

Results Driven. Manufacturing Focused.



Management Presentation

July 2019

www.sanchezenergycorp.com





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When used in this presentation, words such as “will,” “potential,” “believe,” “estimate,” “intend,” “expect,” “may,” “should,” “anticipate,” “could,” “plan,” “predict,” “forecast,” “budget,” “guidance,” “project,” “profile,” “model,” “strategy,” “future” or their negatives or the statements that include these words or other words that convey the uncertainty of future events or outcomes, are intended to identify forward looking statements, although not all forward looking statements contain such identifying words. In particular, statements, express or implied, concerning our future operating results and returns or our ability to replace or increase reserves, increase production, or generate income or cash flows, service our debt and other obligations and repay or otherwise refinance such obligations when due or at maturity, operational and commercial benefits of our partnerships, expected benefits from acquisitions, including the transactions we closed in the first quarter of 2017 (the “Comanche Acquisition”) whereby we, along with an entity controlled by The Blackstone Group, L.P. (“Blackstone”), Gavilan Resources, LLC (“Gavilan”), acquired assets from Anadarko E&P Onshore LLC and Kerr-McGee Oil and Gas Onshore LP (“Anadarko”), and our strategic relationship with Sanchez Midstream Partners LP (“SNMP”) are forward looking statements. Forward looking statements are not guarantees of performance. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond our control. Although we believe that the expectations reflected in our forward looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Important factors that could cause our actual results to differ materially from the expectations reflected in the forward looking statements include, among others: the timing and extent of changes in prices of, and demand for, crude oil and condensate, natural gas liquids (“NGLs”), natural gas and related commodities; our ability to successfully execute our business and financial strategies; our ability to comply with the financial and other covenants in our debt instruments, to repay our debt, and to address our liquidity needs, particularly if oil and natural gas prices remain volatile and/or depressed; the extent to which we are able to engage in successful strategic alternatives to improve our balance sheet and satisfy our obligations under our debt instruments; the extent to which we are able to pursue drilling plans and acquisitions that are successful in maintaining and economically developing our acreage, producing and replacing reserves and achieving anticipated production levels; our ability to successfully integrate our various acquired assets into our operations and realize the benefits of those acquisitions to fully identify existing and potential issues or liabilities and to accurately estimate reserves, production and costs with respect to such assets; our ability to access the credit and capital markets to obtain financing on terms we deem acceptable, if at all, and to otherwise satisfy our capital expenditure, debt service and other funding requirements through internally generated cash flows, asset sales and other activities; the extent to which our listing on an over-the-counter securities exchange rather than a national securities exchange will impair our access to equity markets and ability to obtain financing; our ability to utilize the services, personnel and other assets of Sanchez Oil & Gas Corporation (“SOG”) pursuant to an existing services agreement; SOG’s ability to retain personnel and other resources to perform its obligations under that services agreement; the realized benefits of our partnerships and joint ventures, including our transactions with SNMP and our partnership with affiliates of Blackstone; the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may, therefore, be imprecise; the effectiveness of our internal control over financial reporting; the extent to which we can optimize reserve recovery and economically develop our properties utilizing horizontal and vertical drilling, advanced completion technologies, hydraulic stimulation and other techniques; the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities; our ability to successfully execute our hedging strategy and the resulting realized prices therefrom; the availability, creditworthiness and performance of our counterparties, including financial institutions, operating partners and other parties; the extent to which requests for credit assurances, or minimum volume commitments or “take-or-pay” obligations in excess of our oil and natural gas deliveries to, or transportation needs from, our contractual counterparties could have a material adverse effect on our business, financial condition and results of operations; competition in the oil and natural gas exploration and production industry generally and with respect to the marketing of crude oil, natural gas and NGLs, acquisition of leases and properties, attraction and retention of employees and other personnel, procurement of equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services; the extent to which our production, revenue and cash flow from operating activities are concentrated in a single geographic area; developments in oil producing and natural gas producing countries, the actions of the Organization of Petroleum Exporting Countries and other factors affecting the supply and pricing of oil and natural gas; the extent to which third-party operators operate our crude oil and natural gas properties successfully and economically; our ability to manage the financial risks where we share with more than one party the costs of drilling, equipping, completing and operating wells, including with respect to the assets acquired in the Comanche Acquisition (“Comanche Assets”); the use of competing energy sources, the development of alternative energy sources and potential economic implications and other effects therefrom; results of litigation filed against us or other legal proceedings or out-of-court contractual disputes to which we are party; the extent to which we incur uninsured losses and liabilities or losses and liabilities in excess of our insurance coverage, including losses related to sabotage, terrorism or other malicious intentional acts (including cyber-attacks) that disrupt operations; the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations, environmental laws and regulations relating to air emissions, waste disposal, hydraulic fracturing and access to and use of water, laws and regulations imposing conditions and restrictions on drilling and completion operations and laws, regulations, restrictions and guidelines with respect to derivatives, hedging activities and commercial lending standards; and the other factors described under “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the fiscal year ended December 31, 2018 and any updates to those factors set forth in our subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

In light of these risks, uncertainties and assumptions, the events anticipated by our forward-looking statements may not occur, and, if any of such events do, we may not have correctly anticipated the timing of their occurrence or the extent of their impact on our actual results. Accordingly, you should not place any undue reliance on any of our forward-looking statements. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Oil and Gas Reserves. The Securities and Exchange Commission (“SEC”) requires oil and gas companies, in their filings with the SEC, to disclose “proved oil and gas reserves” (i.e., quantities of oil and gas that are estimated with reasonable certainty to be economically producible) and permits oil and gas companies to disclose “probable reserves” (i.e., quantities of oil and gas that are as likely as not to be recovered) and “possible reserves” (i.e., additional quantities of oil and gas that might be recovered, but with a lower probability than probable reserves). We may use certain terms in this presentation, such as “resource potential” or “EURs” that the SEC’s guidelines strictly prohibit us from including in filings with the SEC. The calculation of resource potential, EURs and any other estimates of reserves and resources that are not proved, probable or possible reserves are not necessarily calculated in accordance with SEC guidelines. Investors are urged to consider closely the disclosure in our Annual Report on Form 10-K for the fiscal year ended December 31, 2018.

Non-GAAP Measures. Included in this presentation are certain non-GAAP financial measures as defined under SEC Regulation G. Investors are urged to consider closely the disclosure in our Annual Report on Form 10-K for the fiscal year ended December 31, 2018, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K and any reconciliation to GAAP measures provided in this presentation.



Management Representatives

Tony Sanchez, III

President and Chief Executive Officer

Cam George

Executive Vice President and Chief Financial Officer

Greg Kopel

Executive Vice President, General Counsel and Secretary



- I. Executive Summary**
- II. Asset Overview**
- III. Management Track Record**
- IV. Proposed Business Plan**
- V. Projections and Financial Highlights**

Appendices:

- A. Consolidated and UnSub Financial Projections**
- B. Corporate G&A Overview**
- C. Commodity Market Backdrop and Summary Capitalization**

