ~$22 million
- **Capacity:** up to 200,000 Dth per day (Interconnect w/ TGP 300)
- **Production Source:** Seneca Resources – Tioga Co. (DCNR Tract 007)

Covington Gathering System

- **Total Investment (to date):** ~$48 million
- **Capacity:** 220,000 Dth per day (Interconnect w/ TGP 300)
- **Production Source**: Seneca Resources – Tioga Co. (Covington & DCNR Tract 595)

Trout Run Gathering System

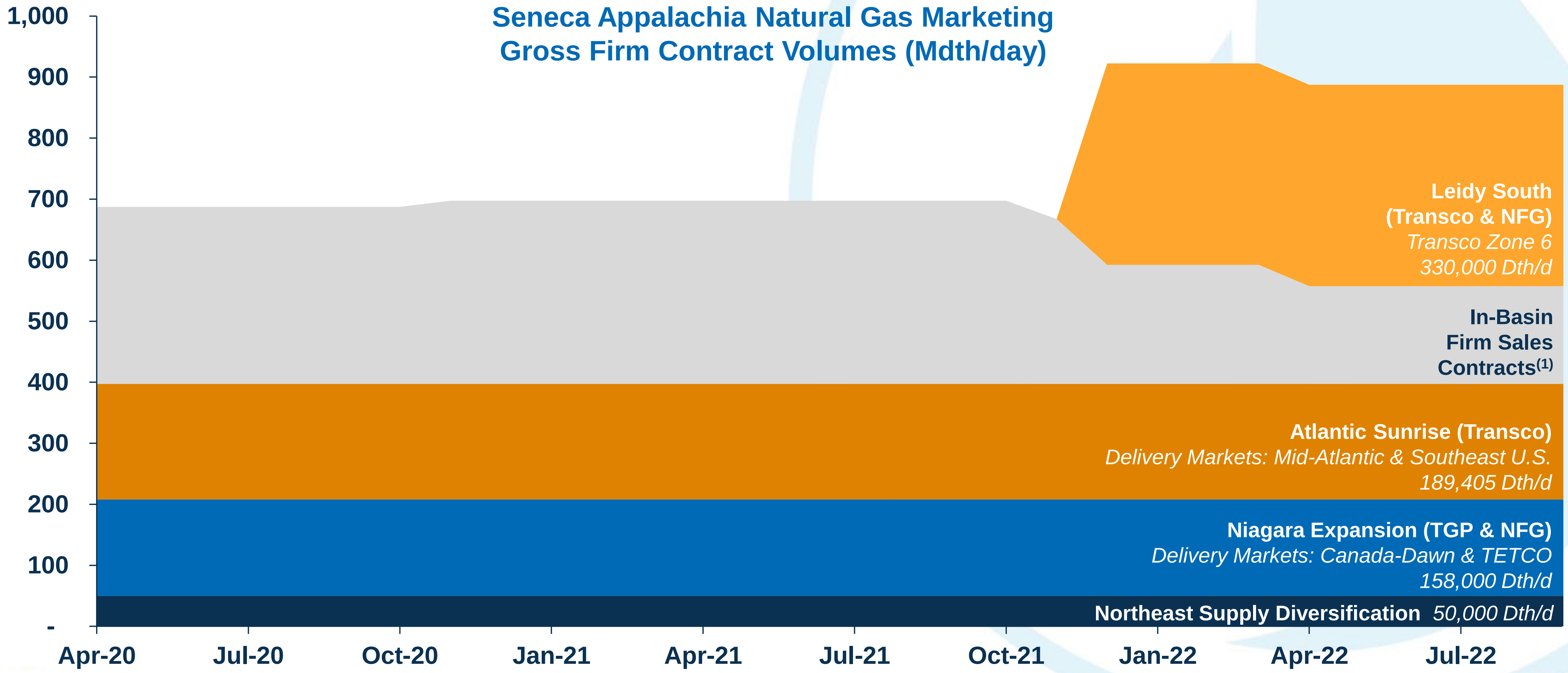
- **Total Investment (to date):** ~$239 million
- **Capacity:** 466,000 to 585,000 Dth per day (Interconnect w/ Transco)
- **Production Source:** Seneca Resources – Lycoming Co. (DCNR Tract 100 & Gamble)
- *Third-party volumes under contract and expected to come online in early fiscal 2021*



National Fuel

Long-term Contracts Supporting Appalachian Production

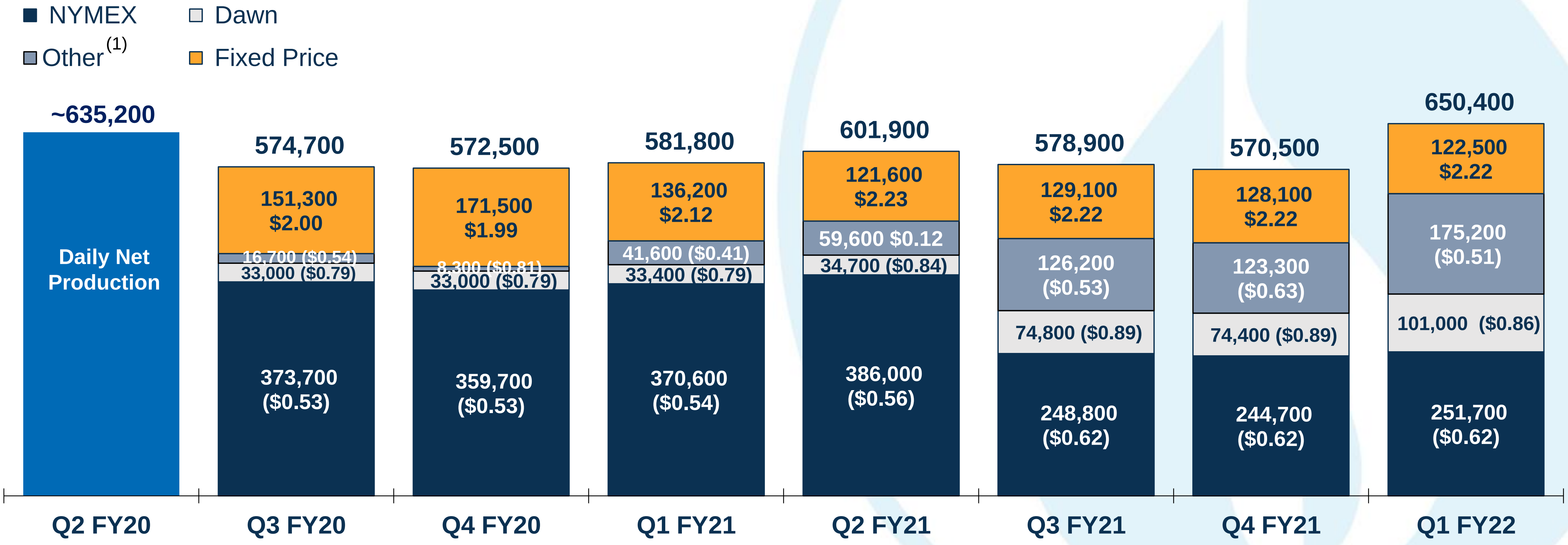
Seneca continues to layer-in firm sales contracts to lock-in drilling economics and minimize spot exposure ahead of firm transportation in-service dates



(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)



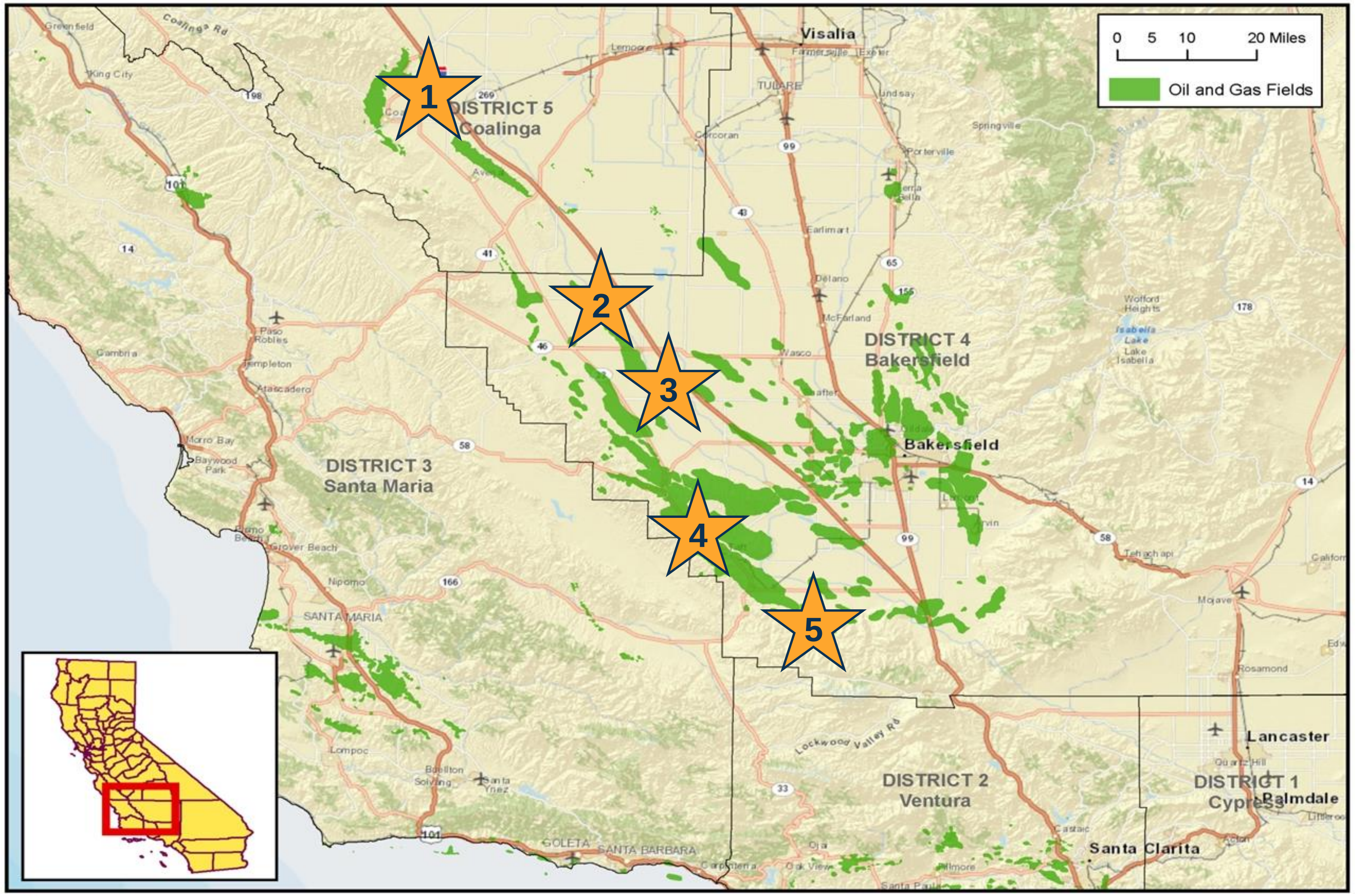
	Q2 FY20	Q3 FY20	Q4 FY20	Q1 FY21	Q2 FY21	Q3 FY21	Q4 FY21	Q1 FY22
Gross Firm Sales Volumes (Dth/d)		689,300	681,800	688,400	707,100	699,300	691,700	781,000

(1) Values shown represent the weighted average fixed price or weighted average differential relative to NYMEX (netback price) less any associated transportation costs. Transportation costs include minor variable components such as the Canadian exchange rate and fuel components. With respect to "Other", the weighted average differential relative to NYMEX (netback price) includes net contracted firm sales at various indices, which are to subject to fluctuations in the market, such as seasonal demand swings, and is calculated using forward basis at various associated locations as specified by the underlying contract.

National Fuel

California Oil

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

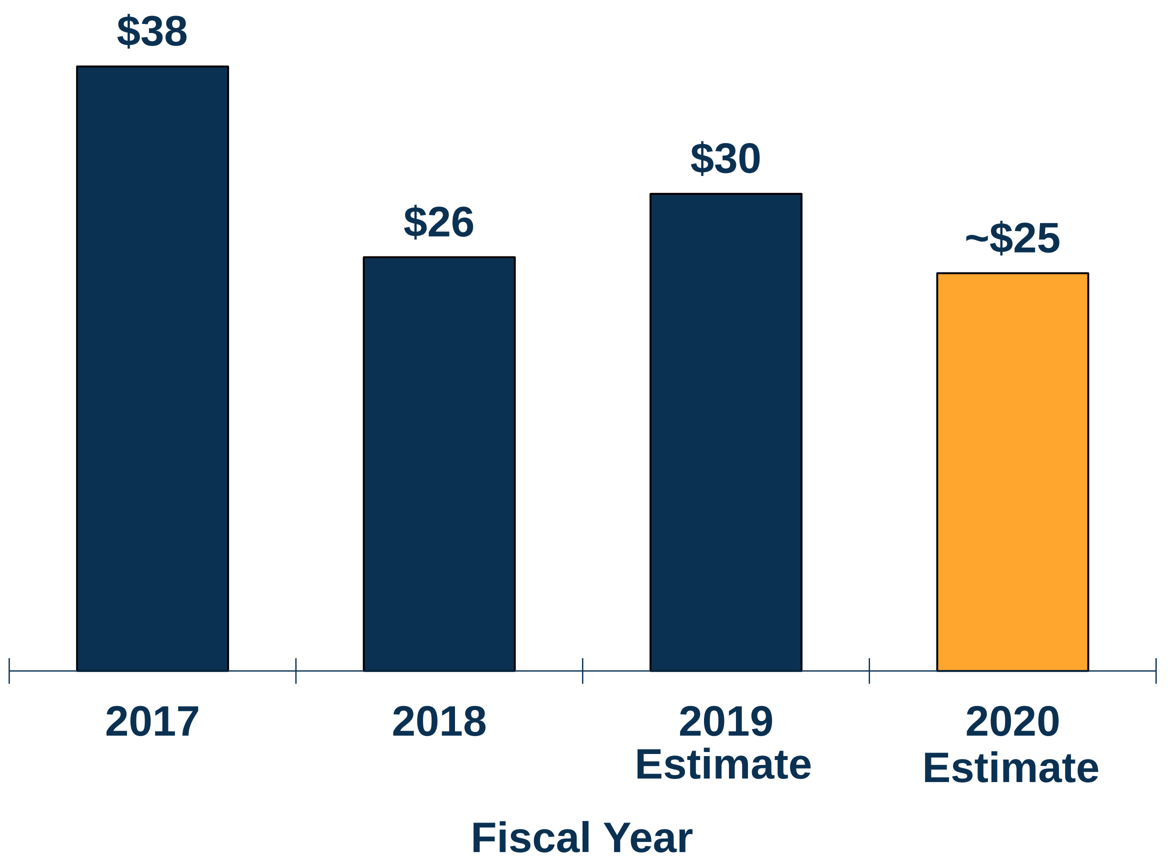


	Location	Formation	Production Method	Avg. Daily Production *(net Boe/d)*(1)
1	East Coalinga/ Other	Temblor	Primary	532
2	North Lost Hills	Tulare & Etchegoin	Primary/ Steam flood	866
3	South Lost Hills	Monterey Shale	Primary	1,198
4	North Midway Sunset	Tulare & Potter	Steam flood	2,800
5	South Midway Sunset	Antelope	Steam flood	2,131
	TOTAL WEST DIVISION AVG. NET PRODUCTION(1)			7,527 Boe/d

