Disclosure Update

2019 Guidance Details

February 19, 2019

Cautionary Language

Risk Factors. *This presentation, including the oral statements made in connection herewith, contains forward-looking statements, estimates and projections within the meaning of the federal securities laws. Statements that are not historical are forward-looking and may include our operational and strategic plans; estimates of gas reserves and resources; projected timing and rates of return of future investments; and projections and estimates of future production, revenues, income and capital spending. These forward-looking statements involve risks and uncertainties that could cause actual results to differ materially from those statements, estimates and projections. Investors should not place undue reliance on forward-looking statements as a prediction of future actual results. The forward-looking statements in this presentation speak only as of the date of this presentation; we disclaim any obligation to update the statements, and we caution you not to rely on them unduly.*

Specific factors that could cause future actual results to differ materially from the forward-looking statements are described in detail under the captions "Forward Looking Statements" and "Risk Factors" in our annual report on Form 10-K for the year ended December 31, 2018 filed with the SEC, as supplemented by our quarterly reports on Form 10-Q. Those risk factors discuss, among other matters, pricing volatility or pricing decline for natural gas and NGLs; operational risks relating to midstream facilities, pipeline systems, drilling natural gas wells, access to key services and equipment, access to adequate water sources and customer interactions; the impact of laws and regulations on our business and industry; competitive and economic concerns; risks associated with our debt and hedging strategy; our ability to acquire economically recoverable natural gas reserves; challenges associated with strategic determinations, including the allocation of capital to strategic opportunities; our development and exploration projects and potential acquisitions or divestitures, as well as CNXM's midstream system development.

Reserves. *Currently, the SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible oil and gas reserves that a company anticipates as of a given date to be economically and legally producible and deliverable by application of development projects to known accumulations. We may use certain terms in this presentation, such as EUR (estimated ultimate recovery), unproved reserves and total resource potential, that the SEC's rules strictly prohibit us from including in filings with the SEC. We caution you that the SEC views such estimates as inherently unreliable and these estimates may be misleading to investors unless the investor is an expert in the natural gas industry. These measures are by their nature more speculative than estimates of reserves prepared in accordance with SEC definitions and guidelines and accordingly are less certain. We also note that the SEC strictly prohibits us from aggregating proved, probable and possible reserves in filings with the SEC due to the different levels of certainty associated with each reserve category.*

Title. *Except for proved reserve data, the information included in this presentation is based on a summary review of the title to the gas rights we hold. As is customary in the gas industry, prior to the commencement of natural gas drilling operations on our properties, we conduct a thorough title examination and perform curative work with respect to significant defects. We are typically responsible for curing any title defects at our expense. As a result of our title review or otherwise, we may be required to acquire property rights from third parties at our expense in order to effectively drill and produce the gas rights we control and third parties may participate in the wells we drill, thereby reducing our working interest in those wells.*

Reconciliation. *As it relates to the disclosures within this presentation of projected Adjusted EBITDA and EBITDAX for fiscal or quarterly periods in 2019-2022, for CNX or CNXM, CNX Resources is unable to provide a reconciliation of such metrics to projected operating income, the most directly comparable financial measure calculated in accordance with GAAP, due to the unknown effect, timing, and potential significance of certain income statement items for each of CNX and CNXM, respectively.*

Data. *This presentation has been prepared by CNX and includes market data and other statistical information from sources believed by CNX to be reliable, including independent industry publications, government publications and other published independent sources. Some data are also based on CNX's good faith estimates, which are derived from its review of internal sources as well as the independent sources described above. Although CNX believes these sources are reliable, it has not independently verified the information and cannot guarantee its accuracy or completeness.*

Not an Offer. *This presentation does not constitute an offer to sell or a solicitation of offers to buy securities of CNX Resources Corporation or CNX Midstream Partners LP.*

Disclosure Update

2019 minimum guidance issued in the Q4 2018 earnings materials is unchanged

This presentation provides further clarification and transparency related to that guidance

- Specifically, these materials outline the expected well counts and production volumes associated with D&C capital expenditure guidance; i.e. 72 TILs for $600 million of capital in 2019 and $100 million in 2020 to finish the 2019 program

2019 Updates Include:

- Minimum development program well schedule
- Minimum development production cadence
- Carryover wells and related capital expenditures for 2020
- Per unit revenue and operating cost guidance
- 2019 AMT credits and other tax refund guidance