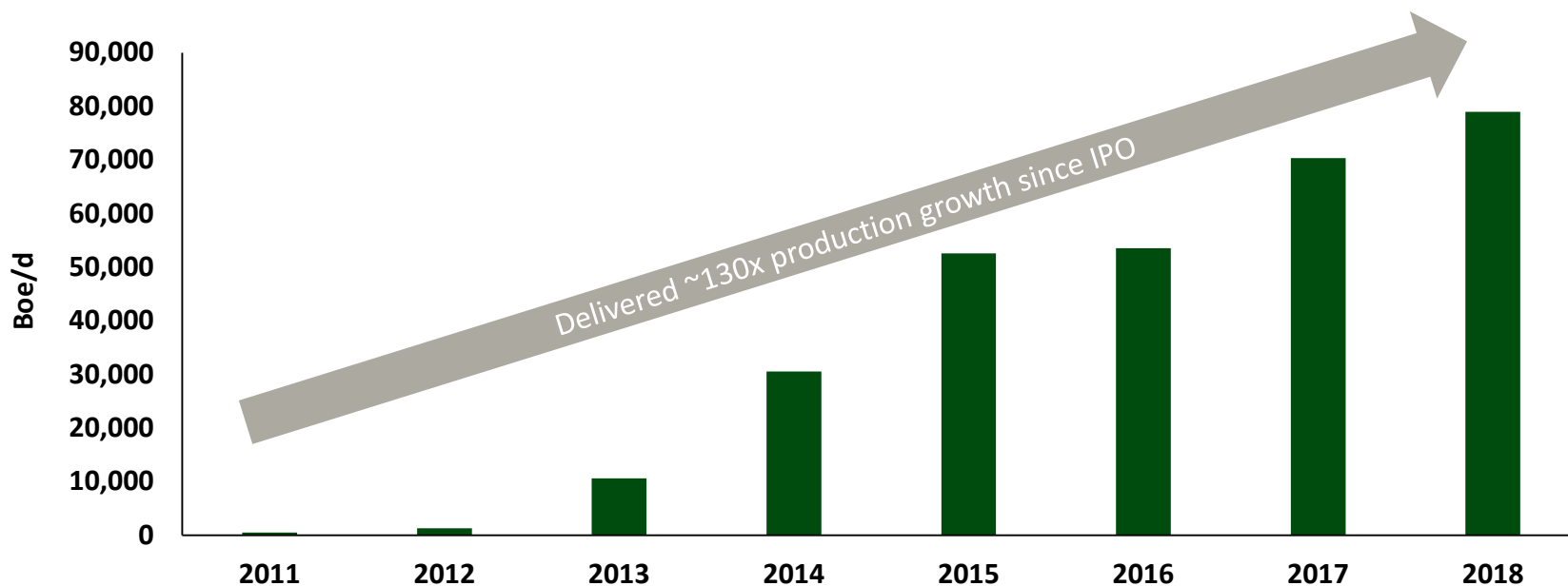


I. Executive Summary

Company History

Strong Track Record of Organic and Transactional Growth

STRICTLY CONFIDENTIAL – SUBJECT TO CONFIDENTIALITY AGREEMENTS – PRELIMINARY – SUBJECT TO SUBSTANTIAL REVISION



Completed IPO
at ~600 Boe/d

Capital budget reached \$250 MM

Achieved production of ~79 MBoe/d;
Surpassed \$1 billion in revenues

2011

2014

2016

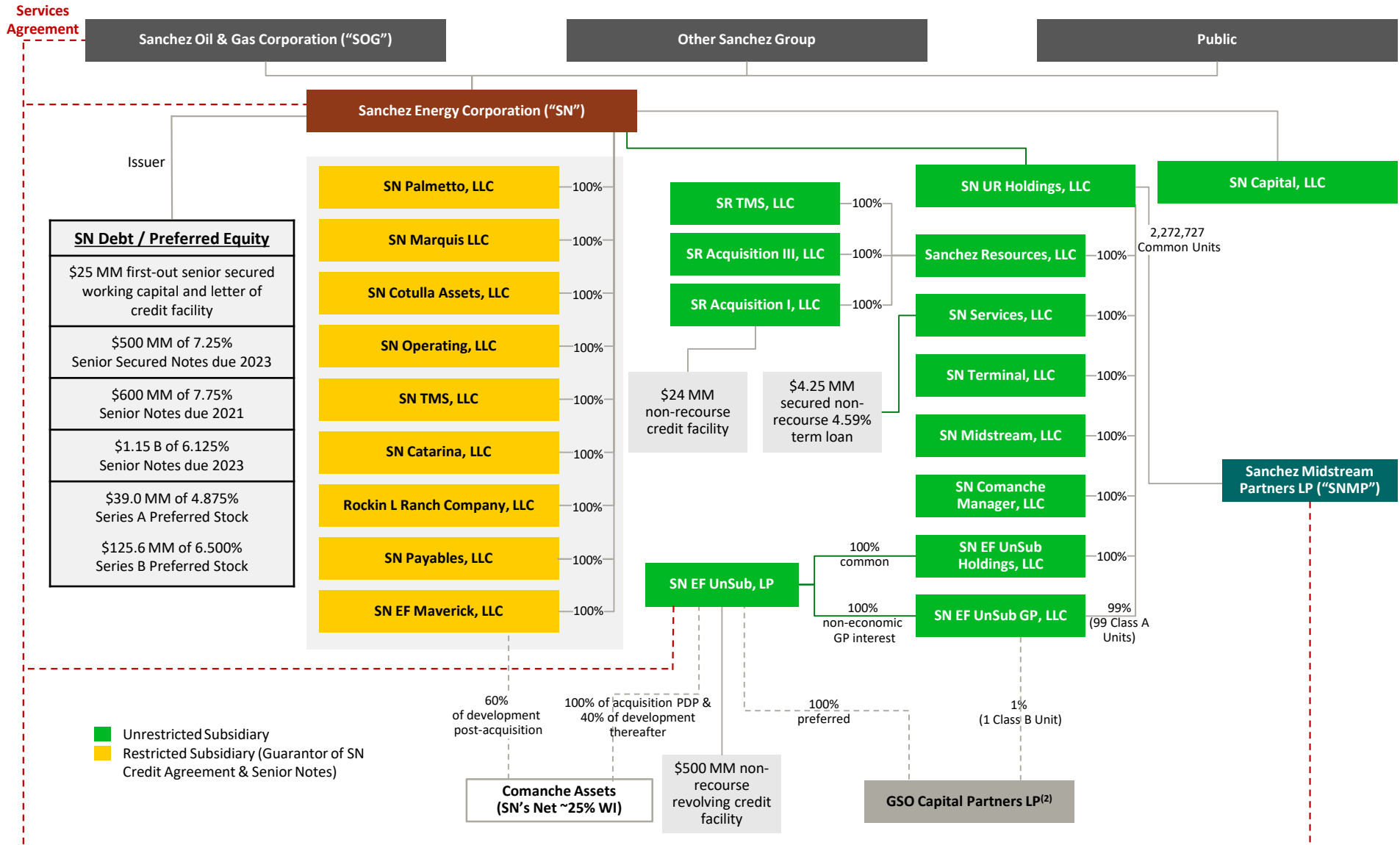
2017

2018

Acquired Catarina from Shell;
Doubled proved reserves

Completed ~\$2.3 billion Comanche acquisition:
155,000 acres, 67 MBoe/d and
300 MMBoe in proved reserves (with partner)

Organizational Structure

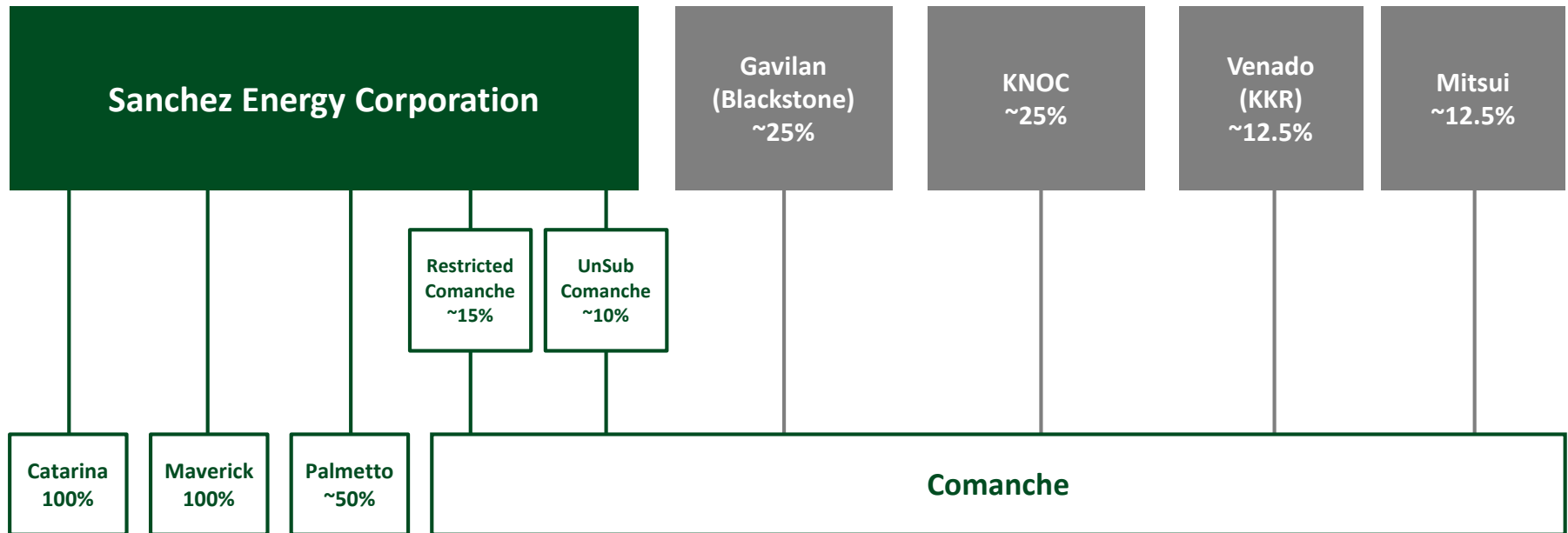


(1) As of 6/10/19.

(2) GSO ST Holdings Associates LLC owns the Class B Unit in SN EF UnSub GP, LLC, which holds the GP interest in SN EF UnSub, LP. GSO ST Holdings LP owns 485,000 preferred units in SN EF UnSub, LP, and the remaining 15,000 preferred units in SN EF UnSub, LP are held by Intrepid Private Equity Fund I, LP and Intrepid Private Equity SPV-A, L.P.



Summary Asset Ownership





Situation Overview



We have achieved tremendous growth through both organic development, as well as significant acquisition activity, and assembled a world-class asset in the Eagle Ford Shale

- ◆ Much of the transactional growth occurred in a higher commodity price environment

The commodity price downturn has caused us to re-evaluate our business strategy

- ◆ We have refocused the business plan to prioritize free cash flow generation over production growth through improved capital efficiency and significant operational and cost initiatives

We are seeking to proactively address our capital structure and liquidity constraints

- ◆ The oil / liquids price downturn in recent months has prompted us to enter into discussions with our stakeholders on a comprehensive recapitalization solution
- ◆ While we could pursue near-term liquidity-enhancing transactions to extend our runway, this strategy may not offer our stakeholders the same opportunity to fully participate in a commodity price recovery or enable our team to best optimize our large asset base

New capital is required to maximize the value of our assets

- ◆ Meaningful new investment will be necessary to enable the continued realization of significant benefits from the recent performance enhancement program we have executed

We have developed a high-graded business plan that offers asset stability and future free cash flow generation, with significant margin expansion from a commodity price recovery

- ◆ We have prepared a comprehensive business plan that incorporates the operational improvements, cost reduction efforts and other initiatives underway with the goal of creating a sustainable enterprise capable of consistently delivering free cash flow to stakeholders



Key Takeaways

Strategic, Highly Concentrated Eagle Ford Shale Position

- ◆ Dominant position of ~485,000 gross (~283,000 net) acres in the Eagle Ford Shale
- ◆ ~77% of our net acreage is held by production and continuous drilling obligations
- ◆ Integrated two major acquisitions (Catarina from Shell, and Comanche from Anadarko) which transformed the Company into one of the largest and most active operators in the basin

Decades of Lower Risk, Repeatable Drilling Inventory

- ◆ 2,000+ identified drilling locations in the development plan based on optimal well spacing
- ◆ Future upside from multiple benches in the Eagle Ford with 4,000+ potential drilling locations and additional opportunities from the Austin Chalk and Pearsall Shale

Recognized Low Cost Operator

- ◆ Historically recognized as one of the lowest cost operators in the Eagle Ford
- ◆ Rapidly improving cost structure through comprehensive and rigorous performance review
- ◆ Recently reduced corporate headcount by 20%-30% and achieved meaningful cost savings

Strong Management Track Record of Asset Optimization

- ◆ Management identified Catarina as an underperforming property with significant upside and quickly implemented a development program that optimized it into a crown jewel asset
- ◆ Conducted similar program at Comanche with positive and promising trajectory

Recent Operational Initiatives Already Producing Results

- ◆ Optimized completions, flowback strategy and spacing at Comanche in 2018
- ◆ Initiated aggressive frac interference mitigation program, coupled with workover and artificial lift enhancement, to maximize base PDP well performance
- ◆ Targeting lowest risk, highest return potential benches and retaining “science” benches in long-term inventory for future upside opportunities

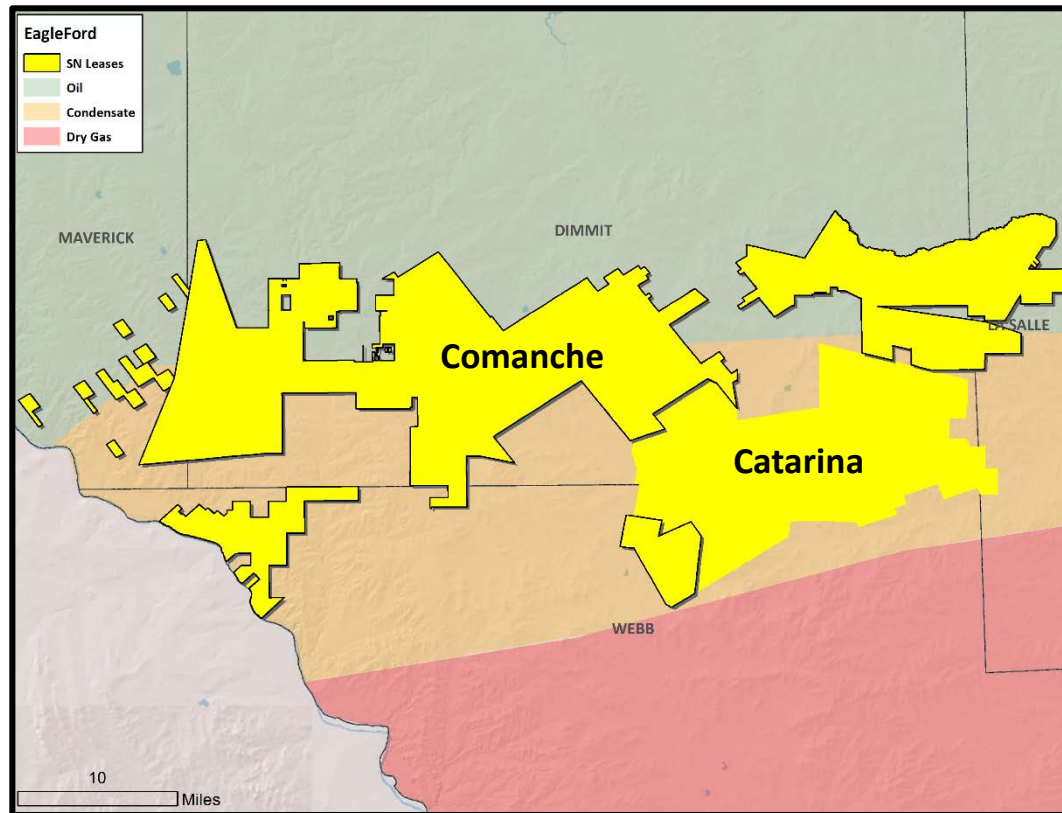


II. Asset Overview



Core Asset Overview

Sanchez Energy holds one of the largest contiguous acreage positions across any U.S. producing basin