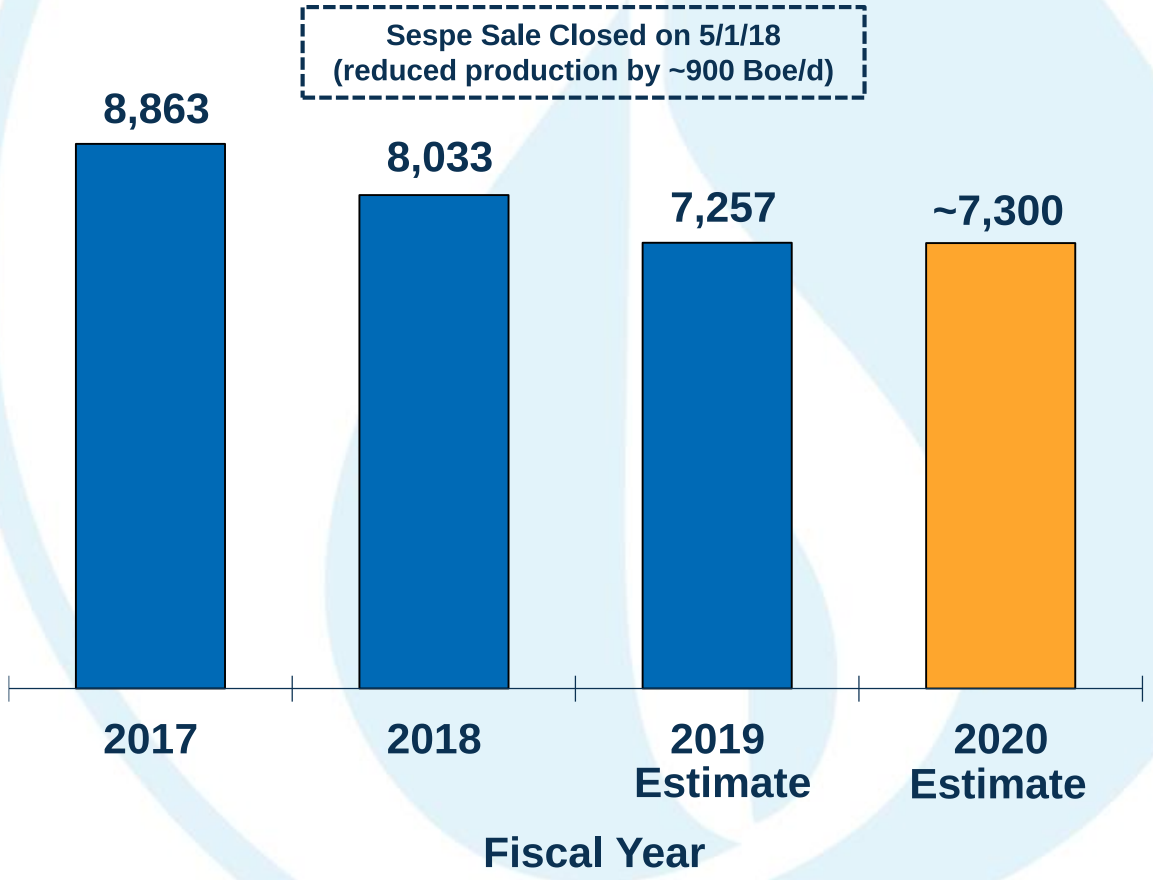
(1) Average daily net production (oil and natural gas) for West division for quarter ended March 31, 2020.

California Capital Expenditures vs. Production

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



West Division Average Net Daily Production (Boe)

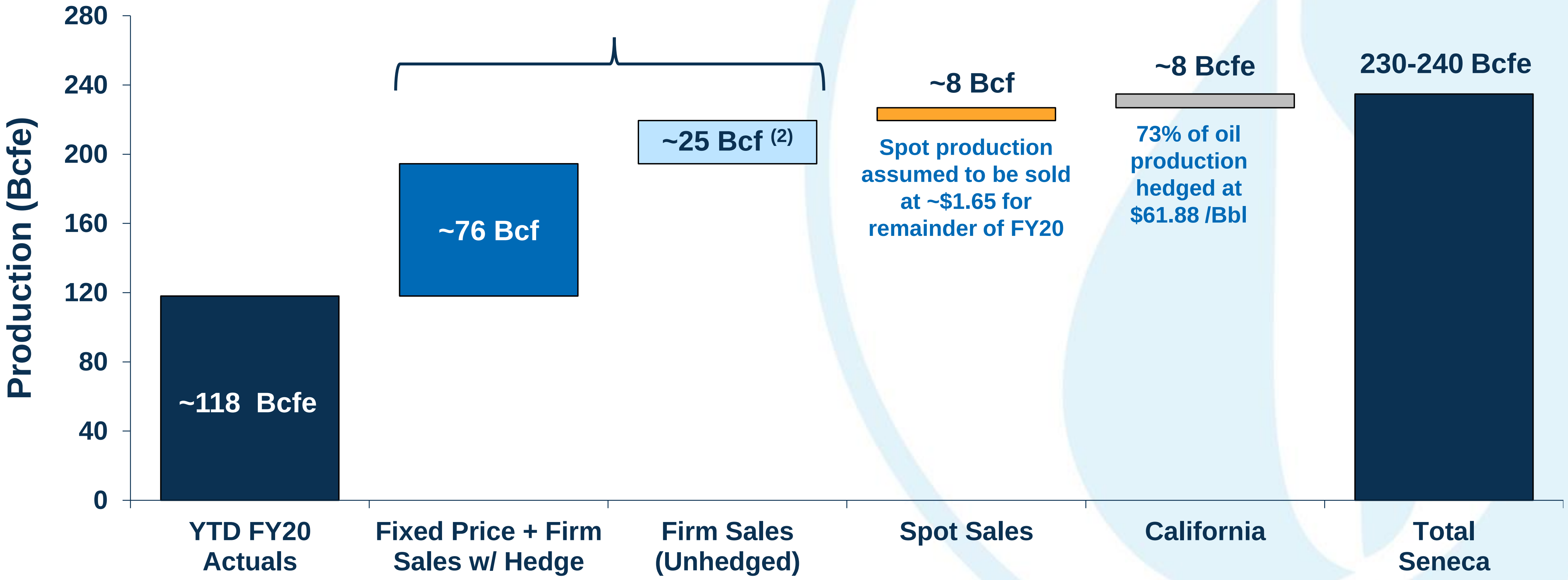


(1) Seneca West Division capital expenditures includes Seneca corporate and eliminations.

Fiscal 2020 Production and Price Certainty

101 Bcf of Appalachian Production Protected by Firm Sales

- 76 Bcf locked-in realizing net ~$2.16/Mcf (1)
- 25 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.

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Hedge Positions and Prices

Natural Gas - *MMDth, $/MMBtu*

Fiscal Year	Total	Swaps	Fixed Price Physical[3]	2-Way Collars	Swaps Price	Fixed Price Physical Price	2-Way Collars Price
Fiscal 2020	78.9 MMDth ~72% Hedged[1]	49.3	29.6	-	$2.69	$2.18	-
Fiscal 2021	191.2 MMDth	118.5	46.8	25.9	$2.61	$2.22	$2.28 / $2.77[2]
Fiscal 2022	105.5 MMDth	62.6	40.6	2.4	$2.52	$2.23	$2.28 / $2.77[2]

■ Swaps ■ Fixed Price Physical[3] ■ 2-Way Collars

Crude Oil - *MBbl, $/Bbl*

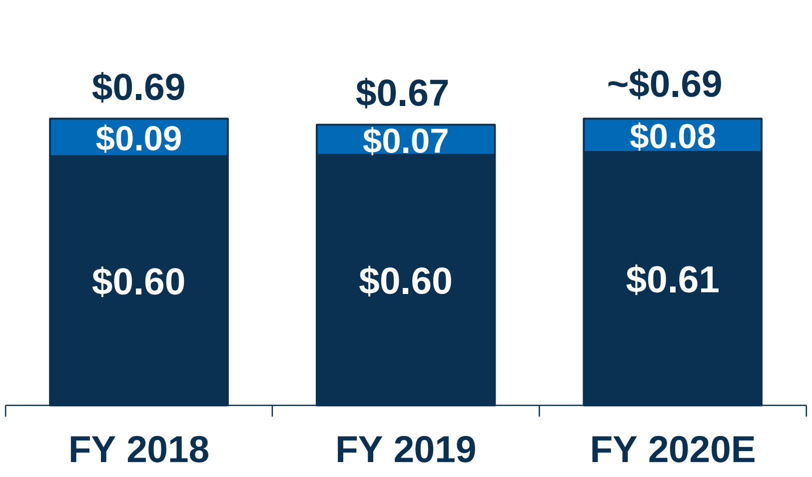
Fiscal Year	Total	Brent Swaps	NYMEX Swaps	Brent Swaps Price	NYMEX Swaps Price
Fiscal 2020	852 MBbl ~73% Hedged[1]	690	162	$64.55	$50.52
Fiscal 2021	852 MBbl	696	156	$64.29	$51.00
Fiscal 2022	456 MBbl	300	156	$60.07	$51.00

■ Brent Swaps ■ NYMEX Swaps

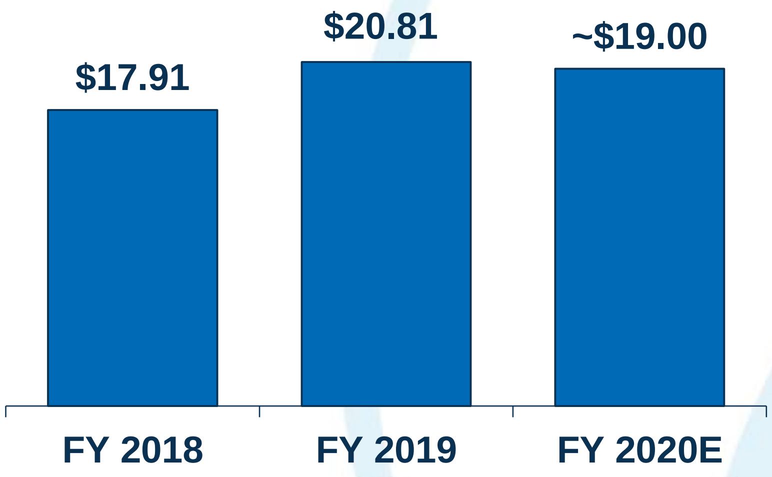
(1) Reflects percentage of remaining projected production for FY20 hedged at the midpoint of the production guidance range.
(2) Average weighted floor and ceiling prices.
(3) Fixed price physical sales exclude joint development partner's share of fixed price contract WDA volumes as specified under the joint development agreement. Swaps and 2-way collar prices do not include cost of transport.

Seneca Operating Costs

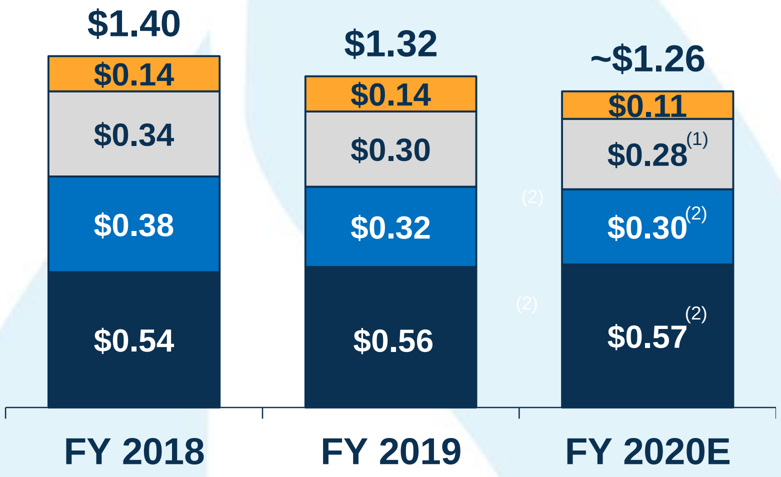
Appalachia LOE & Gathering
$/Mcfe



California LOE
$/Boe

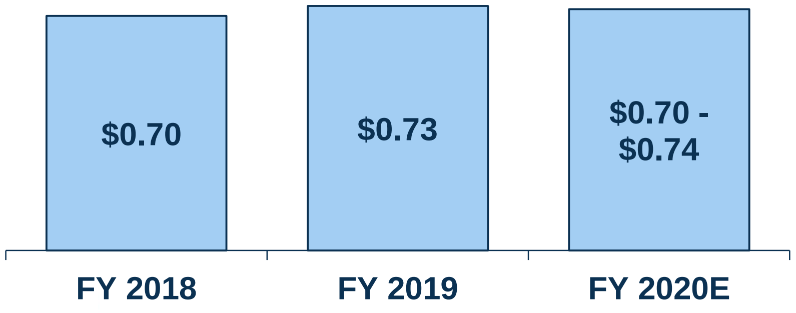


Total Seneca Cash OpEx
$/Mcfe



■ 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 of $0.27 to $0.30 for fiscal 2020.
(2) The total of the two LOE components represents the midpoint of the LOE guidance range of $0.85 to $0.89 for fiscal 2020.

Pipeline and Storage Overview

National Fuel Gas Supply Corporation ~ Empire Pipeline, Inc.