CNX Resources, as the General Partner of CNX Midstream, reaffirms continued 15% annual LP distribution growth target through 2023

FY2019 Minimum Activity by Quarter

	Q1 2019			Q2 2019			Q3 2019			Q4 2019			FY 2019			FY 2020		
	TD	FRAC	TIL	TD	FRAC	TIL	TD	FRAC	TIL	TD	FRAC	TIL	TD	FRAC	TIL	TD	FRAC	TIL
Marcellus	10	13	18	12	11	10	5	15	13	6	6	13	**33**	**45**	**54**	-	6	6
Utica	3	-	-	2	4	-	2	2	5	5	3	2	**12**	**9**	**7**	-	3	5
Total	**13**	**13**	**18**	**14**	**15**	**10**	**7**	**17**	**18**	**11**	**9**	**15**	**45**	**54**	**61**	**-**	**9**	**11**

2019 Program Carryover

Activity that corresponds to D&C capex guidance of $575-$625 million(1)

The 2019 minimum development program would result in 11 DUCs at year-end with expected TIL split between 1Q and 3Q 2020

Expected D&C capex required to frac and TIL the carryover wells is ~$100 million

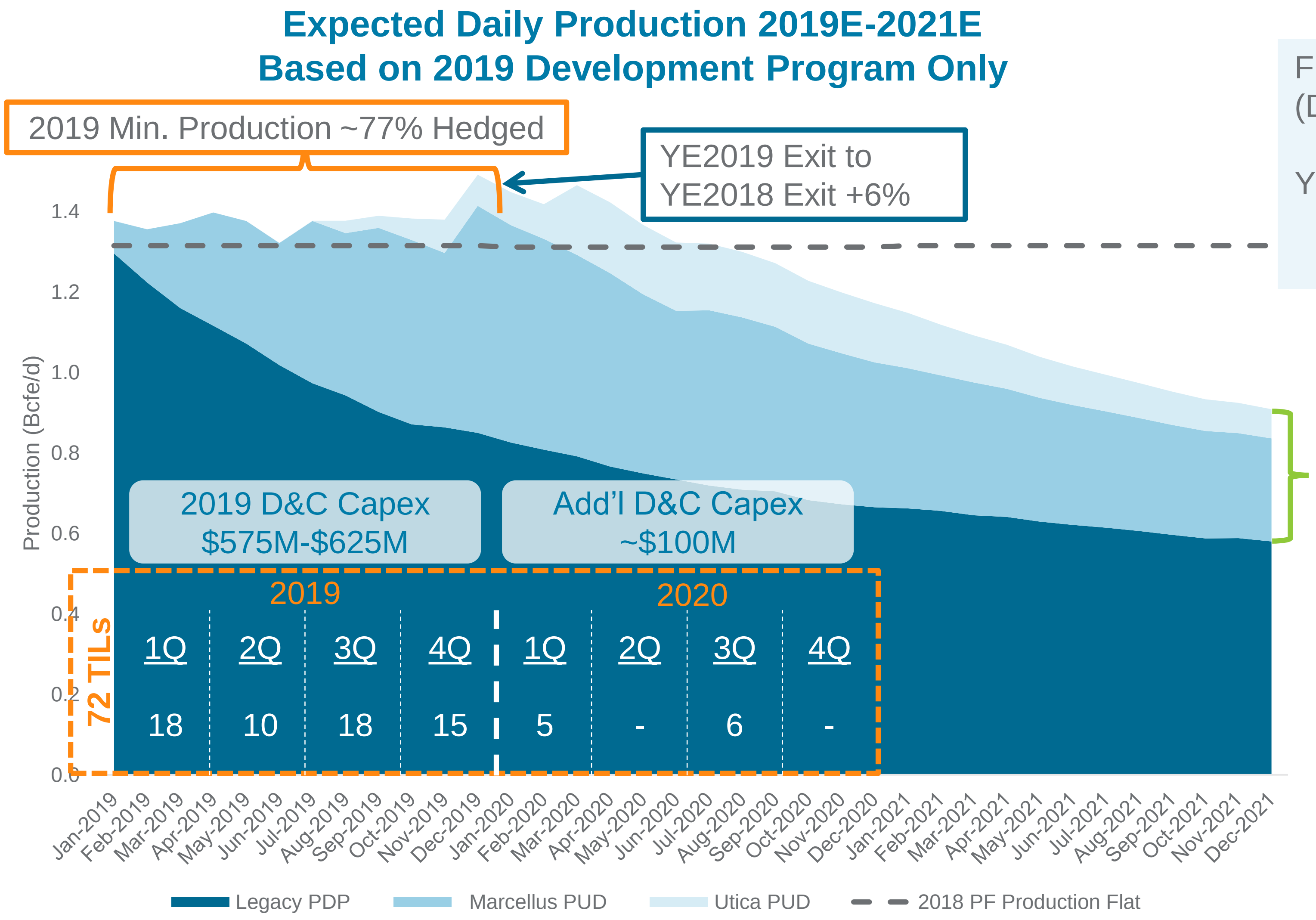
2019 Program TILs by DevCo

	DevCo I	DevCo III
2019	54	5
2020	-	6

$700M D&C CapEx → 72 TILs

(1) D&C capital expenditures includes all costs related to drilling, completions, pad construction, production facilities, water supply, and disposed water flowback.

Expected Cadence of Daily Production for 2019 Minimum Program



Five-year average all-in maintenance capital (D&C + non-D&C): ~$300 million[(1)]

YE2019 to YE2018 PDP Base decline: ~34% increased modestly in 2018 due to sale of mature OH Utica JV and SOG assets

$700 million of D&C capex

72 TILs expected to produce ~700 Bcfe from 2019-2023

700 Bcfe * FY2018 Operating Cash Margin of $1.88[(2)] =

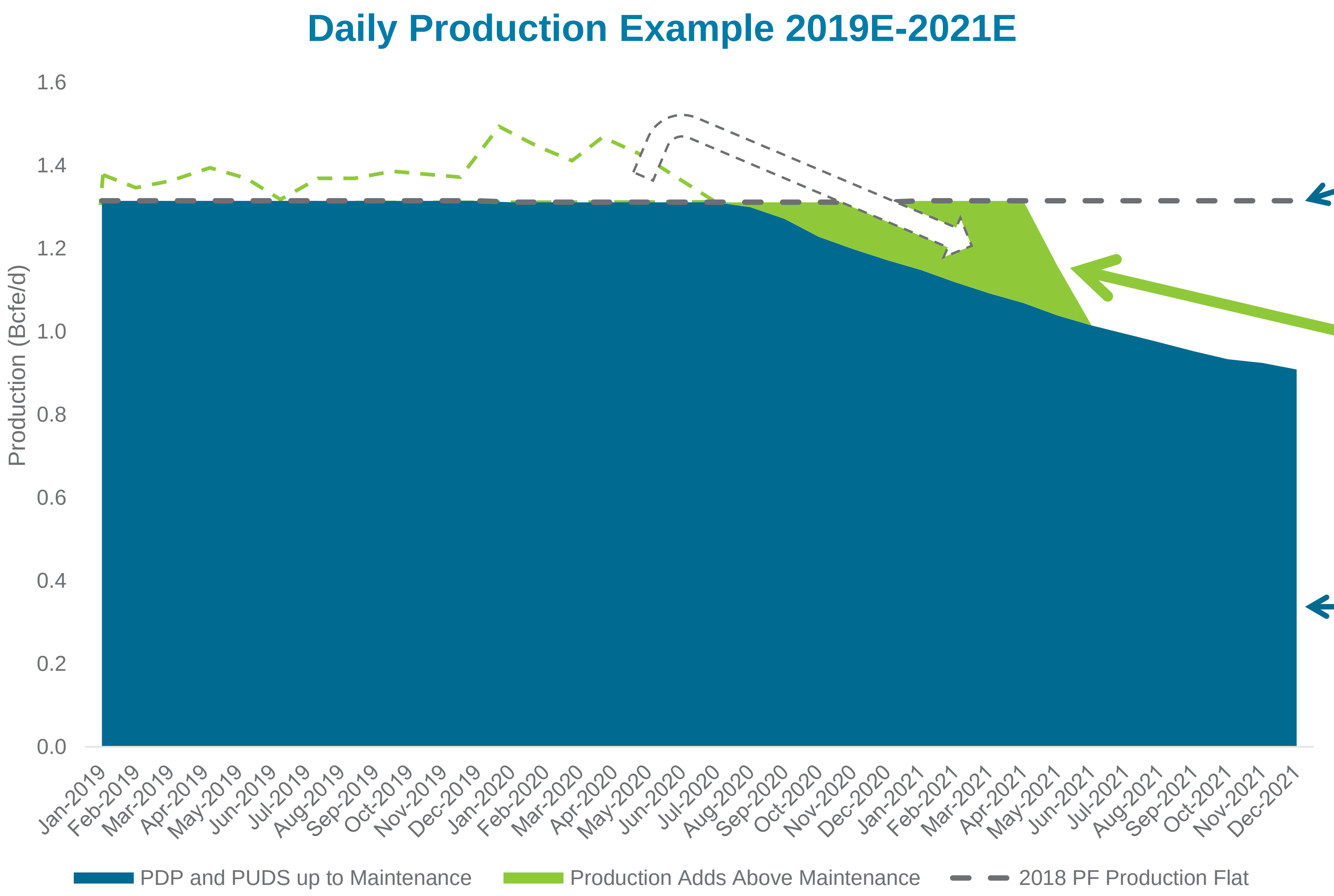
~$1.3 billion in operating profit over five years