Catarina

◆ Acquired from Shell (2014)

- ❖ Gross acres: ~106,000
- ❖ Net acres: ~106,000
- ❖ Total engineered Eagle Ford locations: ~510
- ❖ Total identified Eagle Ford locations: ~595
- ❖ Proved reserves: ~220 MMBoe
- ❖ SEC⁽¹⁾ PV-10: ~\$1.3 billion
- ❖ Current production: ~36 MBoe/d

Comanche

◆ Acquired from Anadarko (2017)

- ❖ Gross acres: ~318,000
- ❖ Net acres: ~77,500
- ❖ Total engineered Eagle Ford locations: ~845
- ❖ Total identified Eagle Ford locations: ~2,795
- ❖ Proved reserves: ~141 MMBoe
- ❖ SEC⁽¹⁾ PV-10: ~\$1.0 billion
- ❖ Current production: ~28 MBoe/d

(1) Price deck referenced in year-end 2018 Ryder Scott SEC reserve report was \$65.56 WTI and \$3.10 Henry Hub.

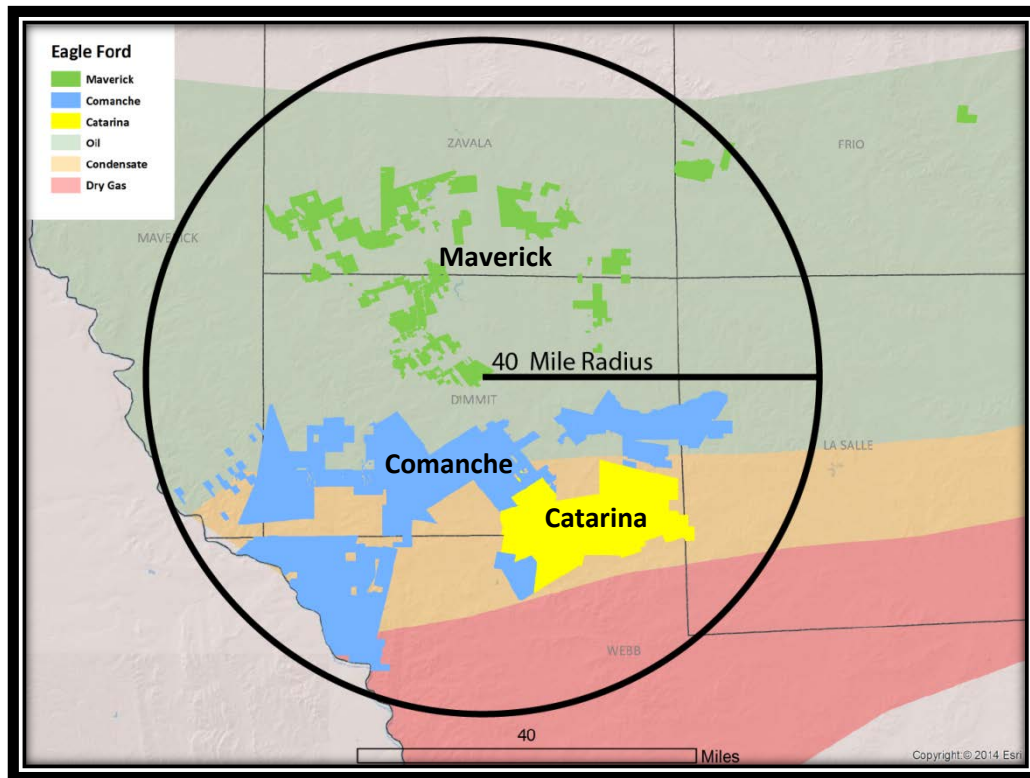


Strategically Concentrated Acreage Position

Core Acreage Position Within a ~40 Mile Radius Provides Unique Competitive Advantages

Large, concentrated asset base drives significant synergies of scale

- ◆ Cost savings from moving rigs and equipment
- ◆ Shared resources for in-field gathering, water transportation, etc.
- ◆ More efficient drilling process
- ◆ Substantial asset-level knowledge applied to neighboring acreage
- ◆ More efficient field-level operations
- ◆ Enhanced pricing from volume and location

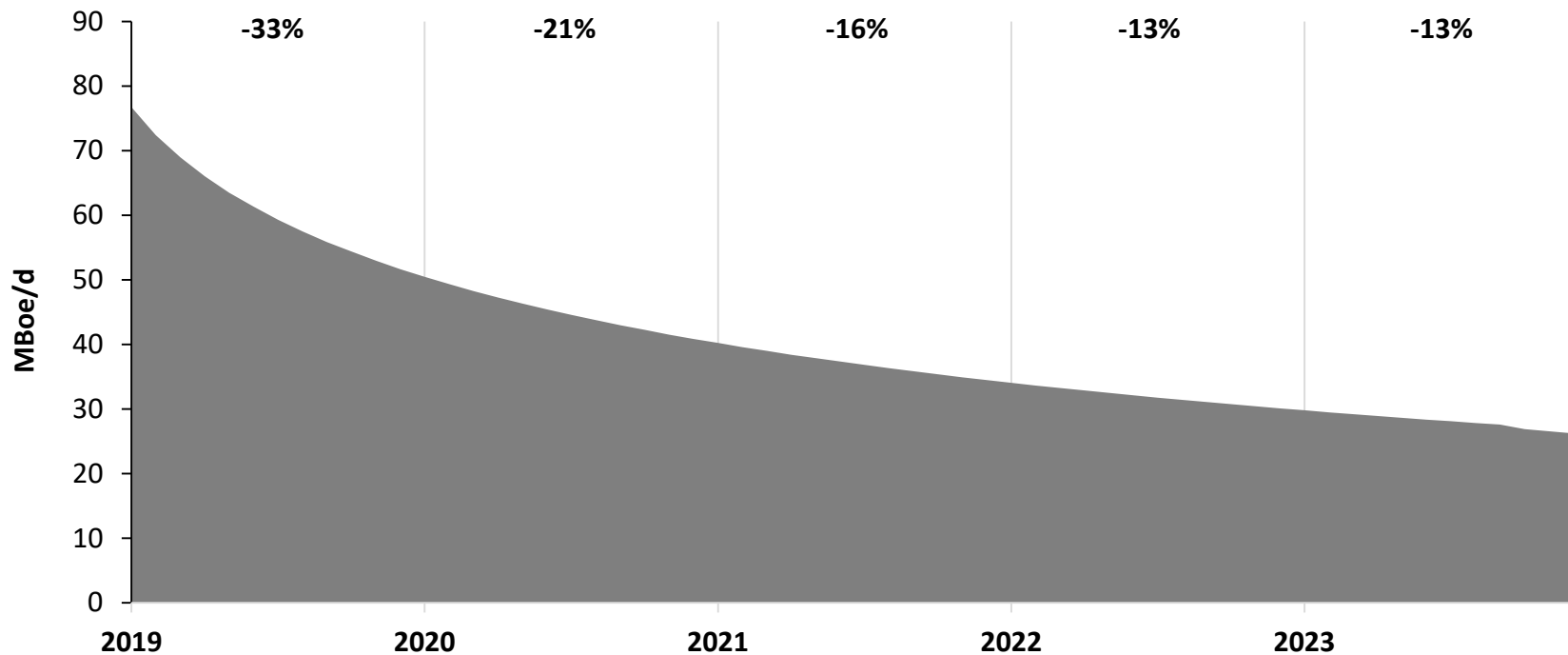




Stable Production Base Across 2,400+ Wells

- Sanchez Energy produces from a broad base of more than 2,400 wells across its asset portfolio⁽¹⁾
- Managing the business for a more stable production base reduces future maintenance capital requirements and helps position the Company for free cash flow and margin expansion in a higher commodity price environment
- Estimated 3-year base decline rate from 2020-2023 is less than 15%

Estimated PDP Production Profile⁽²⁾



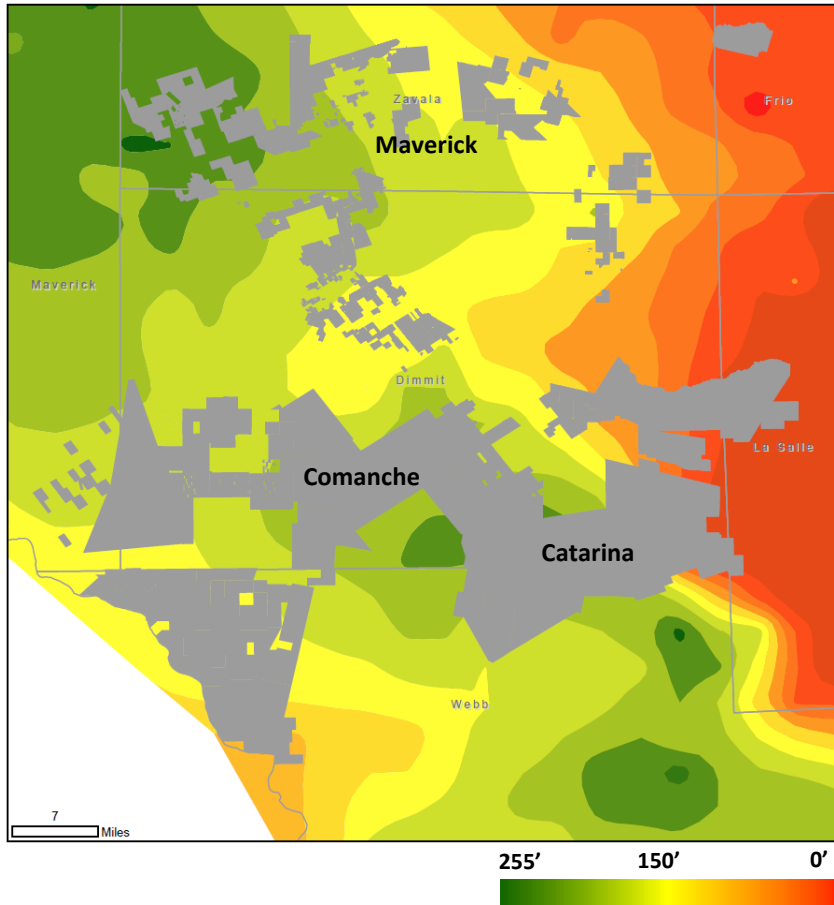
(1) Well count shown represents the estimated number of total wells across the portfolio, including any wells which may be offline from time to time, including for service, workover activities or in connection with comprehensive frac mitigation strategies.