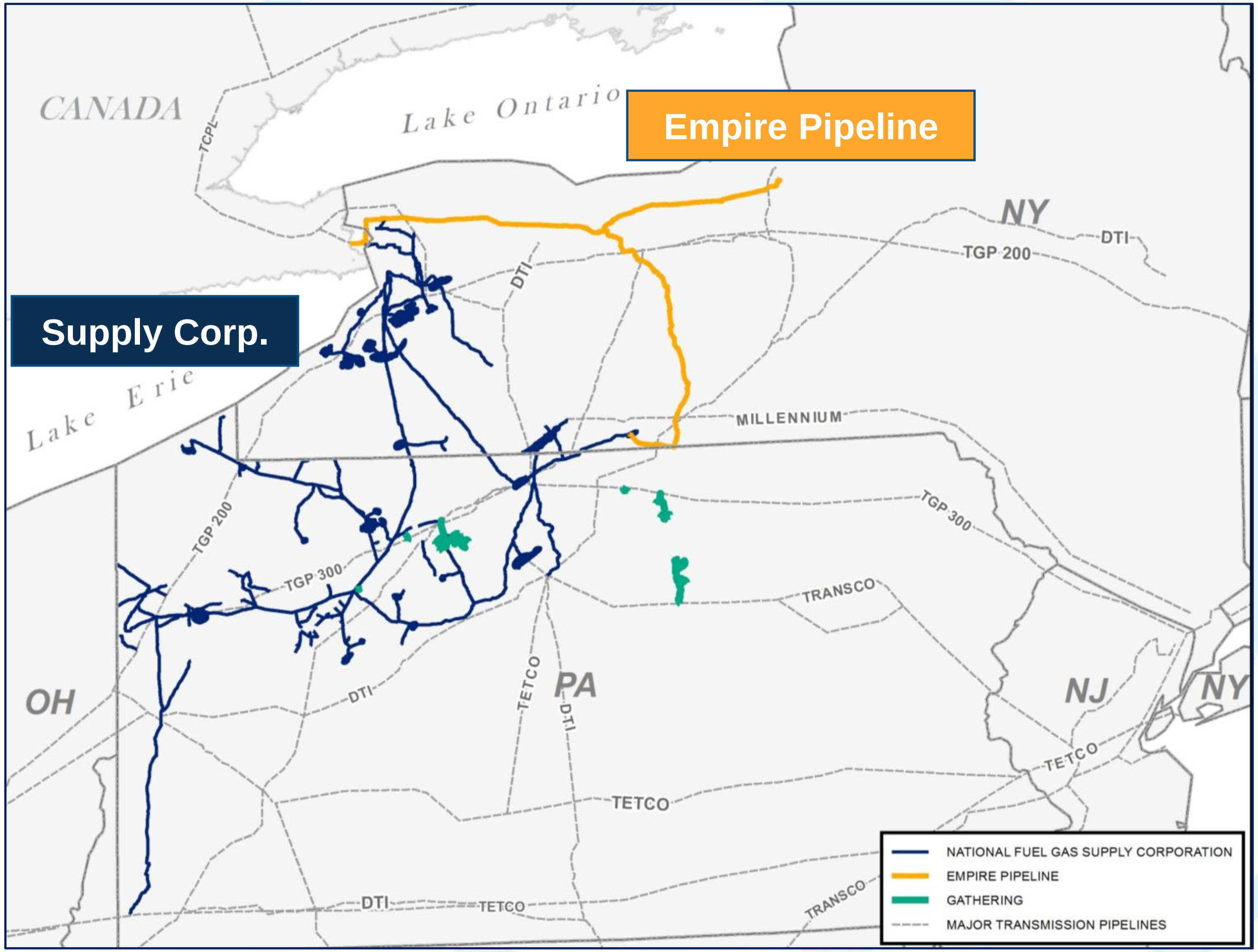
Pipeline & Storage Segment Overview

National Fuel Gas Supply Corporation

- ✓ **Contracted Capacity[(1)]:**
  - Firm Transportation: 3,078 MDth per day
  - Firm Storage: 70,693 Mdth (fully subscribed)
- ✓ **Rate Base[(2)]:** ~$944 million
- ✓ **FERC Rate Proceeding Status:**
  - Settlement reached, with interim rates in effect 2/1/20
  - Settlement agreement filed with FERC on 3/13/20 (awaiting Commission approval)

Empire Pipeline, Inc.

- ✓ **Contracted Capacity[(1)]:**
  - Firm Transportation: 853 MDth per day
  - Firm Storage: 3,753 Mdth (fully subscribed)
- ✓ **Rate Base[(2)]:** ~$247 million
- ✓ **FERC Rate Proceeding Status:**
  - Rate case settlement approved May 2019
  - New transportation rates went into effect on 1/1/19

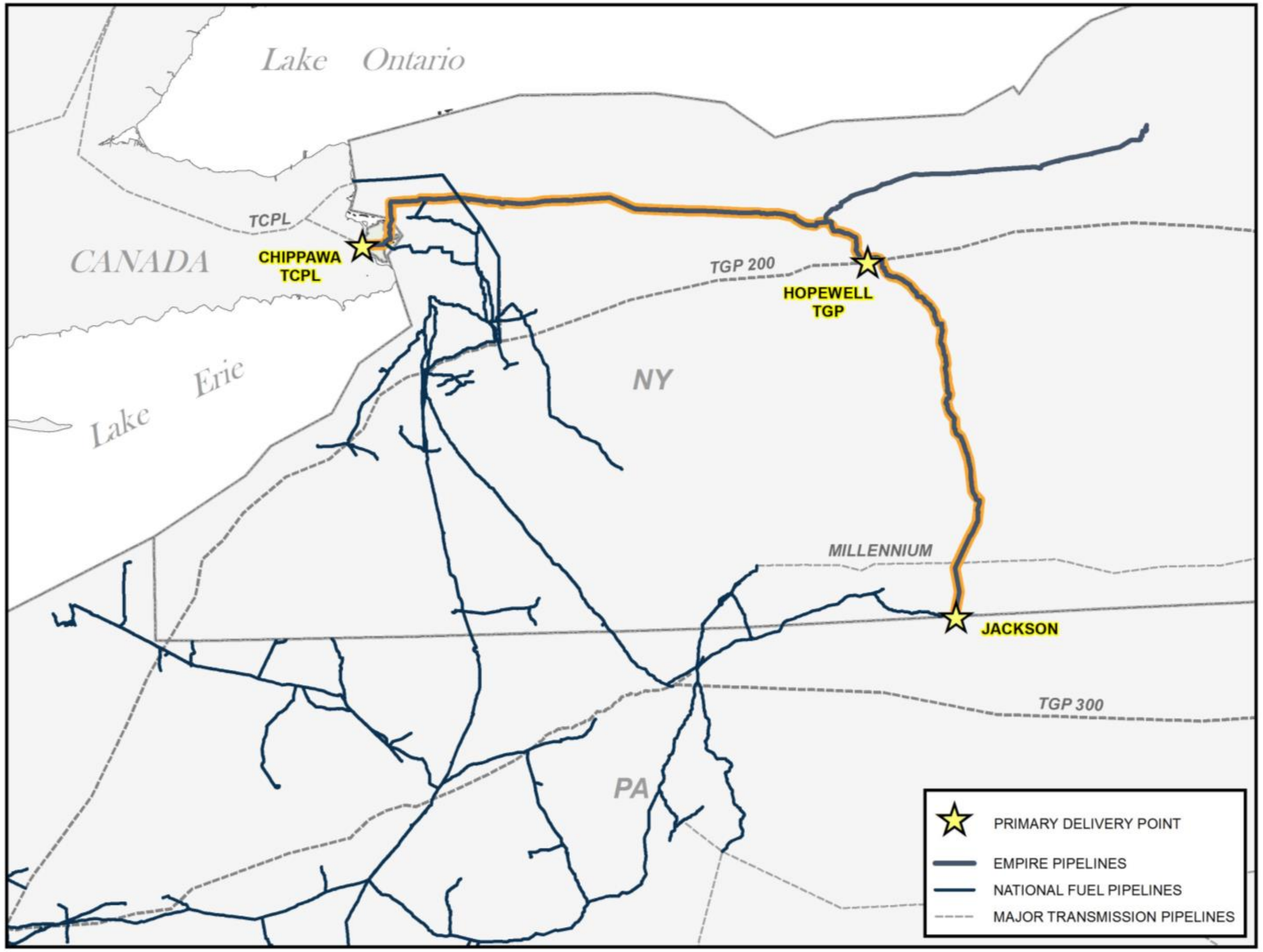


(1) As of September 30, 2019 as disclosed in the Company's fiscal 2019 Form 10-K.
(2) As of December 31, 2019 calculated from National Fuel Gas Supply Corporation's and Empire Pipeline, Inc.'s 2019 FERC Form-2 reports, respectively.

Empire North Project

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

- **Target in-service:** fourth quarter fiscal 2020 (construction underway)
- **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)
- **Major facilities:**
  - ✓ 2 new compressor stations in NY (1) & Pa. (1)
  - ✓ No new pipeline construction
- **Regulatory process:**
  - ✓ FERC Certificate issued 3/7/19
  - ✓ FERC Notice to Proceed issued 5/2/19



FM100 Project - Consolidated Benefit for NFG

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

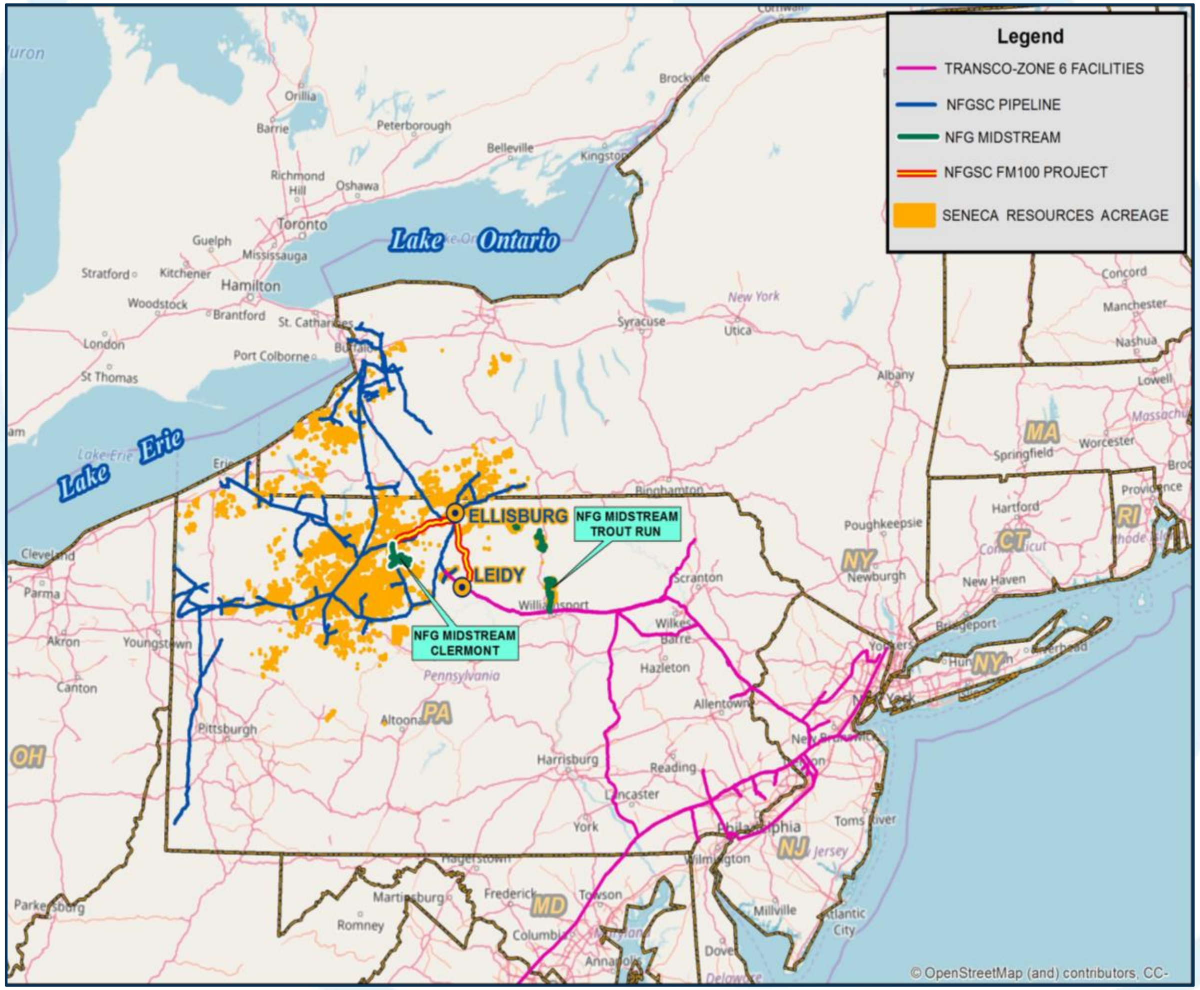
Seneca

- ✓ **New Transco capacity (Leidy South):** 330,000 Dth/day
- ✓ **Rate(1) :** 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**

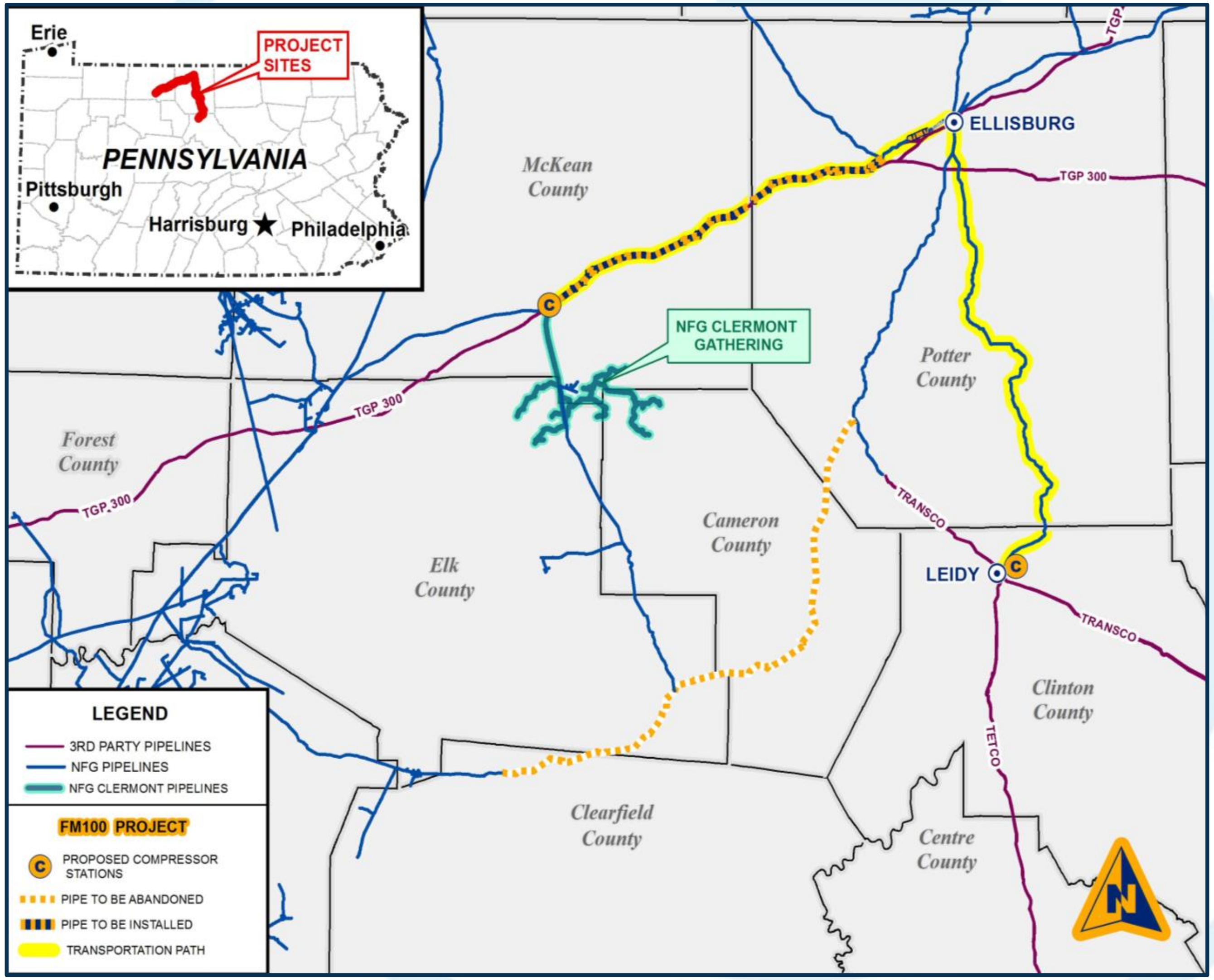
330,000 Dth/d of new transportation capacity from WDA and EDA acreage positions to premium markets



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

FM100 Project – Significant Investment by Supply Corp.