Note: Graph based on midpoint of 2019 production volume minimum guidance range of 495-515 Bcfe.

(1) Maintenance capital expenditures includes D&C plus land, water infrastructure, and midstream. Holds flat 2018 pro forma production of 1.315 Bcfe/d.

(2) See Q4 2018 earnings release January 31, 2019; FY2018 total company average sales price of $2.97 less total production cash costs of $1.09 = operating cash margin of $1.88.

2019 Minimum Program Supports Production Equal to ~30 Months Flat



FY2018 pro forma daily average production of 1.315 Bcfe/d held flat

Production adds from 2019 program would be enough to hold 2018 pro forma daily average production flat through May 2021

PDP and PUDs in 2019 program up to FY2018 maintenance level

2019 Minimum Development Program and Capital Breakdown

($ in millions)	CapEx[1]		TILs		Average Lateral Length	
	2019E	2020E	2019E	2020E	2019E	2020E
Marcellus	$515	$40	54	6	9,950’	10,550’
Utica	$85	$60	7	5	6,600’	9,750’
Total	**$600**[2]	**$100**	**61**	**11**	**9,600**	**10,200**

$700M D&C CapEx → 72 TILs

CPA Utica Shaw Pad

- The Shaw 1G well that experienced issues in early 1Q 2019 has been successfully contained
  - Approximately $30 million of capital expenditures related to the Shaw pad are included in the 2019 budget
- The remaining three wells on the Shaw pad are not in the 2019 or 2020 carryover plan, but remain an opportunity for completion and TIL in the near future

This development schedule represents the minimum expected activity for FY2019

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(1) D&C capital expenditures includes all costs related to drilling, completions, pad construction, production facilities, water supply, and disposed water flowback.
(2) Midpoint of 2019 guided minimum capital expenditure range of $575-$625 million.

2019 AMT Credit and Additional Refunds

Combined AMT refund and additional tax refunds to drive cash tax inflow of ~$149 million in 2019

- Approximately $131 million in total AMT refund expected in 2019
  - About $29 million that was expected by year-end 2018 fell into early 2019; incremental $102 million expected by year-end
  - Additional cash tax refunds related to past filings and other miscellaneous recoveries of ~$18 million expected by the end of the year
- Incremental AMT refund expected in 2020 and 2021 of approximately $51 million each year
- Company continues to expect no cash tax payments for 4-5 years due to NOL utilization

	December 31, 2018	December 31, 2017
Current Assets		
Cash and Cash Equivalents	$ 17,198	$ 509,167
Accounts and Notes Receivable		
Trade	252,424	156,817
Other Receivables	11,077	48,908
Supplies Inventories	9,715	10,742
Recoverable Income Taxes	149,481	31,523
Prepaid Expenses	61,791	95,347
Total Current Assets	501,686	852,504

	December 31, 2018	December 31, 2017
Deferred Tax Assets:		
Alternative Minimum Tax	$ 102,482	$ 188,080
Net Operating Loss - Federal	124,341	99,524
Net Operating Loss - State	110,339	107,756
Foreign Tax Credit	43,194	44,402
Interest Limitation	32,147	—
Equity Compensation	13,096	21,866
Gas Well Closing	10,140	55,486
Salary Retirement	9,434	9,404
Capital Lease	1,624	2,020
Other	13,714	11,831
Total Deferred Tax Assets	460,511	540,369
Valuation Allowance	(94,455)	(136,576)
Net Deferred Tax Assets	366,056	403,793

Note: Current Assets and Deferred Tax tables from 2018 10-K.