(2) Reflects Consolidated production from year-end 2018 Ryder Scott SEC reserve report. Excludes all future development.



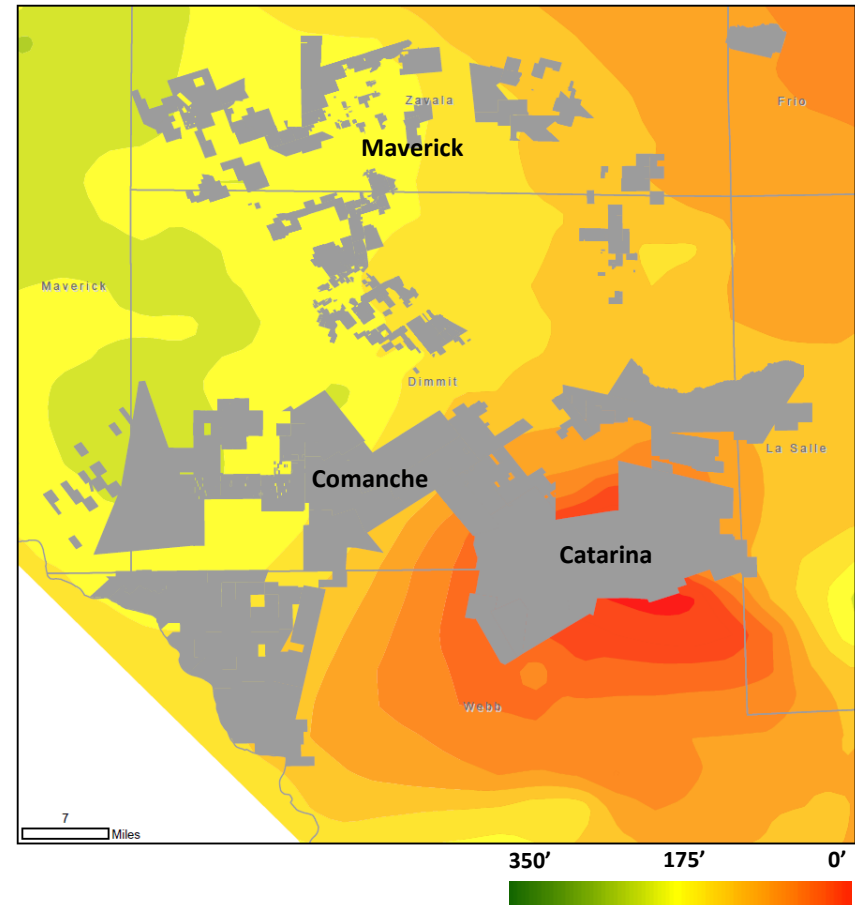
Well-Defined Geology with Repeatable Development Potential

Upper Eagle Ford Thickness



- ◆ Upper Eagle Ford is prominent throughout most of Catarina
- ◆ The Upper Eagle Ford fairway also extends into select areas of Comanche

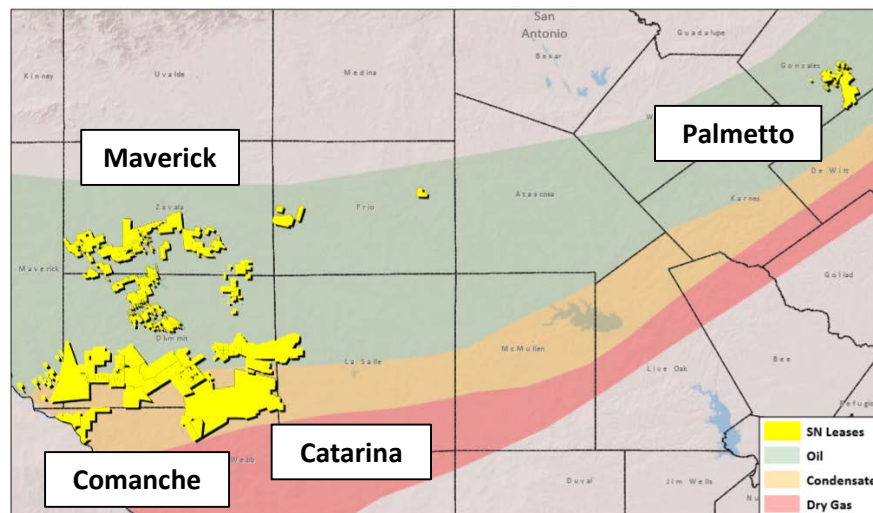
Lower Eagle Ford Thickness



- ◆ Lower Eagle Ford is prominent throughout most of Comanche
- ◆ The Lower Eagle Ford is the most proven and consistent zone throughout the entire play



Multi-Year Inventory of Organic Growth Opportunities



Area	Net Production ⁽¹⁾ (MBoe/d)	% Oil ⁽¹⁾	Producing Wells ⁽¹⁾	Est. Total Engineered Eagle Ford Locations ⁽²⁾	Est. Total Identified Eagle Ford Locations ⁽³⁾	Gross Well Commitment Per Year
Catarina	~36	25%	414	~510	~595	50
Comanche	28	37%	1,666	845 (125 net)	2,795 (420 net)	48 - 60
Maverick	3	97%	66	790	790	~3
Palmetto	2	74%	88	80 (40 net)	230 (115 net)	~10
Total	~69	35%	2,234	~2,225 (~1,465 net)	~4,410 (~1,920 net)	~111 - 123

(1) As of 6/11/19. Well count shown specifically represents the estimated number of producing wells online as of that date and excludes wells across the portfolio which were offline, including for service, workover activities or in connection with comprehensive frac mitigation strategies.

(2) At current assessment of optimized well spacing and targeting, net to Restricted Group.

(3) Total identified Eagle Ford locations, net to Restricted Group. Excludes potential opportunities associated with other prospective horizons, including the Austin Chalk and Pearsall Shale.



III. Management Track Record

Catarina Case Study

Strong Track Record of Value-Added Asset Optimization

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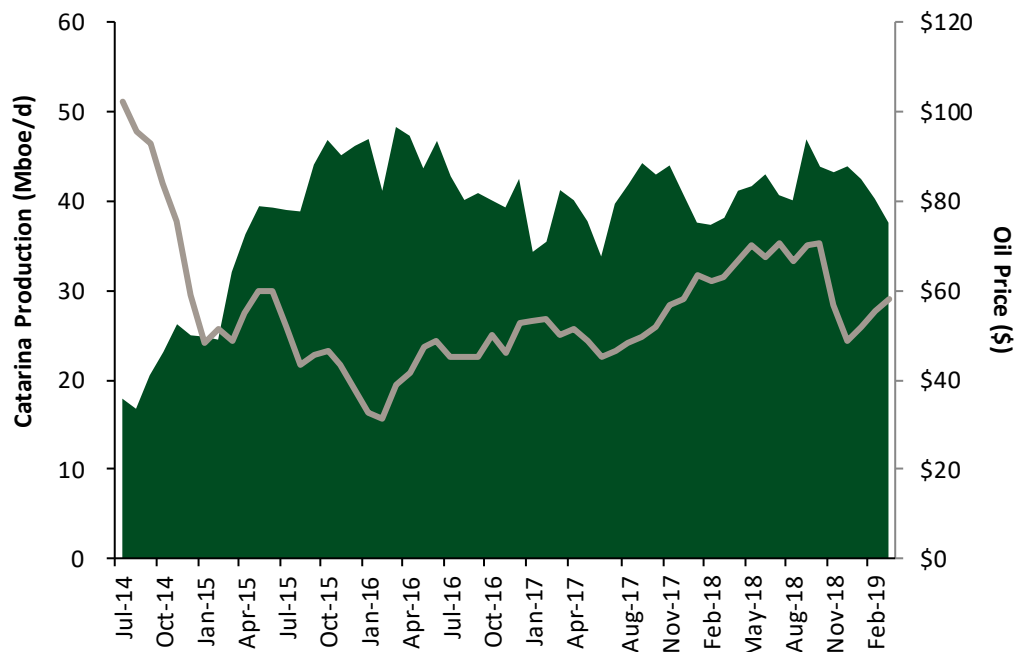


Management has demonstrated the ability to create substantial value and generate attractive returns, even in a declining commodity price environment

- ◆ Acquired from Shell in 2014
- ◆ Shortly after closing, oil prices plummeted from \$100+ to ~\$50 per Bbl
- ◆ However, we added significant value through capital investment and aggressive cost management
- ◆ Rapidly doubled production within the first year
- ◆ Divested midstream assets for ~\$350 million in 2015
- ◆ Significant upside inventory remains for commodity price recovery

Historical Cash Flow	
Purchase Price	(\$639)
Cumulative Cashflow	(\$189)
Catarina Midstream Transaction	\$345
Total	(\$483)

Asset Value	
PDP	\$729
PUD	\$605
Total Proved	\$1,334
Money Multiple	2.8x
Money Multiple on PDP	1.5x



Note: Reserve values from year-end 2018 Ryder Scott SEC reserve report.