- **Estimated capital cost:** $279 million
  - Expansion facilities: ~$159 million
  - Modernization facilities: ~$120 million
- **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:**
  - FERC certificate application submitted 7/18/19
  - FERC environmental assessment issued 2/7/20



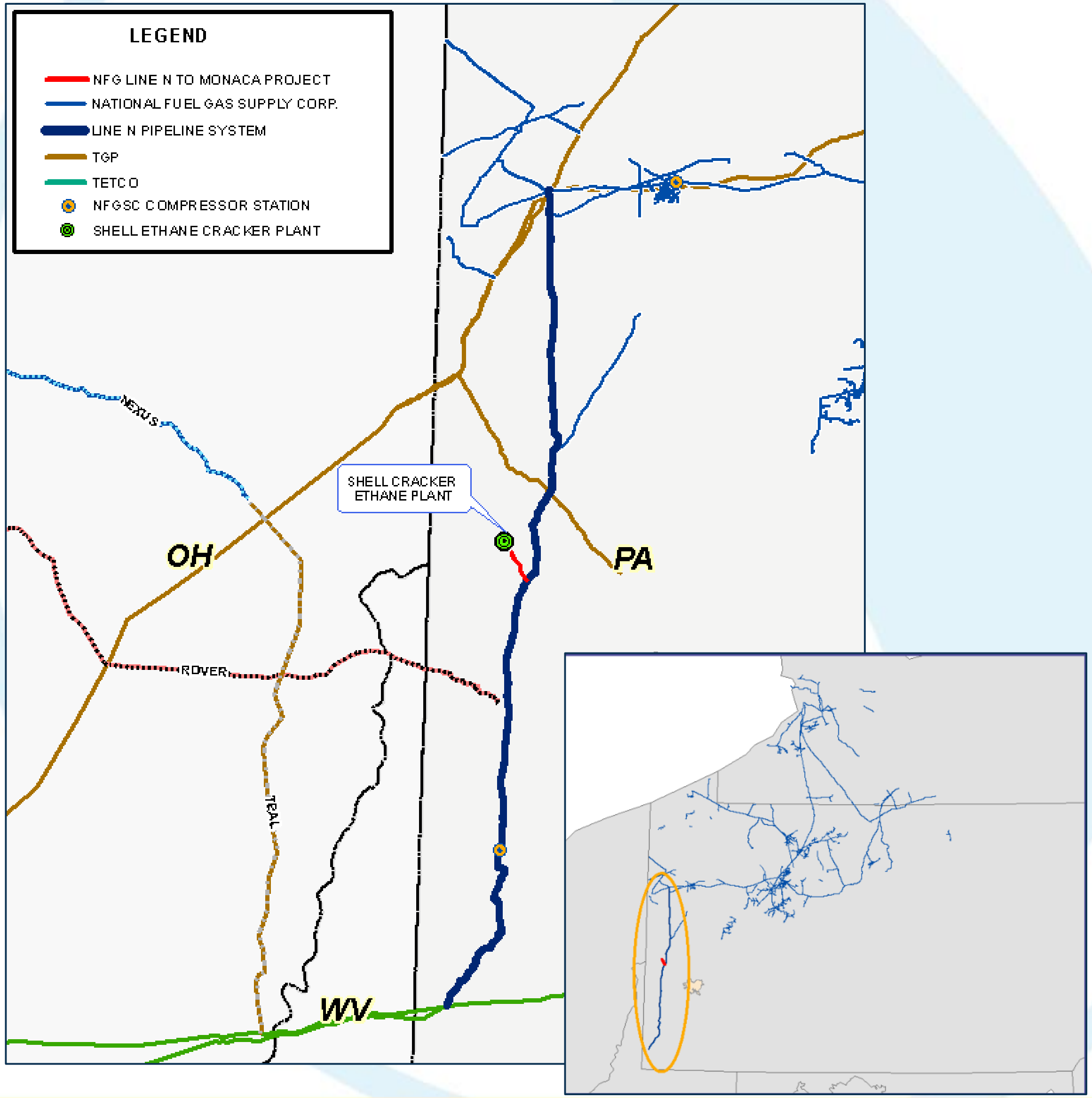
Continued Expansion of the NFG Supply System

Line N to Monaca Project

- **Project:** Firm transportation service to a new ethane cracker facility being built by Shell Chemical Appalachia, LLC
- **In-service date:** November 1, 2019
- **Capital cost:** ~$24.5 million
- **Contracted capacity:** 133,000 Dth/day

Additional Line N Expansion Potential (Supply OS 221)

- **Project:** New firm transportation service for on-system demand
- **Open season capacity:** Awarded 165,000 Dth/day to foundation shipper. Precedent agreement in negotiations.



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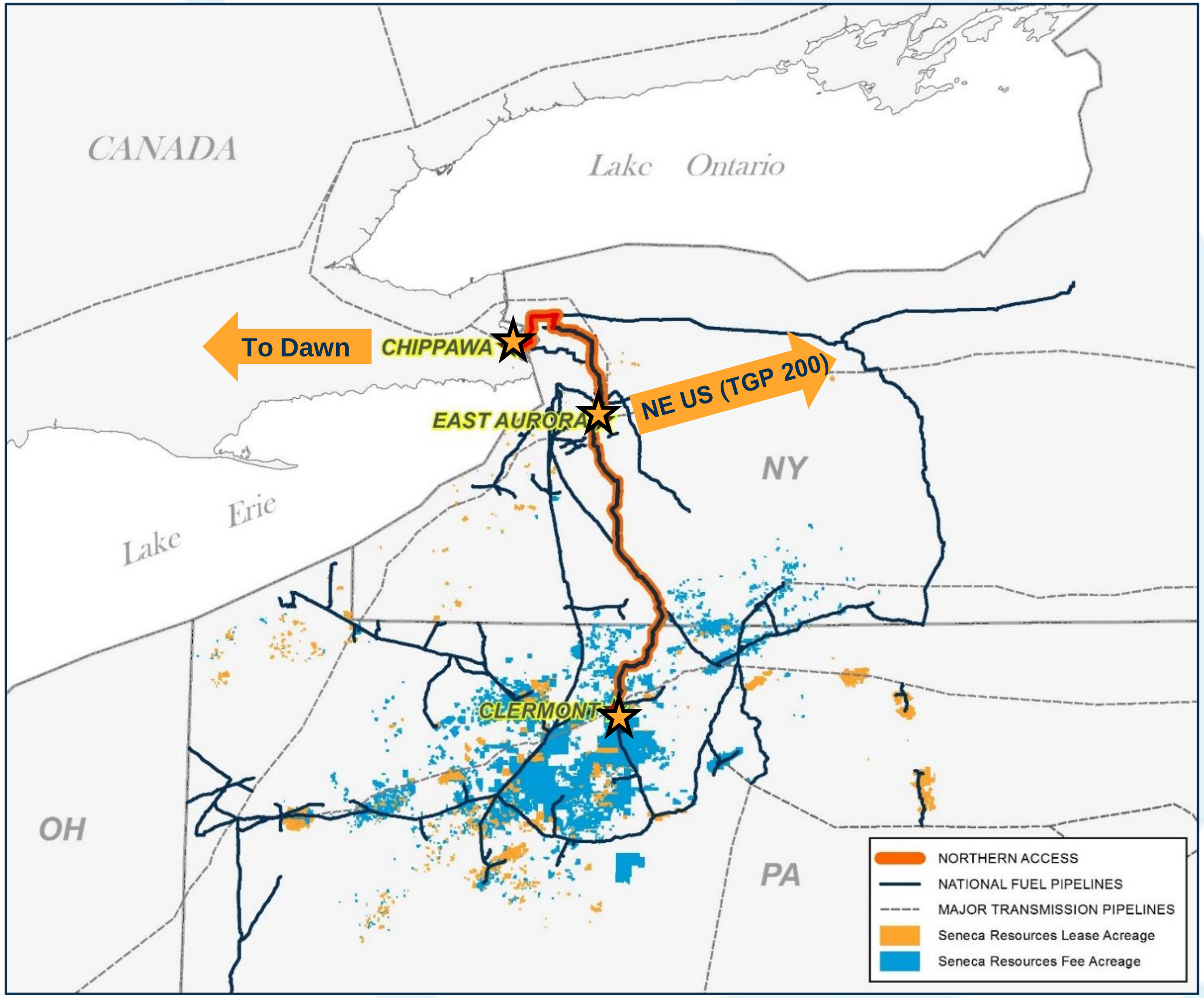
Northern Access Project

Delivery points:

- ✓ 350,000 Dth/d to Chippawa (TCPL interconnect)
- ✓ 140,000 Dth/d to East Aurora (TGP 200 line)

Regulatory/legal status:

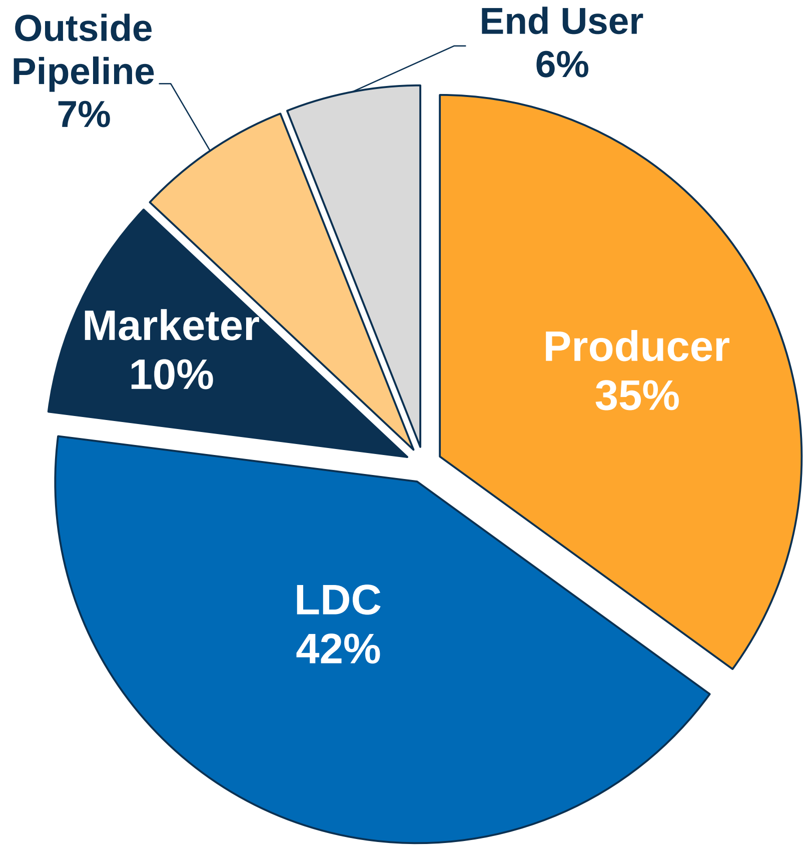
- ✓ Feb. 2017 – FERC 7(c) certificate issued
- ✓ Aug. 2018 – FERC issued Order finding that NY DEC waived water quality certification (WQC)
- ✓ Feb. 2019 – U.S. Second Circuit Court of Appeals vacated and remanded NY DEC denial of WQC
- ✓ April 2019 – FERC denied rehearing of WQC waiver order (upholding waiver finding)
- ✓ ***Supply and Empire currently working to finalize remaining federal authorizations***



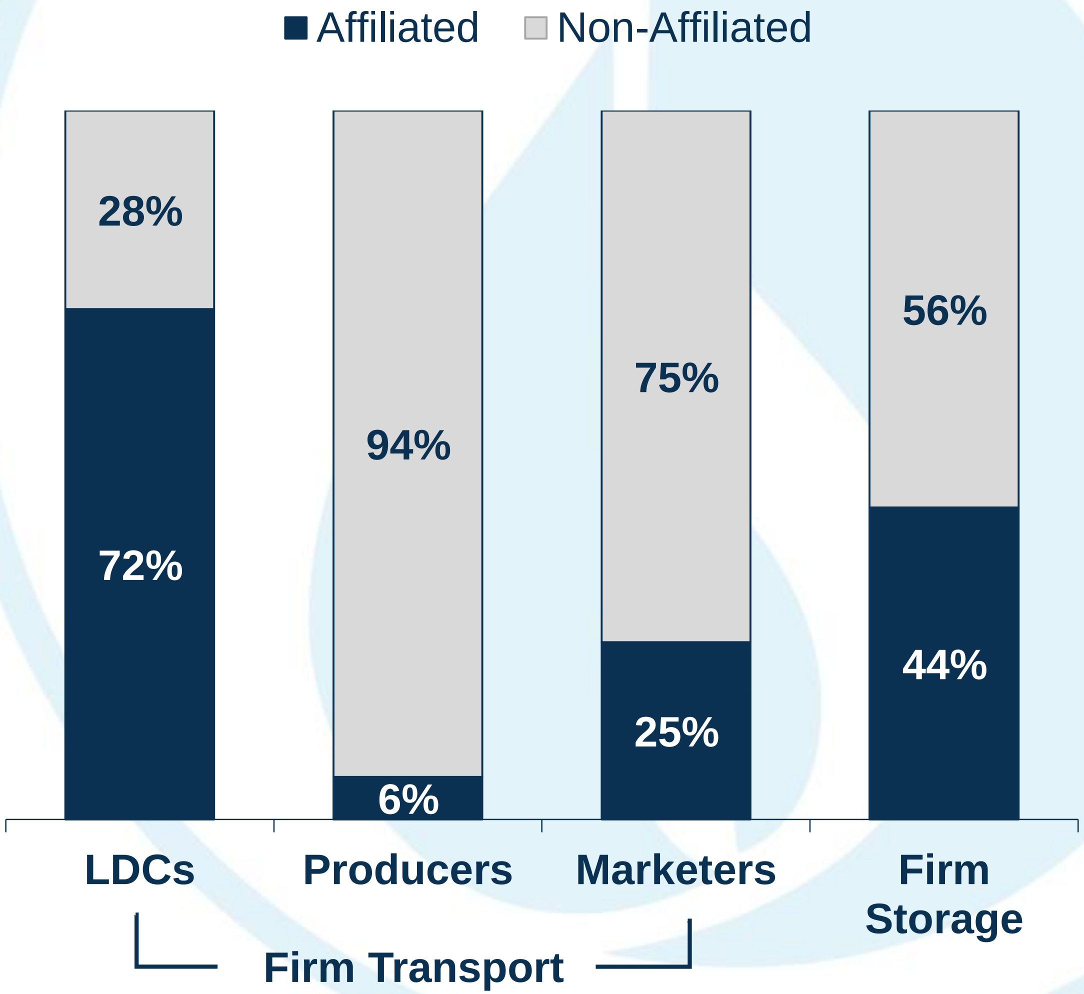
Pipeline & Storage Customer Mix

Customer Transportation by Shipper Type(1)

3.9 MMDth/d



Affiliated Customer Mix (Contracted Capacity)



(1) Contracted as of 10/31/2019.