Reaffirmed 2019 Minimum Guidance

Minimum Capital Expenditures ($ millions)	2019E Low	2019E High
Drilling & Completions	$575	$625
Non-D&C	$175	$175
Total E&P Capital	**$750**	**$800**
CNX Midstream LP Capital	$250	$280
Total Consolidated Capital	$1,000	$1,080

Minimum Production (Bcfe)	Low	High
Total Production Volumes (Bcfe)[(1)]	**495**	**515**
Y/Y Growth (2018 pro forma)[(2)]	*3%*	*7%*

Adjusted EBITDAX[(3)] ($ millions)	Low	High
E&P Standalone + Distributions[(4)]	**$790**	**$825**
Consolidated	$945	$985

Capital budget represents a **minimum set of D&C activity**

Throughout the year, **the company will evaluate a series of factors to determine incremental activity** and will update capital guidance accordingly

Those factors include gas prices, CNX equity prices, supply/demand indicators, Utica data set, M&A opportunities, and company appetite for risk

Includes **~$100 million for water infrastructure** in 2019 with useful life spanning multiple years

CNX Resources is unable to provide a reconciliation of projected Adjusted EBITDAX to projected net income, the most comparable financial measure calculated in accordance with GAAP, due to the unknown effect, timing, and potential significance of certain income statement items.

(1) Expected 5-6% liquids.
(2) Pro forma growth comparing 2019E production with 2018 production from assets not sold of 480 Bcfe.
(3) Forward pricing date as of 1/18/2019.
(4) Includes CNX Midstream LP + GP/IDR distributions of $55 million in FY2019E.

Reaffirmed 2019 Minimum Guidance

	2019E	
Revenue and Other Operating Income	**E&P**	**Consolidated**
Production Volumes:		
Natural Gas (Bcf)	465-485	
NGLs (MBbls)	4,500-4,600	
Condensate (MBbls)	350-400	
Total Production (Bcfe)	**495-515**	
% Liquids	6%	
Natural Gas Basis Differential to NYMEX ($/Mcf)	($0.20)-($0.25)	
NGL Realized Price ($/Bbl)	$20.00-$22.00	
Condensate Realized Price % of WTI	70%	
Realized Hedging Gain/(Loss) ($ in millions) (1)	($120)-($130)	
Other Operating Income (3rd party water income and resold FT) ($ in millions)	$20-$25	
CNXM 3rd Party Gathering Revenue		$55-$65
Costs		
Average per unit operating expenses ($/Mcfe):		
Lease Operating Expense	$0.12-$0.14	
Production, Ad Valorem, and Other Fees	$0.05-$0.06	
Transportation, Gathering and Compression	$0.96-$1.00	$0.62-$0.66
Total Cash Production and Gathering Costs	**$1.13-$1.20**	**$0.79-$0.86**
($ in millions)		
Selling, General, and Administrative Costs(2)	$95-$105	$115-$125
Exploration Expense	$5-$10	
Other Operating Expense (unutilized FT and processing, idle rig fees, and other misc.)	$90-$100	
Other Non-Operating Expense (Income)	($5)-($15)	
Total Capital Expenditures	**$750-$800**	**$1,000-$1,080**
EBITDAX (E&P Standalone + Distributions and Total Consolidated)	**$790-$825**	**$945-$985**
Total Distributions (LP + GP/IDR)	**$55**	

2019 minimum development program is Marcellus-weighted, which has higher transportation, gathering and compression unit costs

Incremental activity in 2019 and Utica growth in 2020 (~$0.40/Mcfe cash production costs) would be expected to drive down total operating costs

Includes idle equipment fees based on minimum development program; incremental activity could reduce idle time/unused capacity and reduce fees

Royalty income, right of way sales, interest income and 'other' all netted against bank fees, other corporate expense, and other land rental expense

CNX Resources is unable to provide a reconciliation of projected Adjusted EBITDAX to projected net income, the most comparable financial measure calculated in accordance with GAAP, due to the unknown effect, timing, and potential significance of certain income statement items.

(1) Refer to Appendix on hedging gain/(loss) assumptions. Forward pricing date as of 1/18/2019. Anticipated hedging activity is not included in projections.