Nimble and experienced management team has proven highly effective in quickly addressing operational issues with strong and clear results

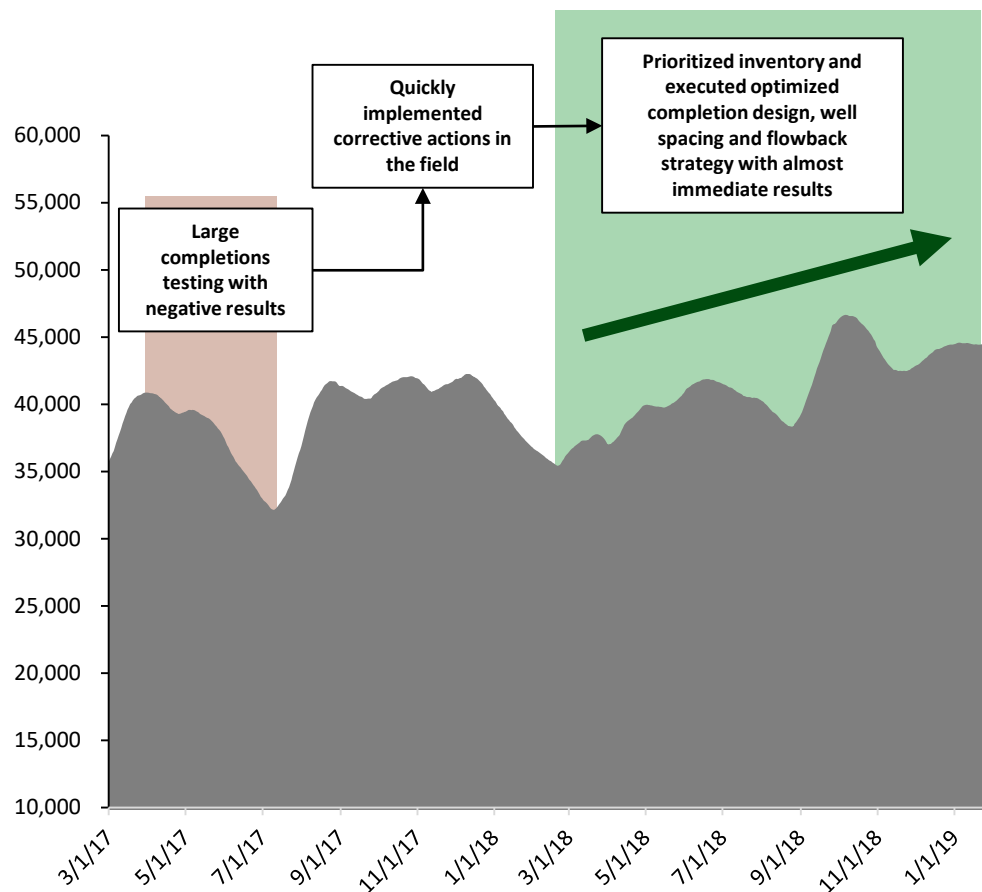
◆ Trial activity yielded unfavorable results

- Tested large completion designs, tight well spacing and aggressive flowback strategies
- Results were unfavorable, with performance ~20% below type curves

◆ Management took decisive action

- Adjusted rig schedule to prioritize highest return areas
- Shifted well spacing and completion design away from testing and into development with prudent, data-driven approach
- ***Strong and clear results: production has increased ~40% off the lows in Q2 2017***

◆ Current production has remained strong and responded well to low cost, low risk optimization projects begun in late 2018





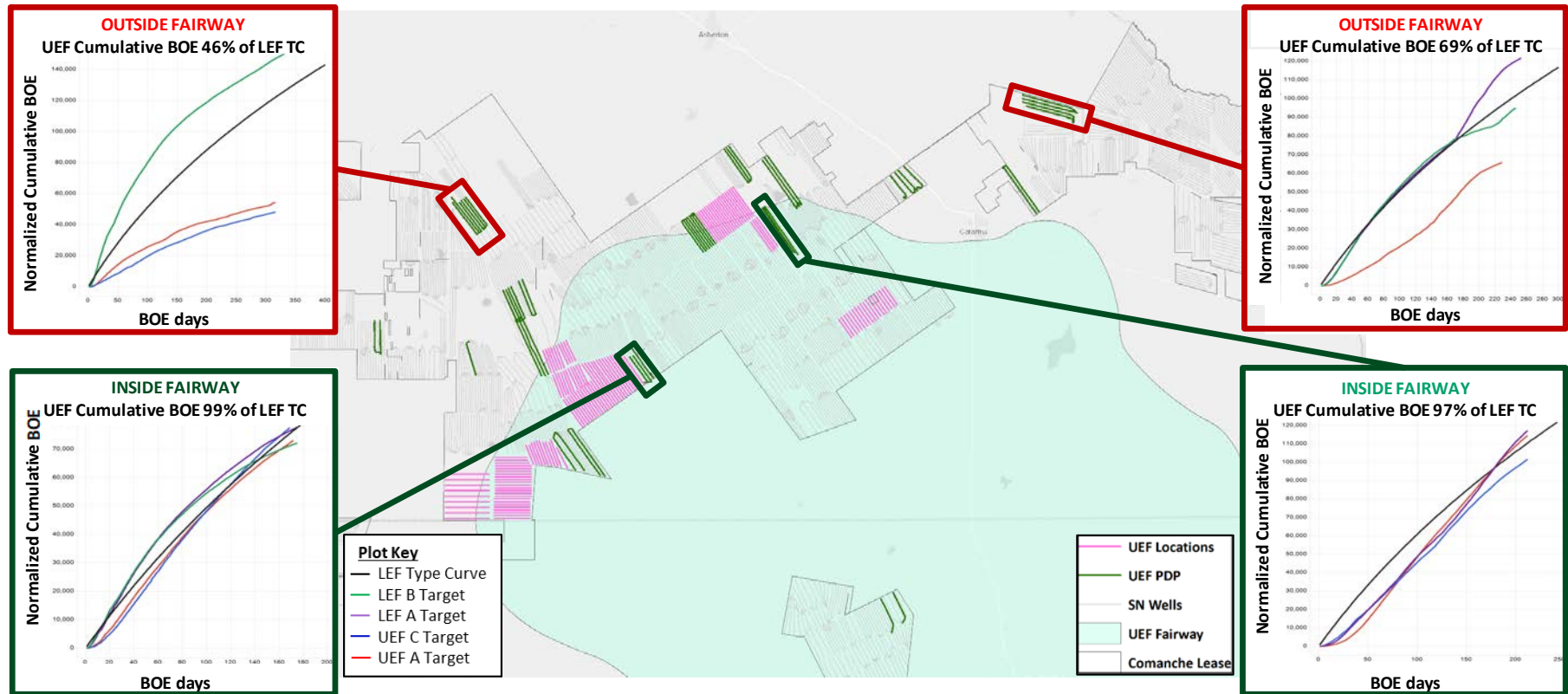
Lessons Learned and Proactive Operational Leadership

Initiative	Original Rationale	Outcome	Response Implemented
1. Upper Eagle Ford Well Performance	<ul style="list-style-type: none"> Based on proven success at Catarina Large step-out test driven by JDA partner 	<ul style="list-style-type: none"> Disappointing Upper Eagle Ford performance in the A and C benches in appraisal pads outside of the fairway 	<ul style="list-style-type: none"> Sanchez significantly reduced capital to the Upper Eagle Ford program and will non-consent any additional wells driven by partner outside of the fairway
2. Testing of Aggressive Flowback Strategy	<ul style="list-style-type: none"> Attempted to improve NPV and accelerate cash flow timing Successfully tested in areas with higher oil yields and better pressure 	<ul style="list-style-type: none"> Testing of various choke management strategies in late 2017 and early 2018 negatively impacted performance 	<ul style="list-style-type: none"> Sanchez determined conservative flowback strategy to be superior from IRR, EUR and NPV perspectives based on tests and is committed to executing strategy going forward
3. Completion Designs	<ul style="list-style-type: none"> Successful results from many industry leaders with significantly larger completions designs 	<ul style="list-style-type: none"> Tested a variety of completion designs in 2017 to determine optimal completions for Comanche (similar to post-acquisition Catarina growth strategy) 	<ul style="list-style-type: none"> Lower cost full slickwater design with ~1,700-2,000 lbs/ft demonstrating strong results Testing phase helped determine optimal go-forward design
4. Acquired DUC Spacing Too Tight	<ul style="list-style-type: none"> Even with observed underperformance, the economics were still attractive based on low cost of completing the drilled but uncompleted (“DUC”) wells 	<ul style="list-style-type: none"> Previous operator had spaced DUCs at ~450 ft. (132 wells at acquisition) Aggressive infill program drove spacing even tighter, leading to the underperformance 	<ul style="list-style-type: none"> Entire acquired DUC inventory has cycled through development program New wells will not be spaced closer than ~450 ft. where appropriate
5. Managing PDP Downtime (Frac Hit and Workovers)	<ul style="list-style-type: none"> Development schedule required significant new development activity near offset PDP wells 	<ul style="list-style-type: none"> Experienced an increase in downtime and lost production 	<ul style="list-style-type: none"> Began active workover program to stabilize PDP decline Adjusted 2019 development plan to reduce frac interference
6. Right-Sizing G&A Post Comanche Integration	<ul style="list-style-type: none"> Demonstrated efficient operator based on Catarina successes Implementing our proven strategies at Comanche 	<ul style="list-style-type: none"> Comanche was a transformative acquisition that quickly multiplied the size of the Company 	<ul style="list-style-type: none"> Recently reduced workforce by ~20%-30% Continue to evaluate and take action on additional cost-cutting measures throughout organization



Focusing Upper Eagle Ford Activity in the Fairway

Completed Appraisal Activity to Define Upper Eagle Ford Fairway



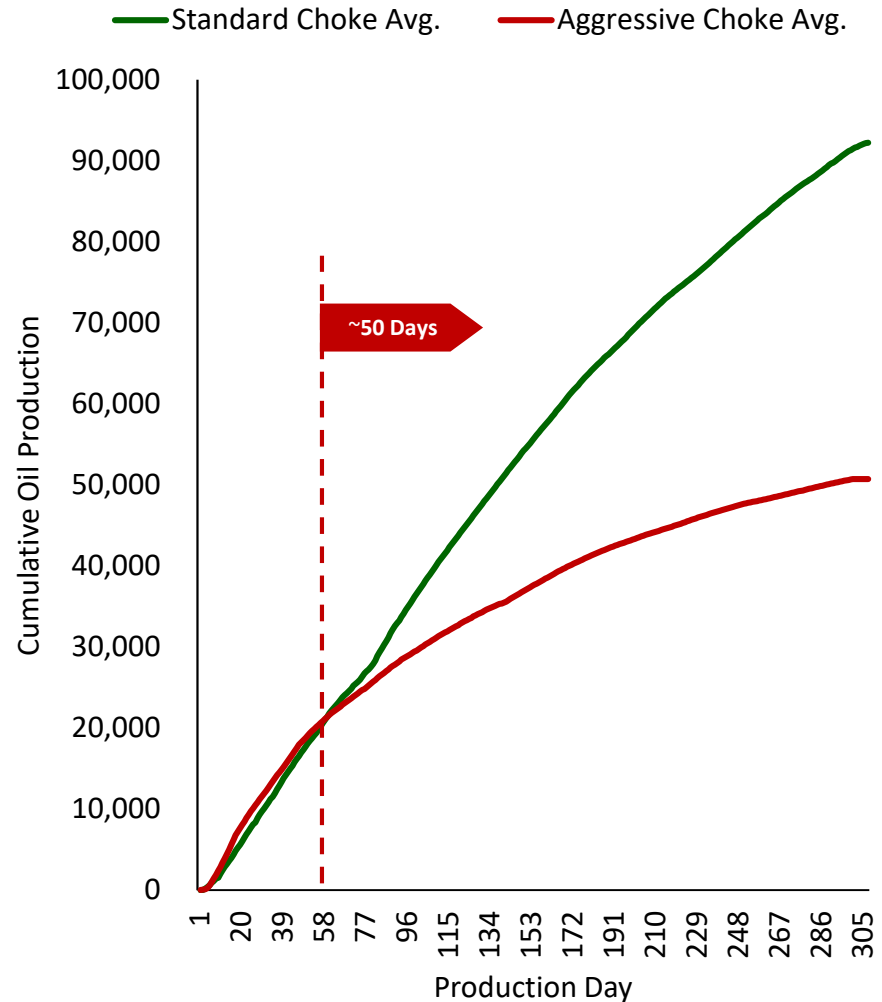
- ◆ Testing was driven by widespread success at Catarina and the potential to add material location counts and asset NAV
- ◆ Step-out appraisal testing continued under the Joint Development Agreement despite poor initial results
- ◆ Fairway delineation is based on correlation of reservoir quality and pressure to actual production data
- ◆ Sanchez does not plan to participate in Upper Eagle Ford tests outside of the fairway going forward
- ◆ ~130 Upper Eagle Ford engineered locations based on the delineated fairway