Utility Overview

National Fuel Gas Distribution Corporation

New York & Pennsylvania Service Territories

New York

Total Customers[1]: 531,400

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)
- System Modernization Tracker

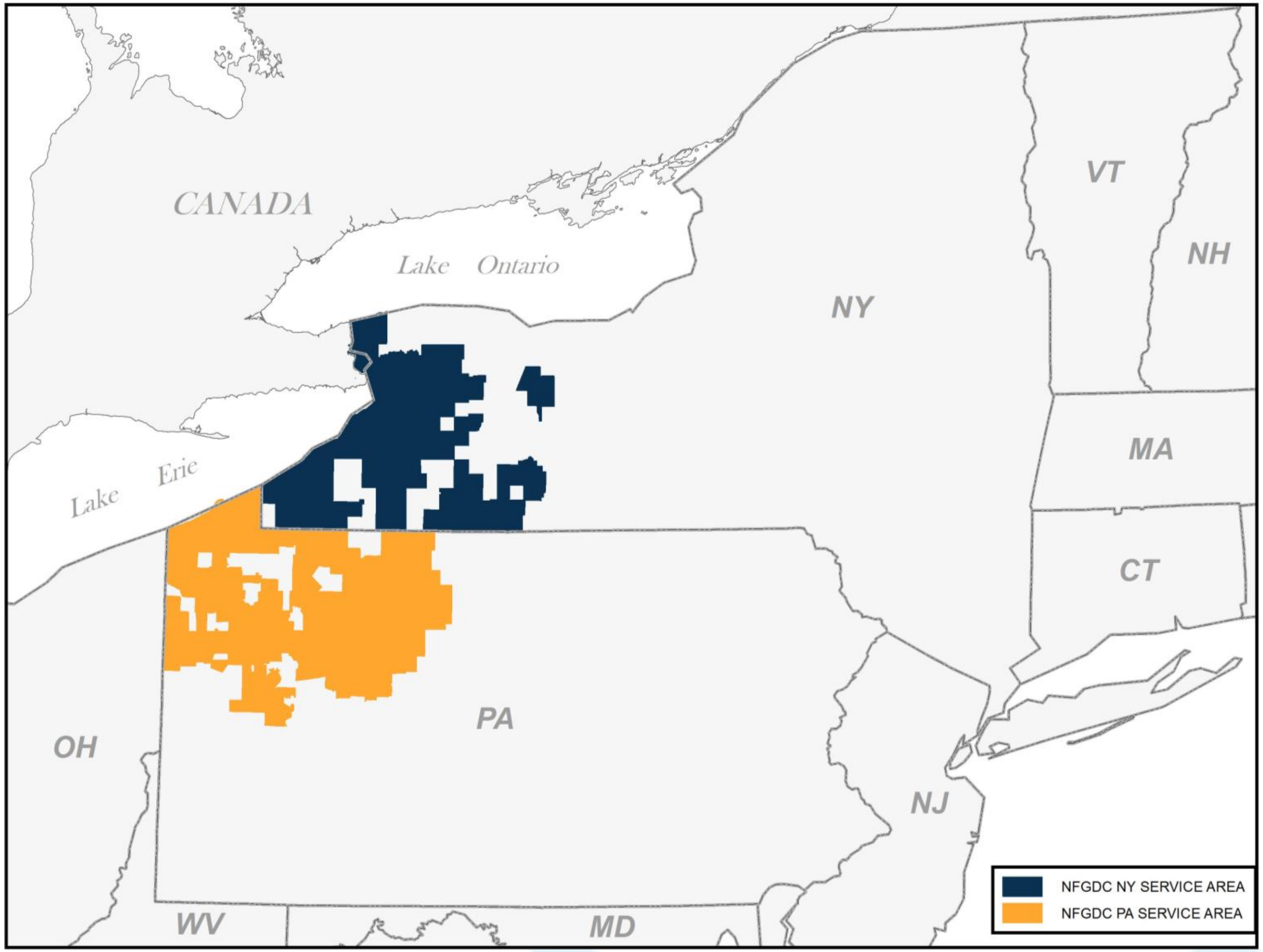
Pennsylvania

Total Customers[1]: 212,000

ROE: Black Box Settlement (2007)

Rate Mechanisms:

- Low Income Rates
- Merchant Function Charge



(1) As of September 30, 2019.

New York Rate Case Outcome

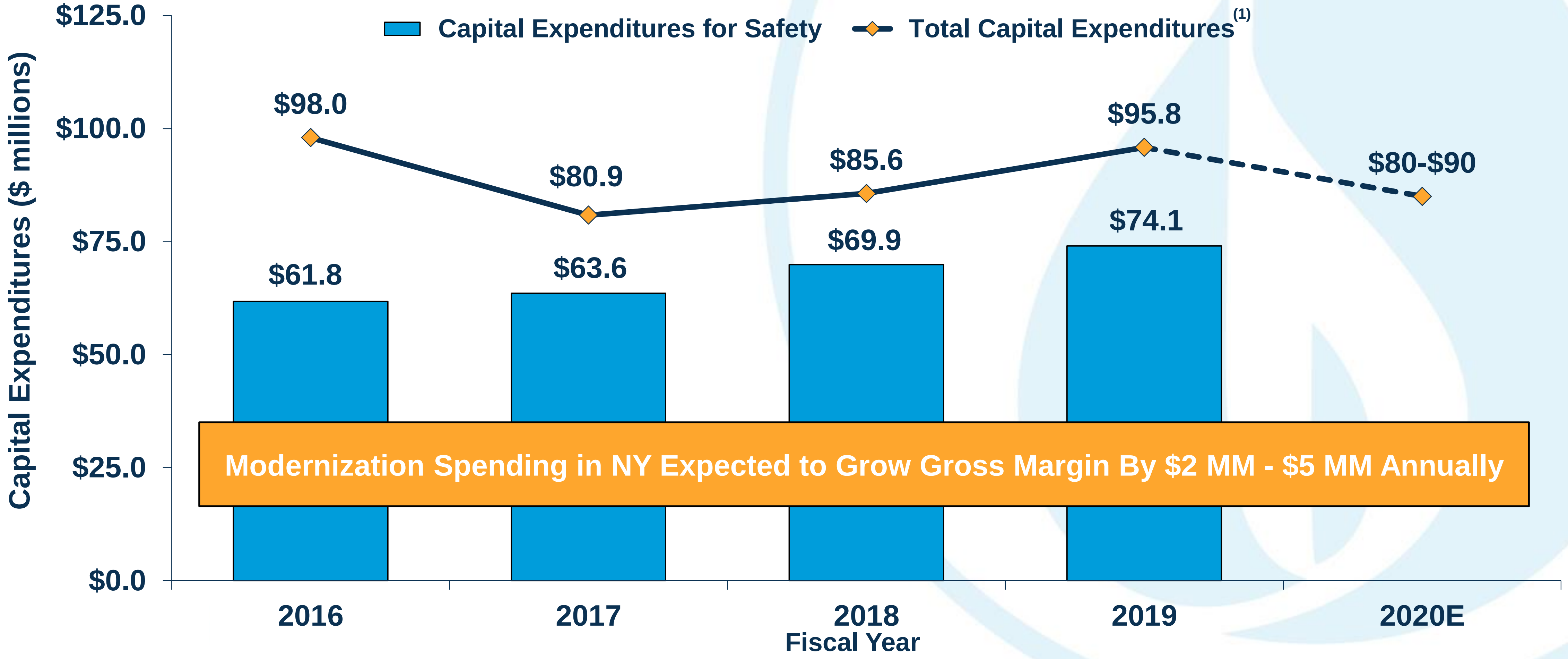
On April 20, 2017, the New York Public Service Commission issued a Rate Order relating to NFG Distribution's rate case (No. 16-G-0257) filed in April 2016.

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)
  - System modernization tracker for Leak Prone Pipe (LPP)
  - Earnings sharing started 4/1/18 (50/50 sharing starts at ROE in excess of 9.2%)

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

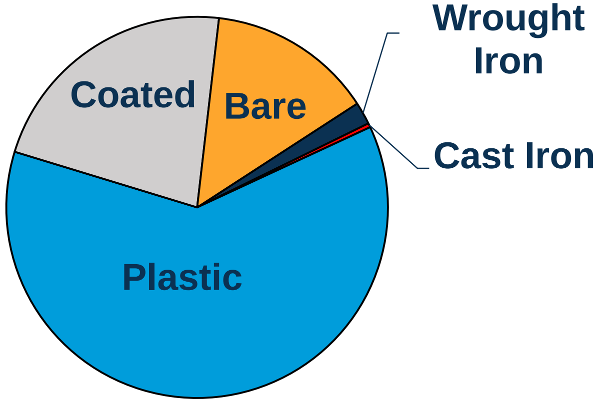


(1) A reconciliation to Capital Expenditures as presented on the Consolidated Statement of Cash Flows is included at the end of this presentation.

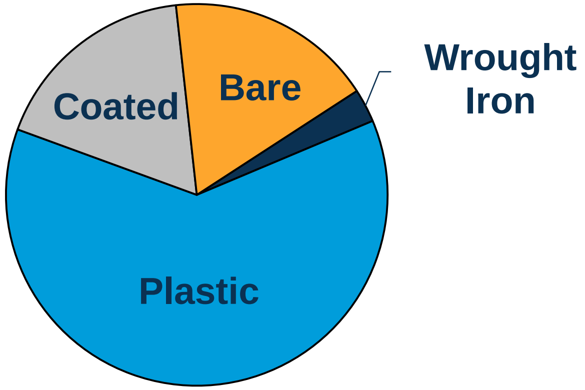
Accelerating Pipeline Replacement & Modernization

Utility Mains by Material(1)