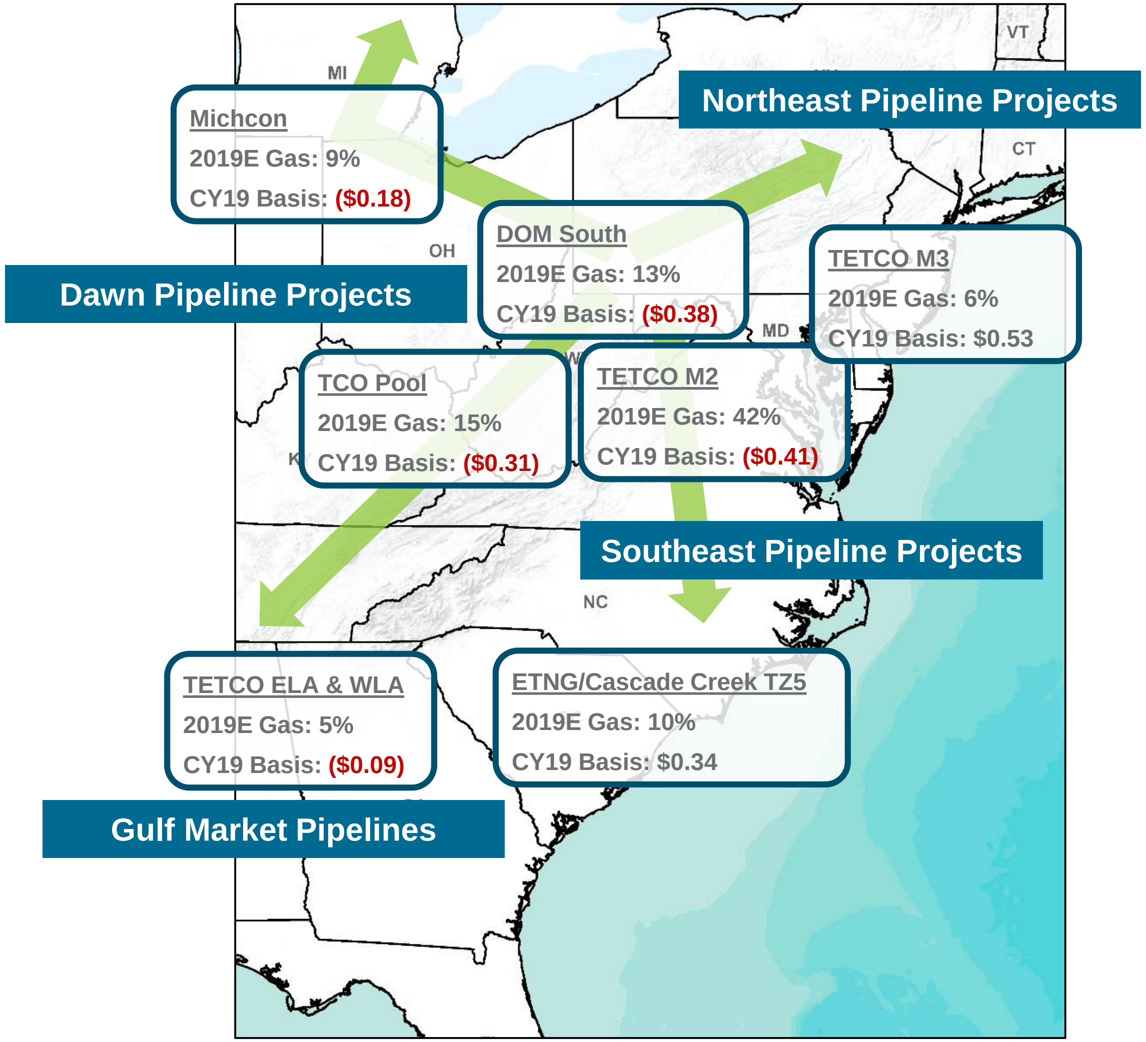
(2) Excludes stock-based compensation.

Financial Guidance: 2019E E&P Revenue Buildup

2019E Revenue					
	Volumes		Realized Price		Revenue ($ in millions)
Natural Gas	475.0	Bcf	$3.05	/Mcf	$1,449
NGLs	4,550.0	MBbls	$21.00	/Bbl	$96
Condensate	375.0	MBbls	$38.00	/Bbl	$14
Realized Hedging Gain/(Loss)					($127)
Total	**505.0**	**Bcfe**	**$2.84**	**/Mcfe**	**$1,432**
Average Daily	1,390.0	MMcfe/d			
Purchased Gas Sales					$40
Other Operating Income					
Water Income (3rd party sales)					$10
Gathering Income (resold unutilized FT)					$10
Total Revenue and Operating Income					**$1,492**

Note: Based on midpoint of guided ranges.
Base plan assumes NYMEX as of 1/18/2019 of $3.07 per MMBtu + weighted average basis of ($0.23) per MMBtu.