Returning to Conservative Flowback

Tested Flowback Strategies to Accelerate NPV

- ◆ Results do not support continued implementation of aggressive choke strategies across the asset base
- ◆ Oil decline on an aggressive choke strategy steepens after ~50 days, resulting in less revenue than the standard choke strategy
- ◆ Previous operator used a more conservative choke strategy, which targeted significantly reduced drawdown in comparison to aggressive testing
- ◆ Recent pivot back to a more conservative choke strategy has shown improved results
- ◆ Based on positive results, we believe managing drawdowns on reservoir pressure is the most beneficial flowback strategy



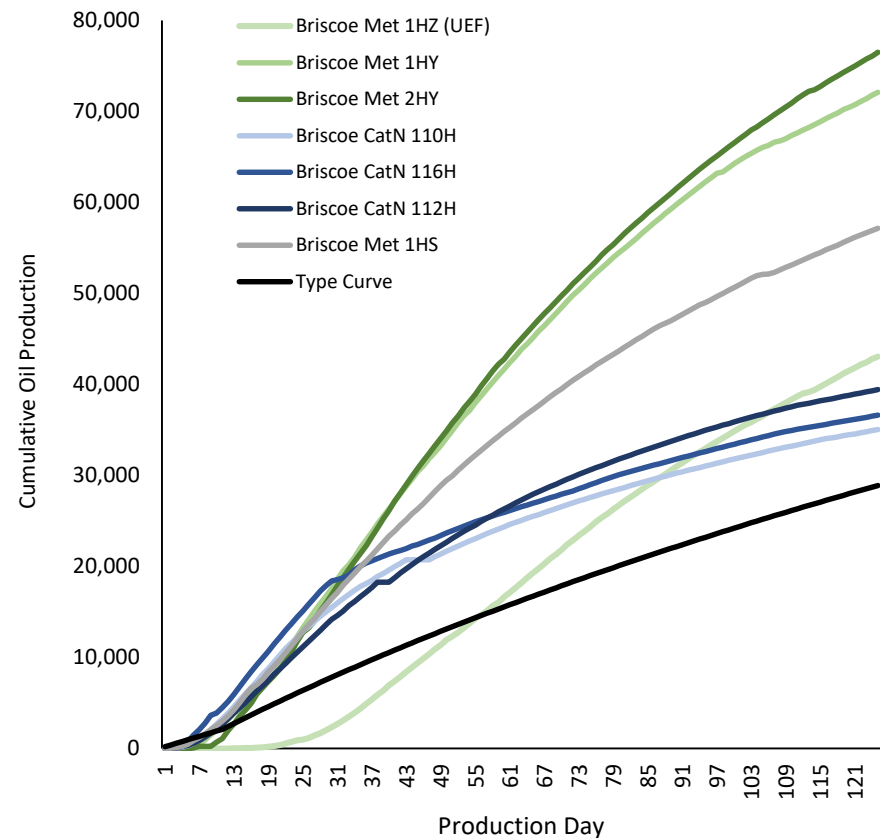


Testing Completion Design and Well Spacing Strategies

Extensively Tested Completion Designs Since Comanche Acquisition

Appropriate completion design at appropriate well spacing is critically important

- ◆ Comanche is a geologically complex asset that requires individual development strategies
- ◆ We now have the data to analyze the optimal combination of completion size and well spacing
- ◆ The graph depicts several recent wells from the Briscoe Metcalf and Briscoe Catarina North pads, which were completed with 2,000-2,600 lbs/ft and 50-60 bbls/ft
- ◆ Early results show success when applying this completion design with the appropriate well spacing

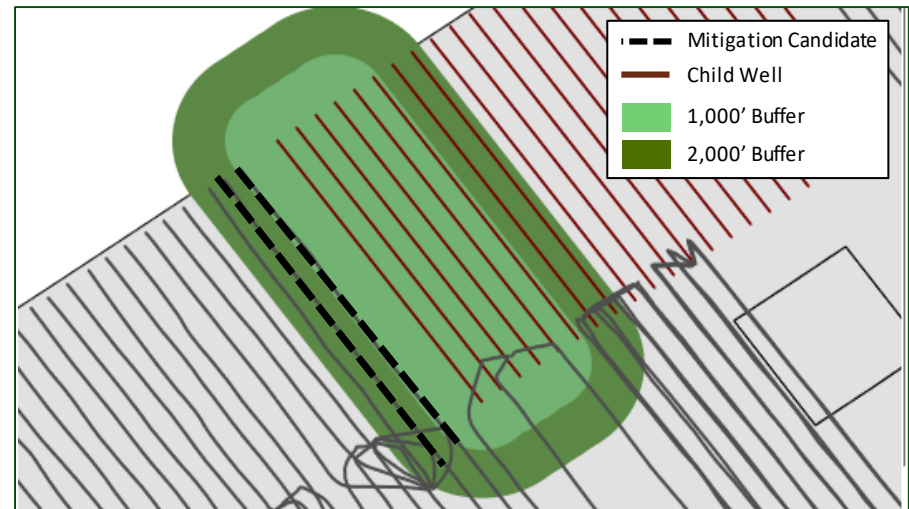
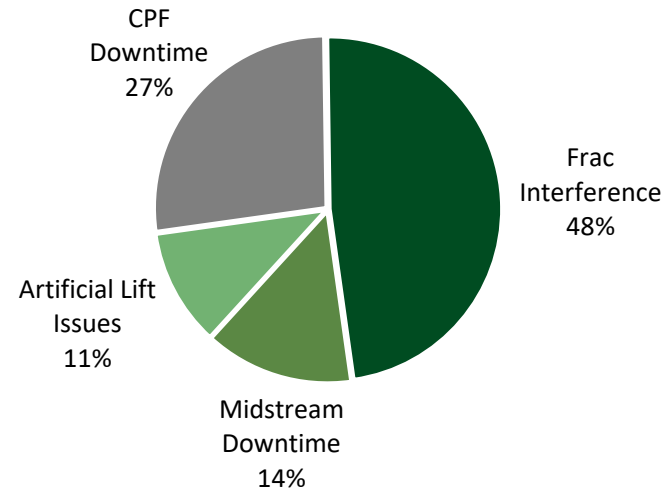




Focusing on Frac Mitigation to Protect Existing Production

Implementing Highly Promising Frac Mitigation Strategy

- ◆ Frac interference contributed to nearly half of the PDP underperformance
- ◆ We have established a more extensive shut-in program when completing offset wells
- ◆ Testing frac interference mitigation techniques across our asset base with promising results
- ◆ Future development plan has been designed to limit drilling near high value production
- ◆ New wells planned with minimum 1,000 ft. spacing from PDP wells





Prioritizing Workover and Artificial Lift Program

Rod Pump to Gas Lift

~80 Wells Targeted

- ◆ Reduce lift point and EOT by ~800 ft. TVD
- ◆ Reduce operating costs
- ◆ Reduce failure frequency

Plunger to Gas Lift

~60 Wells Targeted

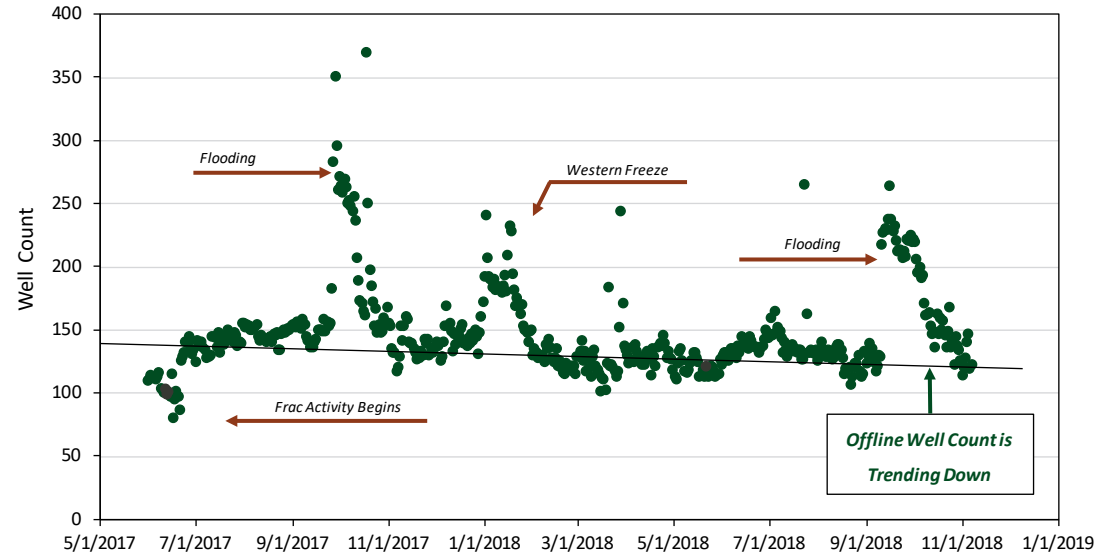
- ◆ Reduce lift point and EOT by ~800 ft. TVD
- ◆ Focus on wells where plunger is not the optimal lift method
- ◆ Reduce swabbing and have steadier production

Gas Lift Redesign

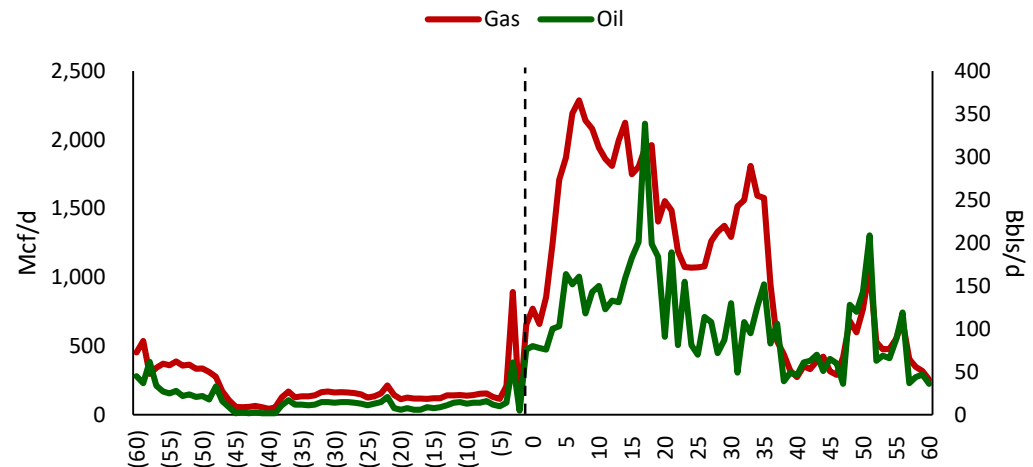
~270 Wells Targeted

- ◆ Reduce EOT by ~800 ft. TVD
- ◆ Lower orifice valve to have deeper point of injection
- ◆ Significantly increases chance that well will be lifting at the deepest point post-kickoff, as casing pressure drops and well unloads