NY
9,738 miles

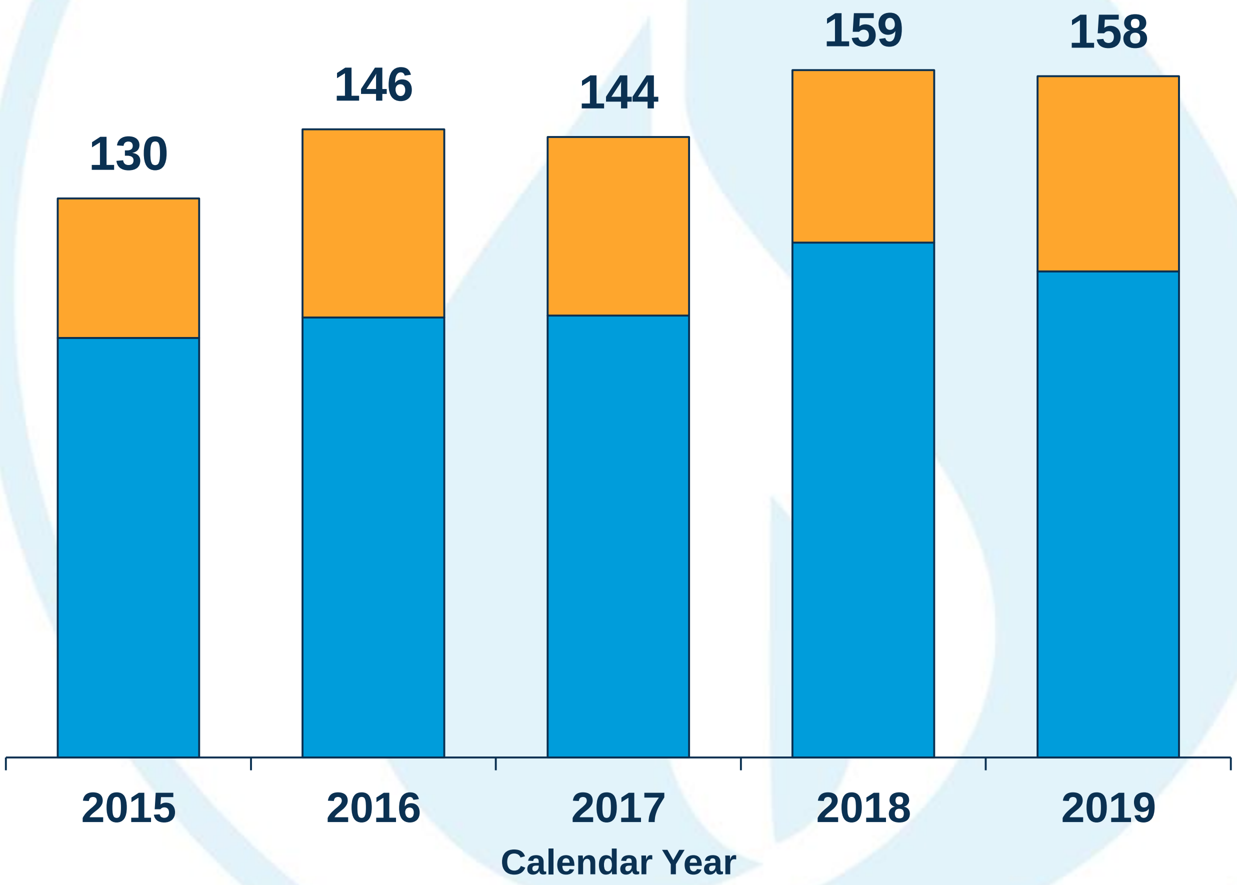


PA*
4,843 miles



*** No Cast Iron Mains in Pa.***

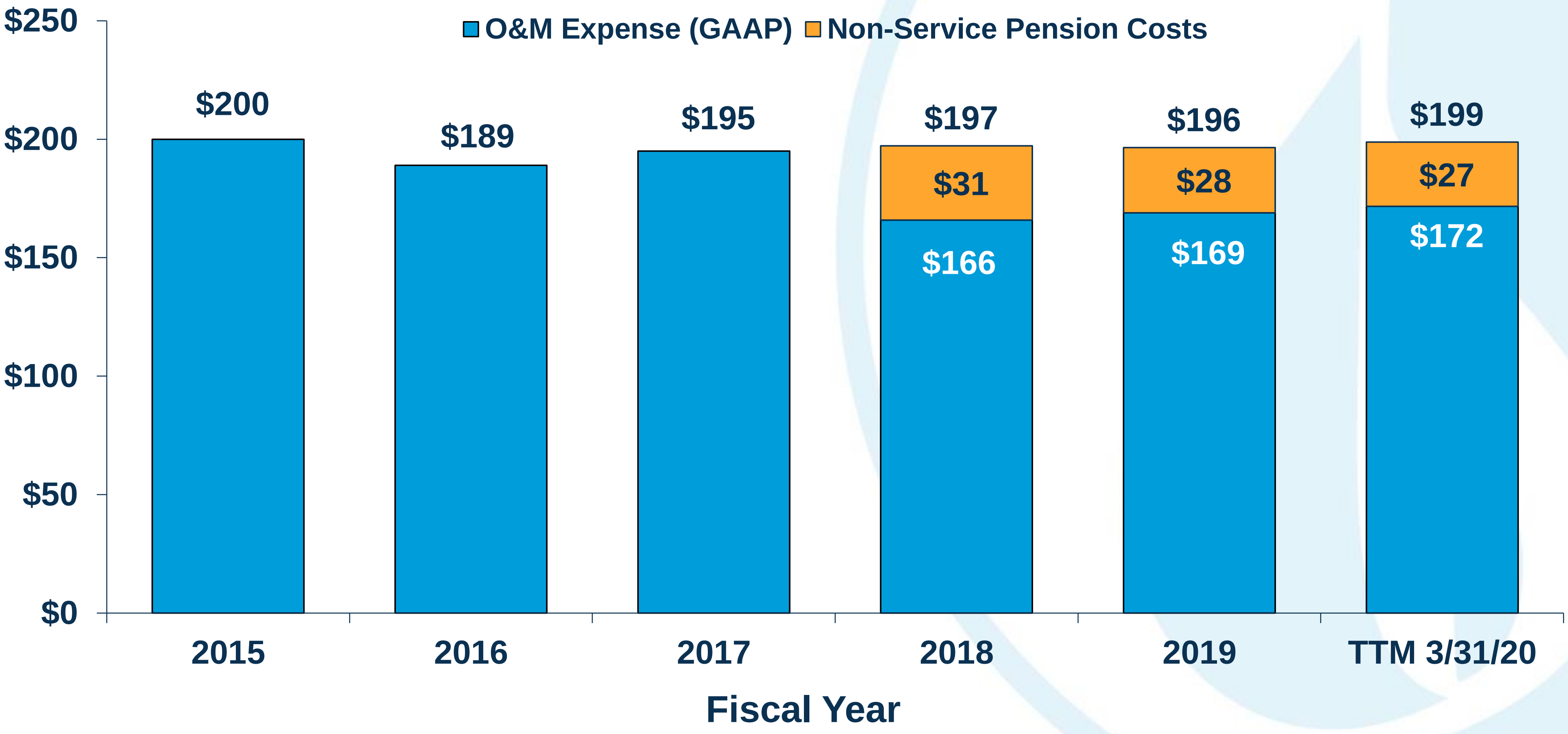
Miles of Utility Main Pipeline Replaced



(1) All values are reported on a calendar year basis as of December 31, 2019.

A Proven History of Controlling Costs

Utility O&M Expense and Non-Service Pension Costs ($ millions)(1)



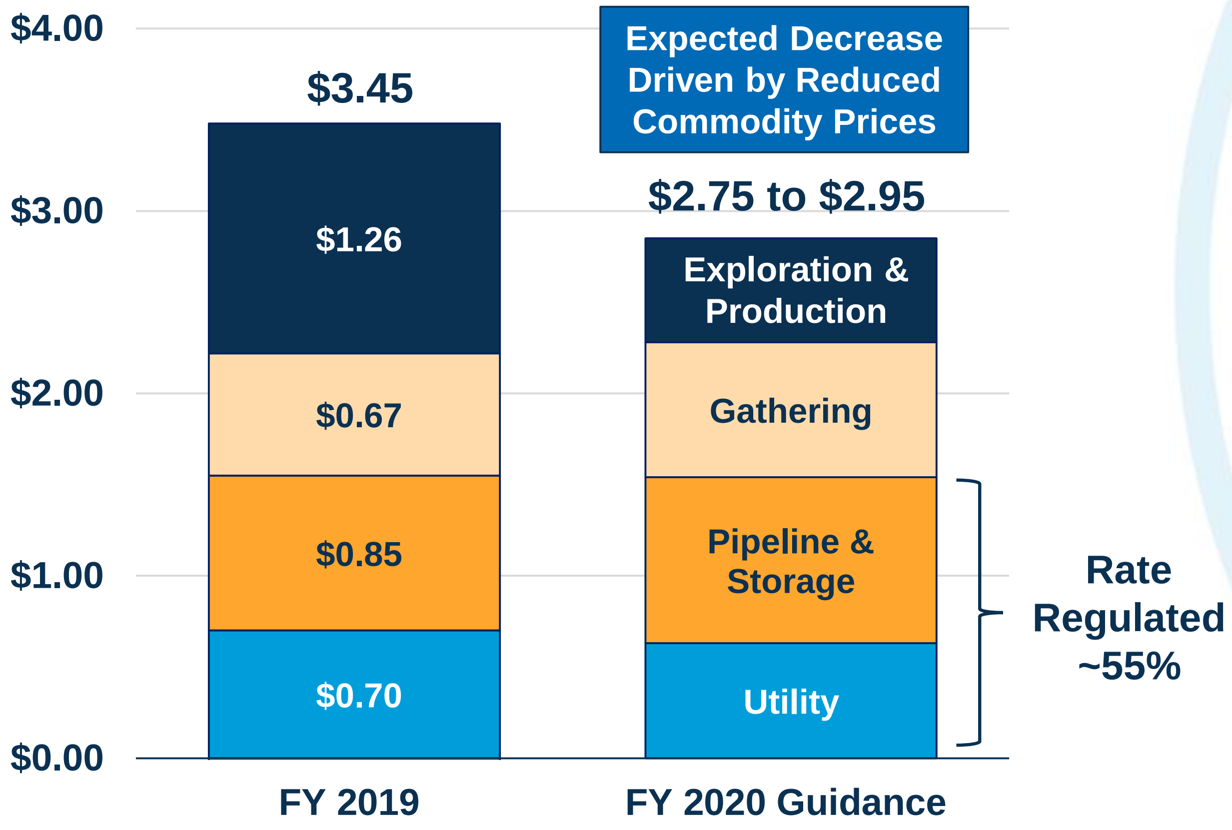
(1) As of October 1, 2018, Operation and Maintenance Expense does not include non-service pension costs, which were re-classified as Other Income (Deductions) on the Company's Income Statement.

Consolidated Financial Overview

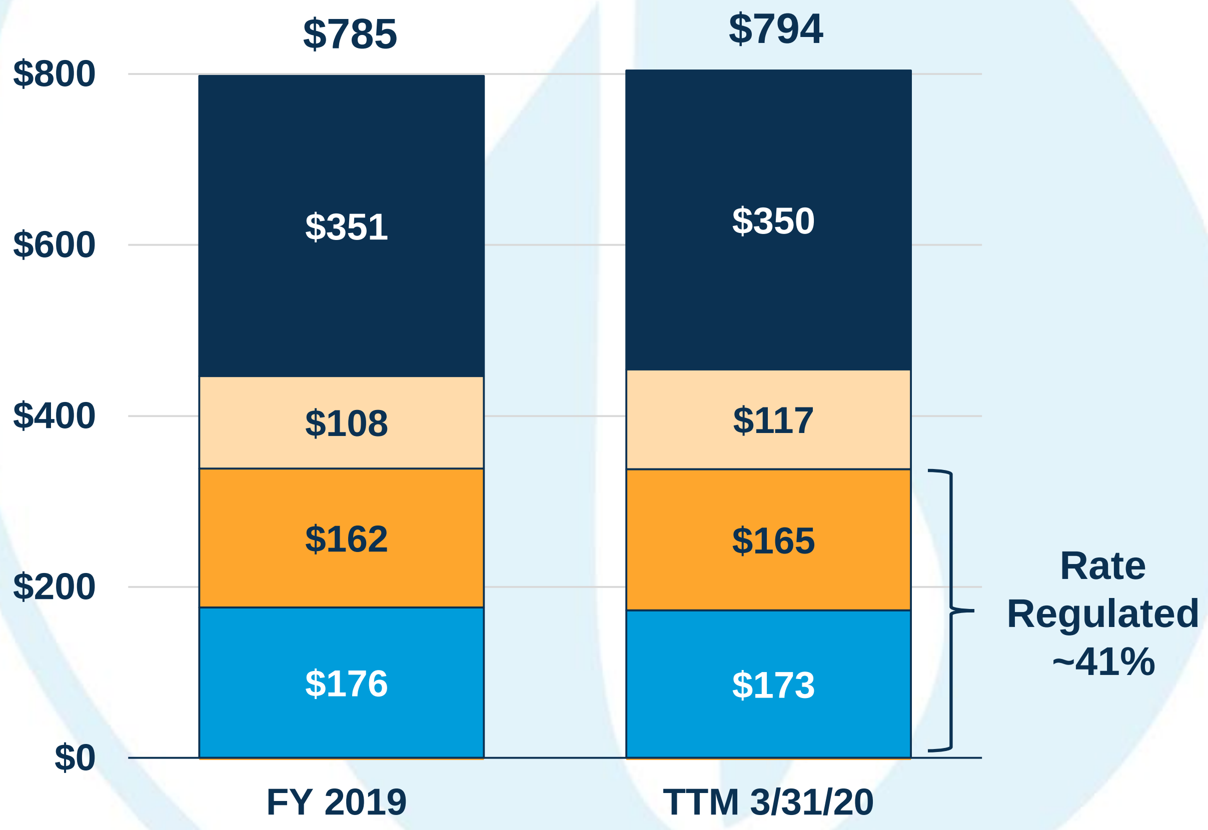
Upstream | Midstream | Downstream

Diversified, Balanced Earnings and Cash Flows

Adjusted Operating Results ($ per share)[1]



Adjusted EBITDA ($ millions)[2]

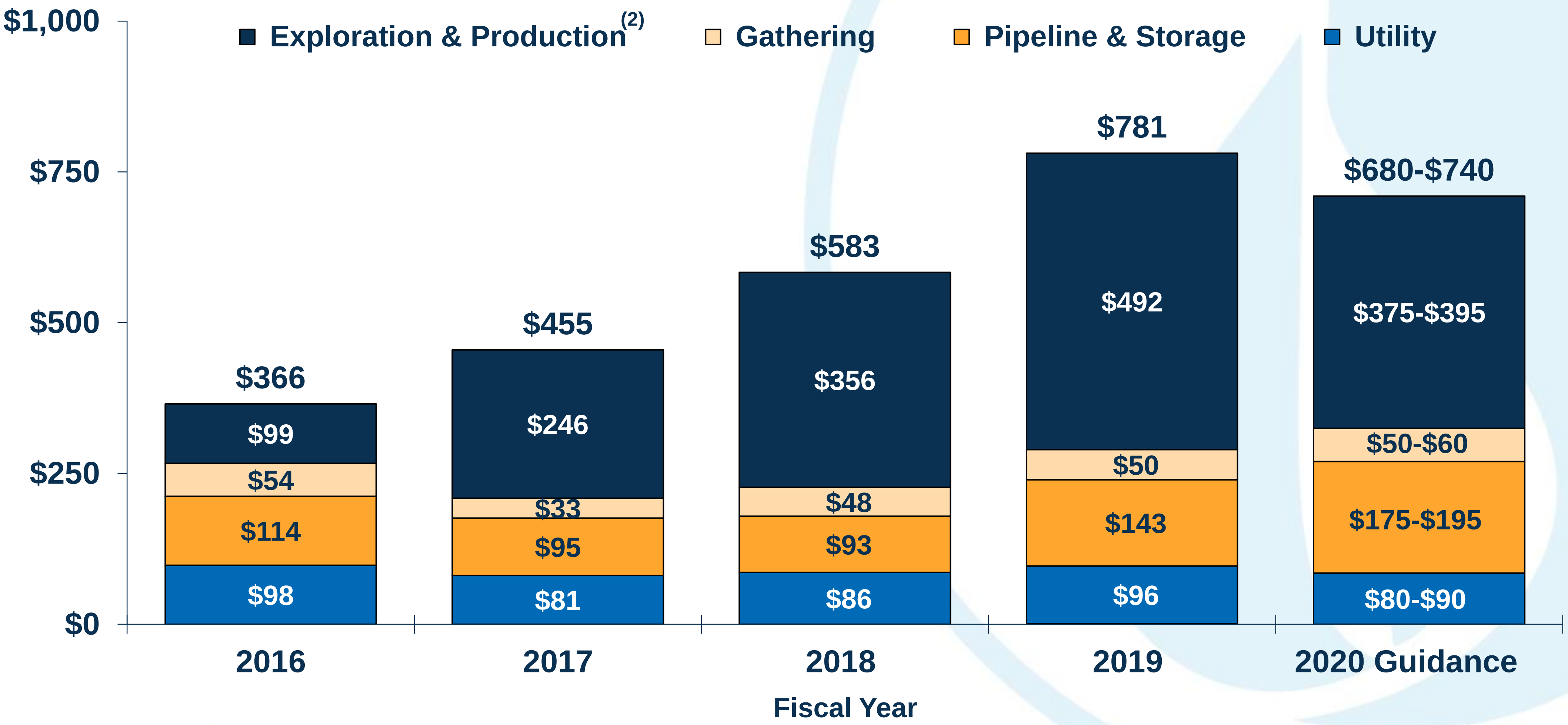


(1) A reconciliation of Adjusted Operating Results to Earnings per Share, by segment, as presented on the Consolidated Statement of Income and Earnings Reinvested in the Business is included at the end of this presentation.
(2) Consolidated Adjusted EBITDA includes Corporate & All Other Segments. A reconciliation of Adjusted EBITDA to Net Income, by segment, 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

National Fuel

Capital Expenditures by Segment ($ millions)(1)

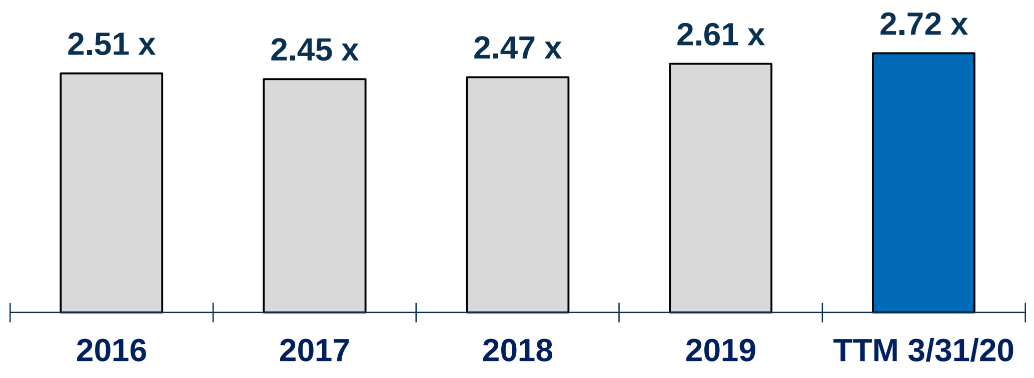


(1) Total Capital Expenditures include Corporate and All Other. A reconciliation to Capital Expenditures as presented on the Consolidated Statement of Cash Flows is included at the end of this presentation.