Financial Guidance: 2019E Natural Gas Marketing Mix and Basis



Percentages include physical sales

Market	Volumes (000 MMBtu)	2019E Gas Sold (%)	CY 2019 Basis
DOM South	45,975	9%	($0.38)
ETNG Cascade Creek TZ5	5,106	1%	$0.45
ETNG Mainline	1,899	0%	$0.23
TCO Pool	61,663	12%	($0.31)
TETCO ELA & WLA	12,755	3%	($0.09)
TETCO M3	30,636	6%	$0.53
TETCO M2	181,642	36%	($0.41)
Michcon	42,925	8%	($0.18)
Physical basis sales	128,006	25%	($0.11)
Total (000 MMBtu)	**510,607**	**100%**	**($0.23)**
Total (MMcf)	**475,000**		

NYMEX	$3.07
Weighted Average Basis (Not considering hedging)	($0.23)
2019E Average Realized Price (per MMBtu)	$2.84
Conversion Factor (MMBtu/Mcf)	*1.075*
2019E Average Realized Price (per Mcf)	**$3.05**

Note: Forward market prices are as of 1/18/2019.

Q1 2019E Gas Hedging Gain/Loss Projections

	Q1 2019				
	Hedged Volumes (000 MMBtu)	Hedged Price	Forward Market[1]	Forecasted Gain/(Loss) ($/MMBtu)	Forecasted Gain/(Loss) ($ in 000's)
($/MMBtu)					
NYMEX	89,775	$2.86	$3.45	($0.60)	($53,685)
Basis:					
DOM South (DOM)	10,800	($0.59)	($0.27)	($0.32)	($3,489)
TCO Pool (TCO)	10,800	($0.33)	($0.23)	($0.10)	($1,026)
Michcon (NMC)	6,975	($0.18)	($0.11)	($0.07)	($453)
TETCO ELA (TEB)	1,800	($0.09)	($0.12)	$0.03	$61
TETCO WLA (TWB)	1,800	($0.08)	($0.09)	$0.01	$13
TETCO M3 (TMT)	3,275	$0.89	$2.61	($1.72)	($5,633)
TETCO M2 (BM2)	25,200	($0.57)	($0.28)	($0.29)	($7,283)
Total Financial Basis Hedges	60,650				($17,810)
Total Projected Realized Loss					**($71,495)**

Note: Forward market prices, hedged volumes, and hedge prices are as of 1/18/2019. Anticipated hedging activity is not included in projections.
(1) January prices are settled.

2019E Gas Hedging Gain/Loss Projections

	CY2019				
	Hedged Volumes (000 MMBtu)	Hedged Price	Forward Market[1]	Forecasted Gain/(Loss) ($/MMBtu)	Forecasted Gain/(Loss) ($ in 000's)
($/MMBtu)					
NYMEX	386,088	$2.83	$3.07	($0.23)	($90,344)
Basis:					
DOM South (DOM)	43,800	($0.59)	($0.38)	($0.21)	($9,242)
TCO Pool (TCO)	52,360	($0.35)	($0.31)	($0.04)	($2,095)
Michcon (NMC)	32,263	($0.20)	($0.18)	($0.02)	($484)
TETCO ELA (TEB)	7,300	($0.09)	($0.12)	$0.03	$212
TETCO WLA (TWB)	7,300	($0.08)	($0.07)	($0.01)	($102)
TETCO M3 (TMT)	14,813	$0.08	$0.53	($0.45)	($6,651)
TETCO M2 (BM2)	110,610	($0.58)	($0.41)	($0.17)	($18,693)
Total Financial Basis Hedges	268,446				($37,055)
Total Projected Realized Loss					**($127,399)**

- In addition to NYMEX and basis financial hedges, CNX has physical fixed basis sales and physical fixed price sales with customers
- CY 2019 physical fixed basis sales and physical fixed price sales: 119.1 Bcf
- Physical sales provide additional basis hedge
  - Flows through gas sales in financials

Note: Forward market prices, hedged volumes, and hedge prices are as of 1/18/2019. Anticipated hedging activity is not included in projections.
(1) January prices are settled.