Well Uptime Continues to Improve



Attractive Gas Lift Redesign Results

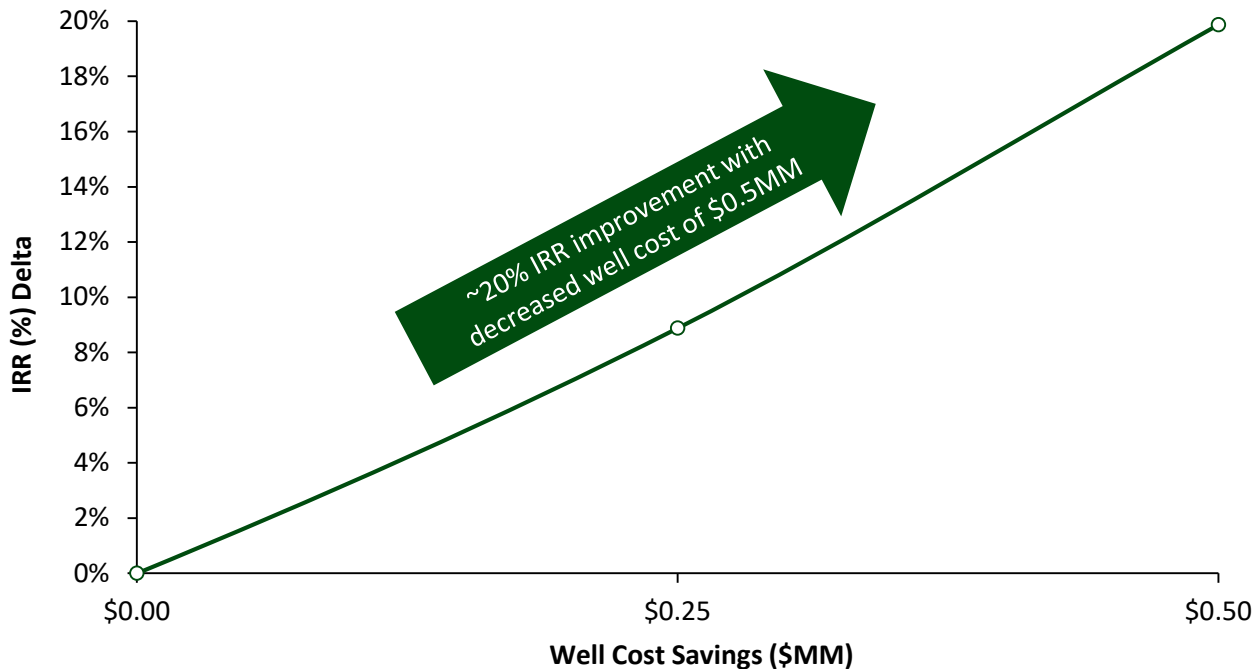




Aggressive Cost Management Drives Value

- ◆ Sanchez has been recognized as one of the lowest cost operators in the Eagle Ford
- ◆ During the commodity downturn, we earned a strong reputation by achieving industry-leading drilling and completion costs
- ◆ We are once again focused on generating value through safe, low cost operations
 - ❖ Rigorous negotiations with service providers
 - ❖ De-bundled approach when contracting for drilling and completion services
 - ❖ Optimized processes and designs to ensure more efficient field operations

Relentless Focus on Driving Value Through Efficient Operations

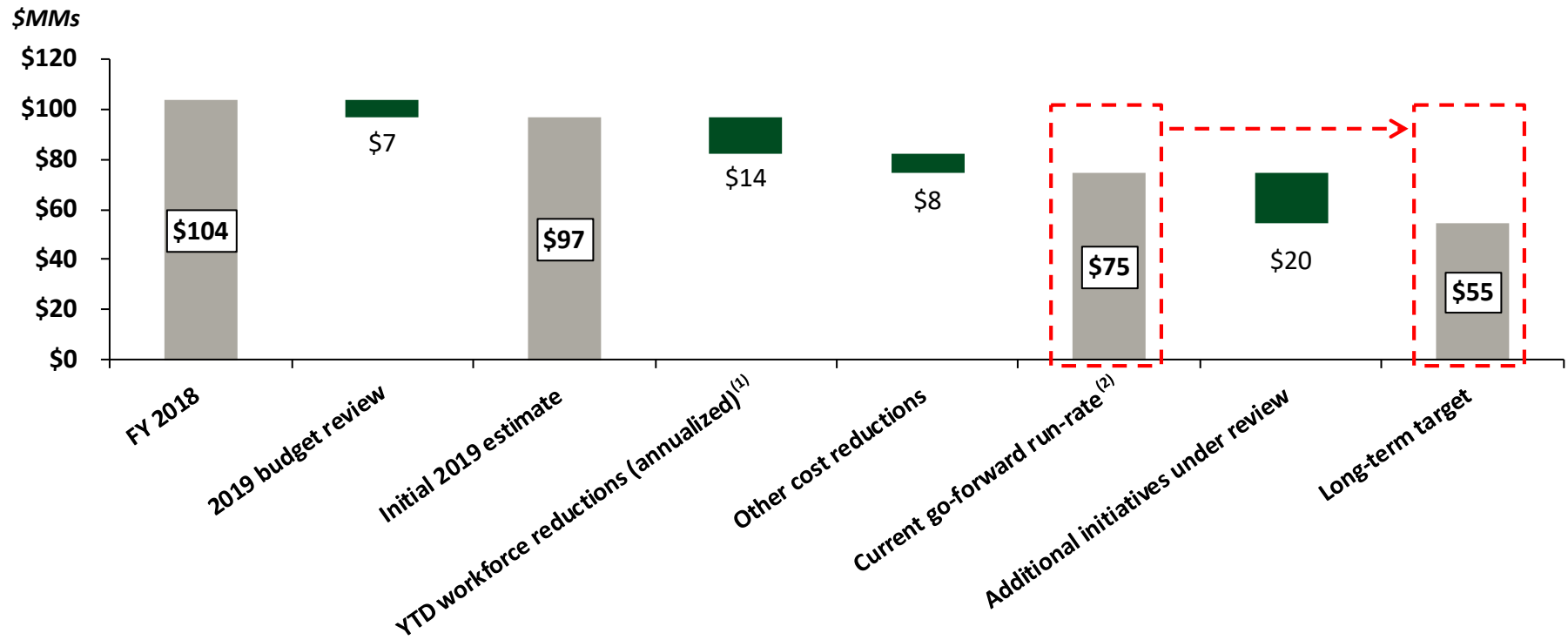




Clear Path to Achieving G&A Target

Management has already made substantial progress toward achieving our long-term G&A target

- ◆ We have already reduced our corporate overhead costs by nearly 30% from 2018 levels (~\$29 MM)
- ◆ Management has identified an additional ~\$20 MM in savings that are being actively pursued



Note: Figures shown on a consolidated basis.

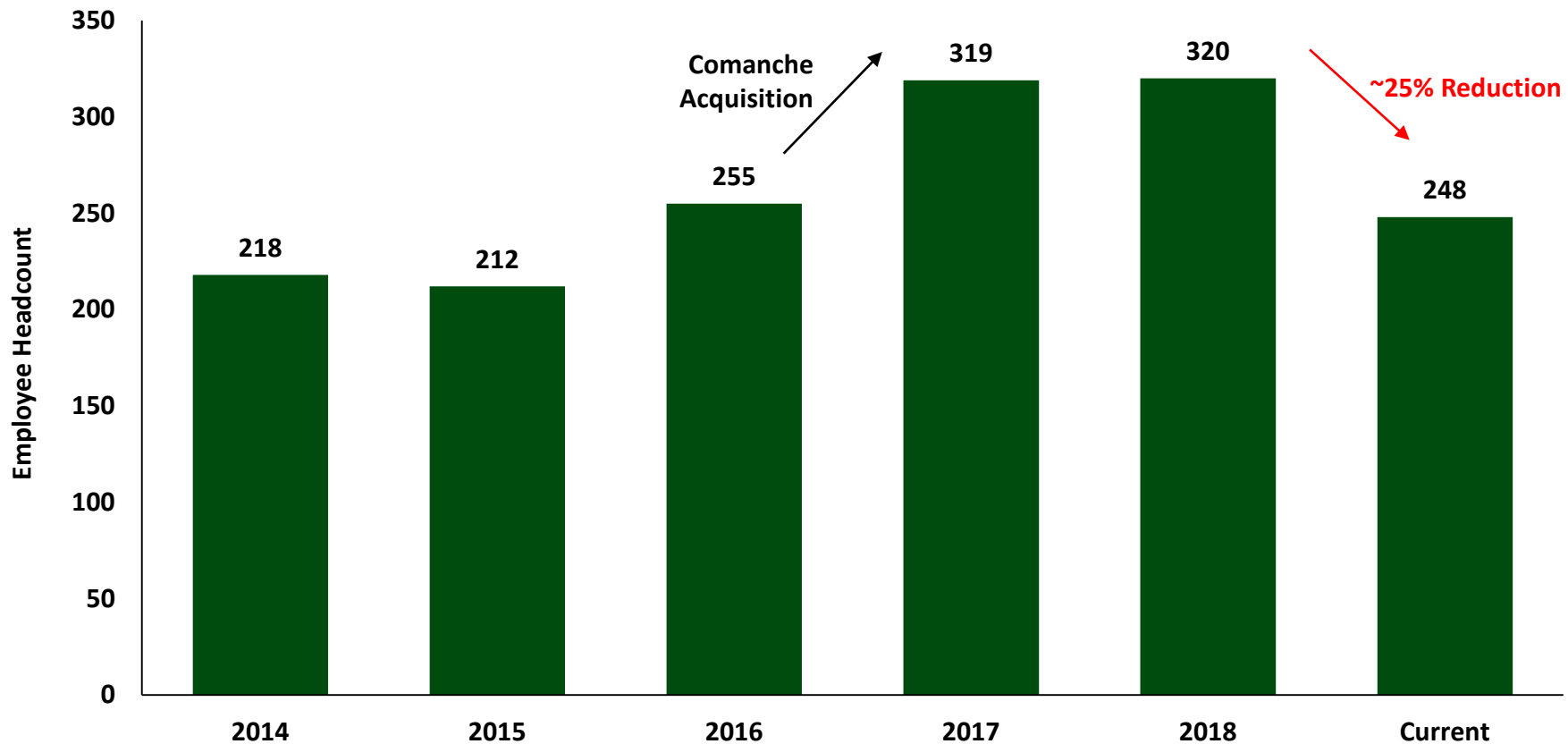
(1) Excludes one-time employee severance payments.