(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.

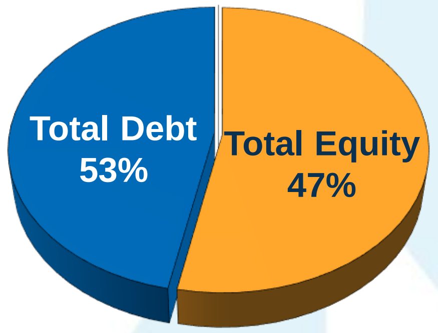
Maintaining Strong Balance Sheet & Liquidity

Net Debt / Adjusted EBITDA(1)



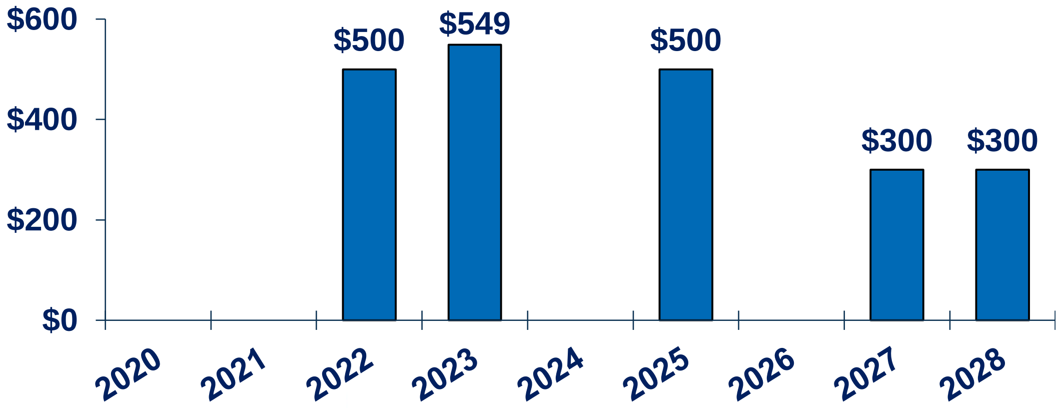
Fiscal Year End

Capitalization



$4.4 Billion Total Capitalization as of March 31, 2020

Debt Maturity Profile ($MM)



Liquidity

Multi-Year Committed Credit Facility	$ 750 MM
Short-term Debt Outstanding	(230 MM)
Available Short-term Credit Facilities	520 MM
Cash Balance at 3/31/20	112 MM
Total Liquidity at 3/31/20	**$ 632 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

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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: impairments under the SEC's full cost ceiling test for natural gas and oil reserves; changes in the price of natural gas or oil; financial and economic conditions, including the availability of credit, and occurrences affecting the Company's ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company's credit ratings and changes in interest rates and other capital market conditions; the length and severity of the recent COVID-19 pandemic, including its impacts across our businesses on demand, operations, global supply chains and liquidity; 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; 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; delays or changes in costs or plans with respect to Company projects or related projects of other companies, including disruptions due to COVID-19, as well as 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 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; the impact of information technology disruptions, cybersecurity or data security breaches; 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; 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; 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. 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, 2019 and the Forms 10-Q for the quarters ended December 31, 2019 and March 31, 2020. 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.

Consolidated Seneca and Gathering Economics

	Prospect	Reservoir	Locations Remaining to Be Drilled	Average Completed Lateral Length (ft)	EUR (Bcf/1000')	Average CAPEX ($M/1000')	Realized Pricing [2] $2.50 IRR (%) [3]	Realized Pricing [2] $2.25 IRR (%) [3]	Realized Pricing [2] $2.00 IRR (%) [3]	15% IRR [3] Realized Price
EDA	**Tract 100 & Gamble** *Lycoming Co.*	**Marcellus**	30-35	5,500 - 6,000	2.5-2.9	$1,050-$1,100	**89%**	**73%**	**59%**	**$1.11**
EDA	**Tract 007** *Tioga Co.*	**Utica**	35-40	8,500 - 9,000	2.0-2.3	$1,250-$1,300	**63%**	**51%**	**41%**	**$1.40**
WDA	**CRV Return Trip**	**Utica**	70-75	9,000-10,000	1.6-1.7	$900-$950	**39%**	**30%**	**25%**	**$1.60**
WDA	**CRV Return Trip**	**Marcellus**	10-15	8,500-9,500	1.1-1.2	$675-$725	**42%**	**33%**	**26%**	**$1.57**

Over 1,000 Potential Additional Marcellus and Utica Locations Economic on a Stand-Alone Basis at ~$2.00/MMBtu[1]

(1) Stand-alone Seneca breakeven economics (15% pre-tax IRR) by prospect are as follows: Tract 100 & Gamble: $1.51; Tract 007: $1.74; CRV Return Trip (Utica): $2.00; CRV Return Trip (Marcellus): $1.95. Internal Rate of Return (IRR) for stand-alone Seneca is pre-tax and includes estimated well costs under current cost structure, LOE, and Gathering tariffs anticipated for each prospect.
(2) 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.
(3) Consolidated Seneca and Gathering IRR is pre-tax and includes expected gathering capital expenditures, well costs under current cost structure, and non-gathering LOE.

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Hedge Positions and Prices

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

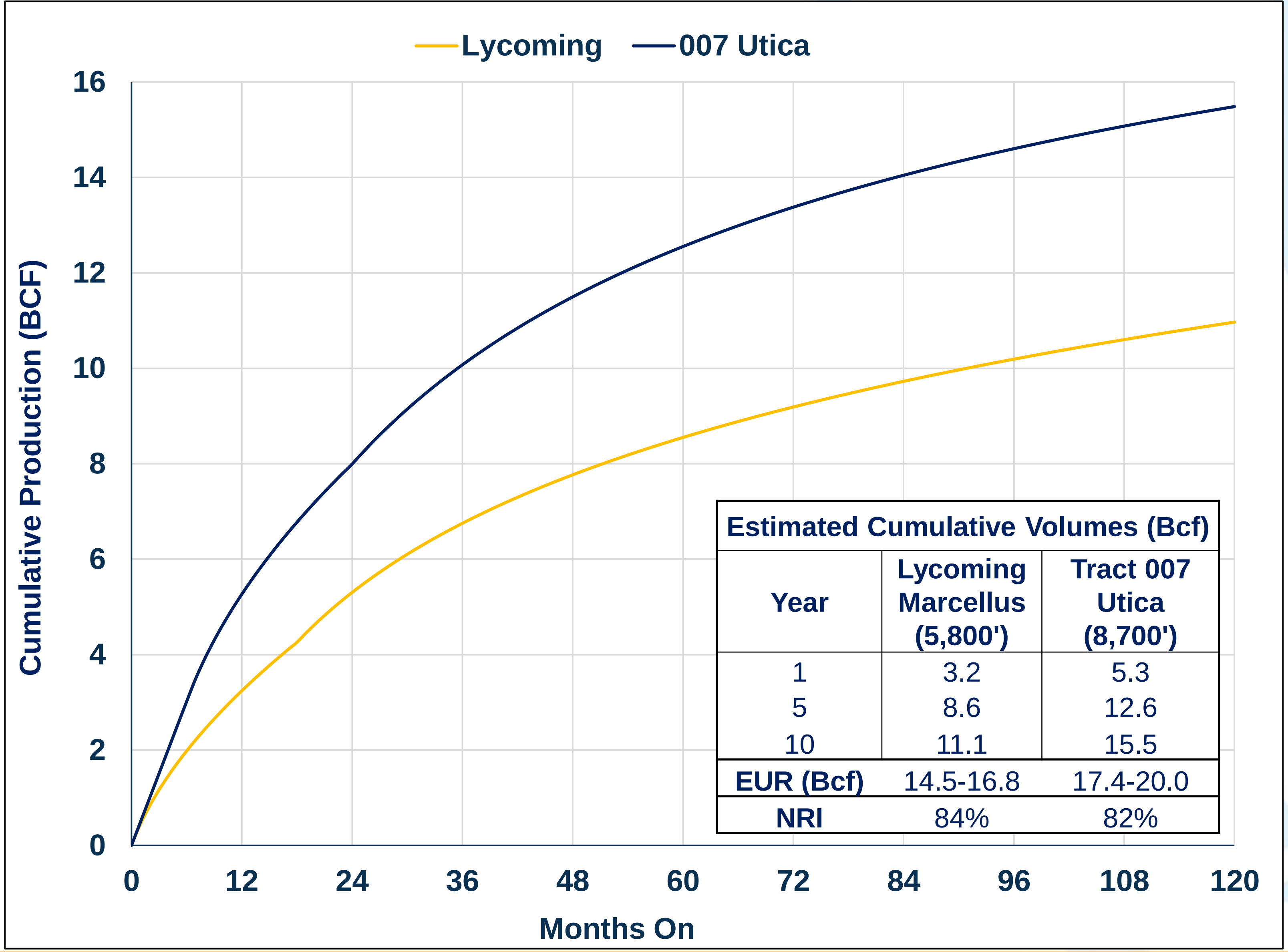
	Fiscal 2020 (Remain.)		Fiscal 2021		Fiscal 2022	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
NYMEX Swaps	45,700	$2.67	117,920	$2.61	62,550	$2.52
Dawn Swaps	3,600	$3.00	600	$3.00	-	-
2-Way Collars	-	-	25,850	$2.28 / $2.77	2,350	$2.28 / $2.77
Fixed Price Physical (1)	29,608	$2.18	46,811	$2.22	40,589	$2.23
Total	**78,908**		**191,181**		**105,489**	

Crude Oil Volumes & Prices in Bbl

	Fiscal 2020		Fiscal 2021		Fiscal 2022	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
Brent Swaps	690,000	$64.55	696,000	$64.29	300,000	$60.07
NYMEX Swaps	162,000	$50.52	156,000	$51.00	156,000	$51.00
Total	**852,000**	**$61.88**	**852,000**	**$61.86**	**456,000**	**$56.97**

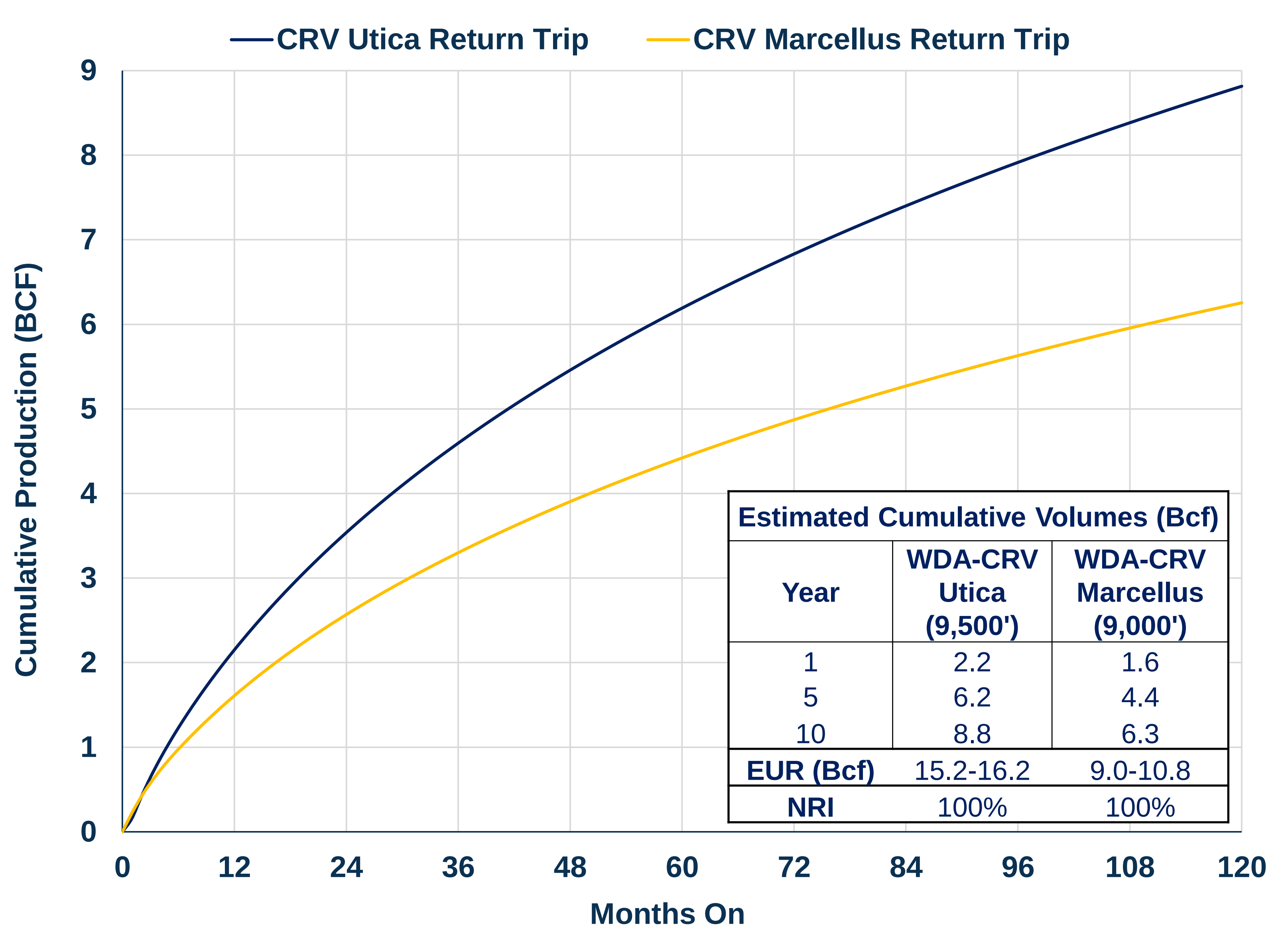
(1) Fixed price physical sales exclude joint development partner's share of fixed price contract WDA volumes as specified under the joint development agreement.

EDA Type Curves



Estimated Cumulative Volumes (Bcf)		
Year	Lycoming Marcellus (5,800')	Tract 007 Utica (8,700')
1	3.2	5.3
5	8.6	12.6
10	11.1	15.5
EUR (Bcf)	14.5-16.8	17.4-20.0
NRI	84%	82%

WDA-CRV Type Curves



Estimated Cumulative Volumes (Bcf)		
Year	WDA-CRV Utica (9,500')	WDA-CRV Marcellus (9,000')
1	2.2	1.6
5	6.2	4.4
10	8.8	6.3
EUR (Bcf)	15.2-16.2	9.0-10.8
NRI	100%	100%

Firm Transportation Commitments

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		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	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*	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.

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.

The Company's fiscal 2020 earnings guidance range does not include the impact of certain items that impacted the comparability of earnings during the six months ended March 31, 2020. While the Company expects to incur additional ceiling test impairment charges in the remaining quarters of fiscal 2020, the amount of these charges is not reasonably determinable at this time. The amount of any ceiling test charge is determined at the end of the applicable quarter and will depend on many factors, including additions to or subtractions from proved reserves, fluctuations in oil and gas prices, and income tax effects related to the differences between the book and tax basis of the Company's oil and gas properties. Some or all of these factors are likely to be significant. Because the expected ceiling test impairment charges and other potential items impacting comparability are not reasonably determinable at this time, the Company is unable to provide earnings guidance other than on a non-GAAP basis that excludes these items.

Non-GAAP Reconciliations – Adjusted EBITDA

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

	FY 2016	FY 2017	FY 2018 (1)	FY 2019 (1)	12-Months Ended 3/31/20
Total Adjusted EBITDA					
Exploration & Production Adjusted EBITDA	$ 363,438	$ 361,079	$ 317,707	$ 351,159	349,631
Pipeline & Storage Adjusted EBITDA	199,446	180,328	183,972	162,181	165,118
Gathering Adjusted EBITDA	78,685	94,380	91,937	108,292	116,719
Utility Adjusted EBITDA	148,683	151,078	175,554	176,134	172,532
Corporate & All Other Adjusted EBITDA	(8,238)	(11,805)	(7,704)	(12,393)	(9,794)
Total Adjusted EBITDA	**$ 782,014**	**$ 775,060**	**$ 761,466**	**$ 785,373**	**$ 794,206**
Total Adjusted EBITDA	**$ 782,014**	**$ 775,060**	**$ 761,466**	**$ 785,373**	**$ 770,299**
Minus: Interest Expense	(121,044)	(119,837)	(114,522)	(106,756)	(107,339)
Plus: Other Income (Deductions)	14,055	11,156	(21,174)	(15,542)	(20,541)
Minus: Income Tax Expense	232,549	(160,682)	7,494	(85,221)	(100,769)
Minus: Depreciation, Depletion & Amortization	(249,417)	(224,195)	(240,961)	(275,660)	(298,572)
Minus: Impairment of Oil and Gas Properties (E&P)	(948,307)	-	-	-	(177,761)
Plus: Reversal of Stock-Based Compensation (all segments)	-	-	-	-	-
Minus: Unrealized Gain (Loss) on Hedge Ineffectiveness	392	(100)	(782)	2,096	2,333
Minus: Joint Development Agreement Professional Fees (E&P)	(7,855)	-	-	-	-
Rounding	-	-	-	-	-
Consolidated Net Income	**$ (297,613)**	**$ 281,402**	**$ 391,521**	**$ 304,290**	**$ 91,557**
Consolidated Debt to Total Adjusted EBITDA					
Long-Term Debt, Net of Current Portion (End of Period)	$ 2,099,000	$ 2,099,000	$ 2,149,000	$ 2,149,000	$ 2,149,000
Current Portion of Long-Term Debt (End of Period)	-	300,000	-	-	-
Notes Payable to Banks and Commercial Paper (End of Period)	-	-	-	55,200	230,000
Less: Cash and Temporary Cash Investments (End of Period)	(129,972)	(555,530)	(229,606)	(20,428)	(111,655)
Total Net Debt (End of Period)	$ 1,969,028	$ 1,843,470	$ 1,919,394	$ 2,183,772	$ 2,267,345
Long-Term Debt, Net of Current Portion (Start of Period)	2,099,000	2,099,000	2,099,000	2,149,000	2,149,000
Current Portion of Long-Term Debt (Start of Period)	-	-	300,000	-	-
Notes Payable to Banks and Commercial Paper (Start of Period)	-	-	-	-	-
Less: Cash and Temporary Cash Investments (Start of Period)	(113,596)	(129,972)	(555,530)	(229,606)	(100,643)
Total Net Debt (Start of Period)	$ 1,985,404	$ 1,969,028	$ 1,843,470	$ 1,919,394	$ 2,048,357
Average Total Net Debt	**$ 1,977,216**	**$ 1,906,249**	**$ 1,881,432**	**$ 2,051,583**	**$ 2,157,851**
Average Total Net Debt to Total Adjusted EBITDA	**2.53 x**	**2.46 x**	**2.47 x**	**2.61 x**	**2.72 x**

(1) Total Adjusted EBITDA for FY 2018, FY 2019, 12 months ended March 31, 2020, include the reclassification of non-service pension costs from Operating and Maintenance Expense to Other Income (Deductions) as of October 1, 2018 on the Company's Income Statement. This reclassification is not reflected in Total Adjusted EBITDA for FY 2016 or FY 2017.

Non-GAAP Reconciliations – Adjusted EBITDA, by Segment

Reconciliation of Adjusted EBITDA to Net Income, by Segment

($ Thousands)	FY 2019	FY20 FYTD	FY19 FYTD	12-Months Ended 3/31/20
Exploration and Production Segment				
Reported GAAP Earnings	$ 111,807	$ (151,299)	$ 60,087	$ (99,579)
Depreciation, Depletion and Amortization	154,784	89,284	70,588	173,480
Other (Income) Deductions	(1,091)	349	(554)	(188)
Interest Expense	54,777	28,220	26,711	56,286
Income Taxes	32,978	27,632	16,406	44,204
Mark-to-Market Adjustment due to Hedge Ineffectiveness	(2,096)	-	237	(2,333)
Impairment of Oil and Gas Properties	-	177,761	-	177,761
Adjusted EBITDA	**$ 351,159**	**$ 171,947**	**$ 173,475**	**$ 349,631**
Pipeline and Storage Segment				
Reported GAAP Earnings	$ 74,011	$ 40,192	$ 42,851	$ 71,352
Depreciation, Depletion and Amortization	44,947	24,960	22,407	47,500
Other (Income) Deductions	(9,157)	(2,739)	(3,899)	(7,997)
Interest Expense	29,142	14,264	14,786	28,620
Income Taxes	23,238	15,366	12,961	25,643
Adjusted EBITDA	**$ 162,181**	**$ 92,043**	**$ 89,106**	**$ 165,118**
Gathering Segment				
Reported GAAP Earnings	$ 58,413	$ 35,842	$ 26,872	$ 67,383
Depreciation, Depletion and Amortization	20,038	10,418	9,351	21,105
Other (Income) Deductions	(460)	(14)	(232)	(242)
Interest Expense	9,406	4,379	4,723	9,062
Income Taxes	20,895	8,348	9,832	19,411
Adjusted EBITDA	**$ 108,292**	**$ 58,973**	**$ 50,546**	**$ 116,719**
Utility Segment				
Reported GAAP Earnings	$ 60,871	$ 58,082	$ 61,237	$ 57,716
Depreciation, Depletion and Amortization	53,832	27,382	26,656	54,558
Other (Income) Deductions	24,021	17,906	17,834	24,093
Interest Expense	23,443	11,190	12,157	22,476
Income Taxes	13,967	18,095	18,373	13,689
Adjusted EBITDA	**$ 176,134**	**$ 132,655**	**$ 136,257**	**$ 172,532**
Corporate and All Other				
Reported GAAP Earnings	$ (812)	$ (2,294)	$ 2,209	$ (5,315)
Depreciation, Depletion and Amortization	2,059	786	916	1,929
Other (Income) Deductions	2,229	5,018	2,372	4,875
Interest Expense	(10,012)	(3,897)	(4,804)	(9,105)
Income Taxes	(5,857)	(1,200)	(4,879)	(2,178)
Adjusted EBITDA	**$ (12,393)**	**$ (1,587)**	**$ (4,186)**	**$ (9,794)**

Non-GAAP Reconciliations – Adjusted Operating Results

(in thousands except per share amounts)	Fiscal Year Ended September 30, 2019	2018
Reported GAAP Earnings	$ 304,290	$ 391,521
Items impacting comparability		
Remeasurement of deferred income taxes under 2017 Tax Reform	(5,000)	(103,484)
Mark-to-market adjustments due to hedge ineffectiveness (E&P)	(2,096)	782
Tax impact of mark-to-market adjustments due to hedge ineffectiveness	440	(192)
Unrealized (gain) loss on other investments (Corporate / All Other)	2,045	—
Tax impact of unrealized (gain) loss on other investments	(429)	—
Premium paid on early redemption of debt (E&P)		962
Tax impact of premium paid on early redemption of debt		(235)
Adjusted Operating Results	$ 299,250	$ 289,354
Reported GAAP Earnings per share	$ 3.51	$ 4.53
Items impacting comparability		
Remeasurement of deferred income taxes under 2017 Tax Reform	(0.06)	(1.20)
Mark-to-market adjustments due to hedge ineffectiveness, net of tax (E&P)	(0.02)	0.01
Unrealized (gain) loss on other investments, net of tax (Corporate / All Other)	0.02	—
Premium paid on early redemption of debt, net of tax (E&P)	—	0.01
Adjusted Operating Results per share	$ 3.45	$ 3.35

(in thousands except per share amounts)	Three Months Ended March 31, 2020	2019	Six Months Ended March 31, 2020	2019
Reported GAAP Earnings	$ (106,068)	$ 90,595	$ (19,477)	$ 193,256
Items impacting comparability:				
Impairment of oil and gas properties (E&P)	177,761	—	177,761	—
Tax impact of impairment of oil and gas properties	(48,503)	—	(48,503)	—
Deferred tax valuation allowance	56,770	—	56,770	—
Remeasurement of deferred income taxes under 2017 Tax Reform	—	—	—	(5,000)
Mark-to-market adjustments due to hedge ineffectiveness (E&P)	—	6,742	—	237
Tax impact of mark-to-market adjustments due to hedge ineffectiveness	—	(1,416)	—	(50)
Unrealized (gain) loss on other investments (Corporate / All Other)	5,414	(3,831)	6,433	2,516
Tax impact of unrealized (gain) loss on other investments	(1,137)	805	(1,351)	(528)
Adjusted Operating Results	$ 84,237	$ 92,895	$ 171,633	$ 190,431
Reported GAAP Earnings Per Share	$ (1.23)	$ 1.04	$ (0.23)	$ 2.23
Items impacting comparability:				
Impairment of oil and gas properties, net of tax (E&P)	1.49	—	1.49	—
Deferred tax valuation allowance	0.66	—	0.66	—
Remeasurement of deferred income taxes under 2017 Tax Reform	—	—	—	(0.06)
Mark-to-market adjustments due to hedge ineffectiveness, net of tax (E&P)	—	0.06	—	—
Unrealized (gain) loss on other investments, net of tax (Corporate / All Other)	0.05	(0.03)	0.06	0.02
Rounding	—	—	—	0.01
Adjusted Operating Results Per Share	$ 0.97	$ 1.07	$ 1.98	$ 2.20

Non-GAAP Reconciliations – Capital Expenditures

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

	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020 Forecast
Capital Expenditures					
Exploration & Production Capital Expenditures	$ 256,104	$ 253,057	$ 380,677	$ 491,889	$375,000 - $395,000
Pipeline & Storage Capital Expenditures	$ 114,250	$ 95,336	$ 92,832	$ 143,003	$175,000 - $195,000
Gathering Segment Capital Expenditures	$ 54,293	$ 32,645	$ 61,728	$ 49,650	$50,000 - $60,000
Utility Capital Expenditures	$ 98,007	$ 80,867	$ 85,648	$ 95,847	$80,000 - $90,000
Corporate & All Other Capital Expenditures	$ 397	$ 212	$ 222	$ 855	
Eliminations	$ -	$ -	$ (20,505)		
Total Capital Expenditures from Continuing Operations	$ 523,051	$ 462,117	$ 600,602	$ 781,246	$680,000 - $740,000
Plus (Minus) Accrued Capital Expenditures					
Exploration & Production FY 2019 Accrued Capital Expenditures				$ (38,063)	
Exploration & Production FY 2018 Accrued Capital Expenditures			$ (51,343)	$ 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	-			
Pipeline & Storage FY 2019 Accrued Capital Expenditures				$ (23,771)	
Pipeline & Storage FY 2018 Accrued Capital Expenditures			$ (21,861)	$ 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	-			
Gathering FY 2019 Accrued Capital Expenditures				$ (6,595)	
Gathering FY 2018 Accrued Capital Expenditures			$ (6,084)	$ 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	-			
Utility FY 2019 Accrued Capital Expenditures				$ (12,692)	
Utility FY 2018 Accrued Capital Expenditures			$ (9,525)	$ 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	-			
Total Accrued Capital Expenditures	$ 58,525	$ (11,782)	$ (16,597)	$ 7,692	
Total Capital Expenditures per Statement of Cash Flows	**$ 581,576**	**$ 450,335**	**$ 584,004**	**$ 788,938**	**$680,000 - $740,000**

Non-GAAP Reconciliations – E&P Operating Expenses

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	Twelve Months Ended September 30, 2019						Twelve Months Ended September 30, 2018					
	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]	$118,023	$0	$118,023	$0.60	$0.00	$0.56	$95,611	$267	$95,878	$0.60	$0.09	$0.54
Other Lease Operating Expense	$13,474	$55,129	$68,604	$0.07	$20.81	$0.32	$14,604	$52,240	$66,844	$0.09	$17.82	$0.38
Lease Operating and Transportation Expense	$131,497	$55,129	$186,626	$0.67	$20.81	$0.88	$110,215	$52,507	$162,721	$0.69	$17.91	$0.91
General & Administrative Expense			$64,003			$0.30			$60,596			$0.34
All Other Operating and Maintenance Expense			$11,130			$0.05			$11,077			$0.06
Property, Franchise and Other Taxes			$17,725			$0.08			$14,400			$0.08
Total Taxes & Other			$28,855			$0.14			$25,477			$0.14
Depreciation, Depletion & Amortization			$154,784			$0.73			$124,274			$0.70
Production:												
Gas Production (MMcf)				195,906	1,974	197,880				160,499	2,407	162,906
Oil Production (MBbl)				3	2,320	2,323				4	2,531	2,535
Total Production (Mmcfe)				195,926	15,893	211,819				160,523	17,592	178,114
Total Production (Mboe)				32,654	2,649	35,303				26,754	2,932	29,686

(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.