(2) Excludes incremental costs associated with executive and employee incentive/retention programs for 2019.



Actively Right-Sizing the Organization and Cost Structure

- ◆ Cumulative management efforts to-date have reduced employee headcount to pre-Comanche levels, while the Company retains full benefit of production and cash flow from the acquired properties
- ◆ We are committed to further streamlining our cost structure to best position Sanchez for the future



Note: Headcount illustration represents all employees of SOG for the periods shown.



IV. Proposed Business Plan



Core Objectives

Sanchez Energy is committed to developing and implementing a sustainable business model that meets the following core planning objectives:

- ◆ **Minimize external funding needs while still growing production**
- ◆ **Create path toward positive free cash flow at current commodity prices**
- ◆ **Continue to aggressively reduce corporate overhead costs**
- ◆ **Offer attractive investment opportunity with significant upside exposure to oil prices**
- ◆ **Retain and enhance core competencies and competitive advantages**
- ◆ **Maintain operational and financial resilience through future commodity cycles**



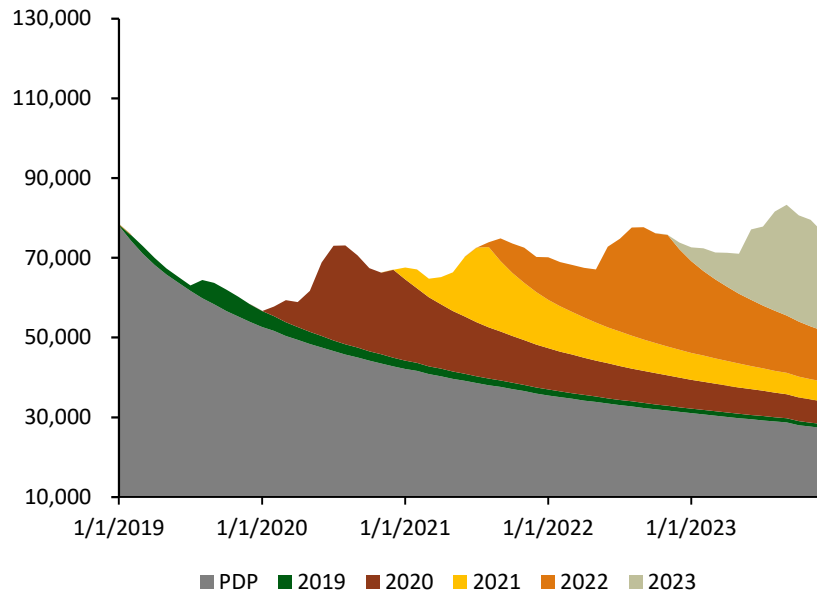
Unique Asset Base Provides High Degree of Capital Flexibility

Path 1: Maximize Cash Flow

	2019	2020	2021	2022	2023	5-Year Total
Avg. Production (MBoe/d)	64.9	63.2	68.8	72.7	77.3	69.4
Capital (\$MM)	\$110	\$317	\$311	\$313	\$299	\$1,348

EBITDA (\$MM)	\$262	\$263	\$302	\$334	\$346	\$1,508
EBITDA less Capital (\$MM)	\$152	(\$53)	(\$9)	\$22	\$48	\$159
Reinvestment Ratio	42%	120%	103%	94%	86%	89%

Production Profile with Annual Development Wedges (Boe/d)

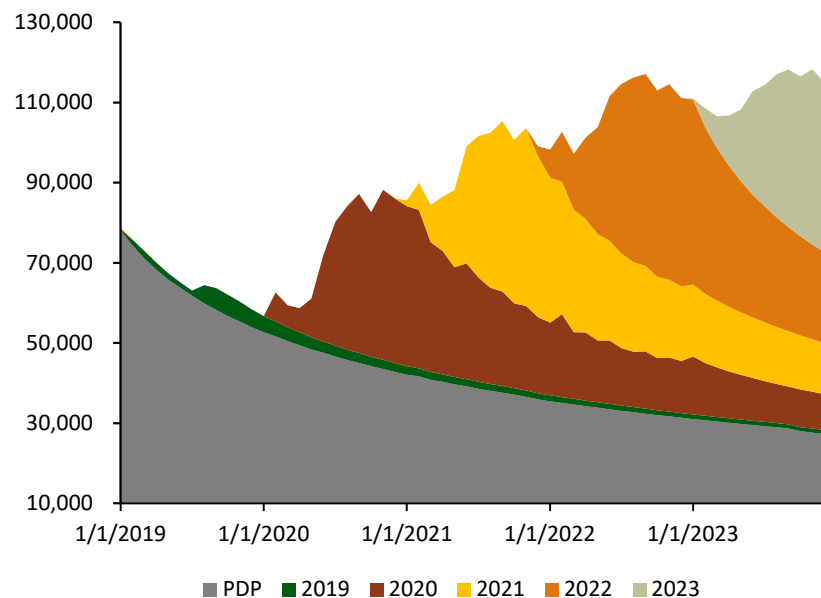


Path 2: Maximize Production Growth

	2019	2020	2021	2022	2023	5-Year Total
Avg. Production (MBoe/d)	64.9	73.3	95.5	108.5	112.8	91.0
Capital (\$MM)	\$110	\$564	\$566	\$558	\$566	\$2,363

EBITDA (\$MM)	\$262	\$278	\$423	\$472	\$511	\$1,947
EBITDA less Capital (\$MM)	\$152	(\$286)	(\$142)	(\$86)	(\$55)	(\$417)
Reinvestment Ratio	42%	203%	134%	118%	111%	121%

Production Profile with Annual Development Wedges (Boe/d)



Note: Reinvestment Ratio defined as capital / EBITDA. Strip pricing sourced from Bloomberg as of 6/27/19. Cases shown are illustrative, on a consolidated basis, and have been prepared using certain key assumptions.



Reinvestment Ratio Analysis – Oil Price Sensitivities

- ◆ Path 1: Maximize Cash Flow
- ◆ Efficient business plan drives significant potential margin expansion with modest price recovery

	2019	2020	2021	2022	2023	5-Year
Production (MBoe/d)	64.9	63.2	68.8	72.7	77.3	69.4
Capital (\$MM)	\$110	\$317	\$311	\$313	\$299	\$1,348

\$50	EBITDA	\$253	\$227	\$265	\$298	\$306	\$1,349
	EBITDA less Capital	\$143	(\$89)	(\$46)	(\$15)	\$8	\$1
	Reinvestment Ratio	43%	139%	117%	105%	97%	100%
\$60	EBITDA	\$273	\$287	\$341	\$380	\$389	\$1,669
	EBITDA less Capital	\$163	(\$30)	\$30	\$67	\$90	\$321
	Reinvestment Ratio	40%	110%	91%	82%	77%	81%
\$70	EBITDA	\$293	\$346	\$416	\$461	\$471	\$1,989
	EBITDA less Capital	\$184	\$30	\$105	\$149	\$173	\$641
	Reinvestment Ratio	37%	91%	75%	68%	63%	68%
\$80	EBITDA	\$314	\$406	\$492	\$543	\$554	\$2,309
	EBITDA less Capital	\$204	\$89	\$181	\$231	\$255	\$960
	Reinvestment Ratio	35%	78%	63%	58%	54%	58%

Note: Figures shown on a consolidated basis.

(1) Reinvestment Ratio defined as capital / EBITDA.

(2) Assumes gas price of \$2.75/MMBtu and NGL (Mt. Belvieu propane) price of \$24.00/Bbl.



V. Projections and Financial Highlights



Business Plan Assumptions (SN Consolidated)

Pricing (As of 6/27/19)

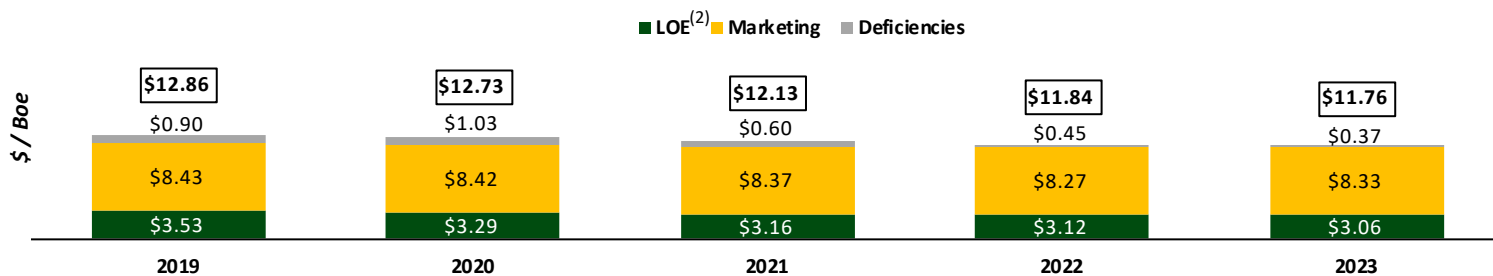
Base Case - Strip	2019	2020	2021	2022	2023
WTI Oil (\$/Bbl)	\$59.33	\$57.10	\$54.88	\$54.16	\$54.22
Henry Hub Gas (\$/MMBtu)	\$2.37	\$2.55	\$2.60	\$2.63	\$2.70

Commodity Price Realizations

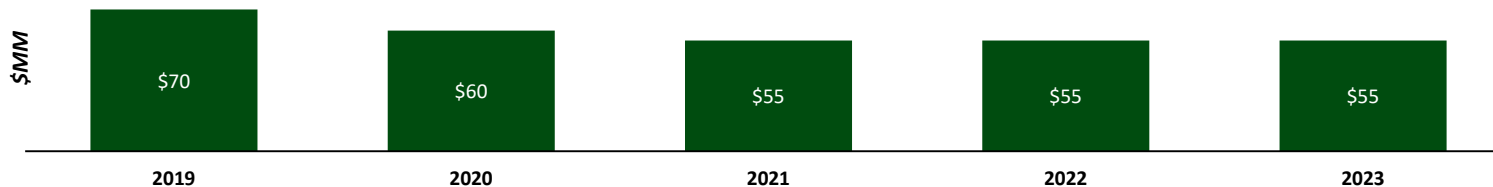
◆ Differentials have been developed by asset area based on historical 12-month average as compared to current futures pricing.

Realizations	Catarina	Comanche	Maverick	Palmetto	OBO	SR	TMS
Oil (% WTI)	101%	99%	105%	102%	104%	106%	103%
Gas (% Henry Hub)	103%	104%	101%	102%	62%	-	-
NGL (% WTI) ⁽¹⁾	24%	25%	27%	27%	27%	-	-

Lease Operating Expense



G&A



Note: Strip pricing sourced from Bloomberg as of 6/27/19.

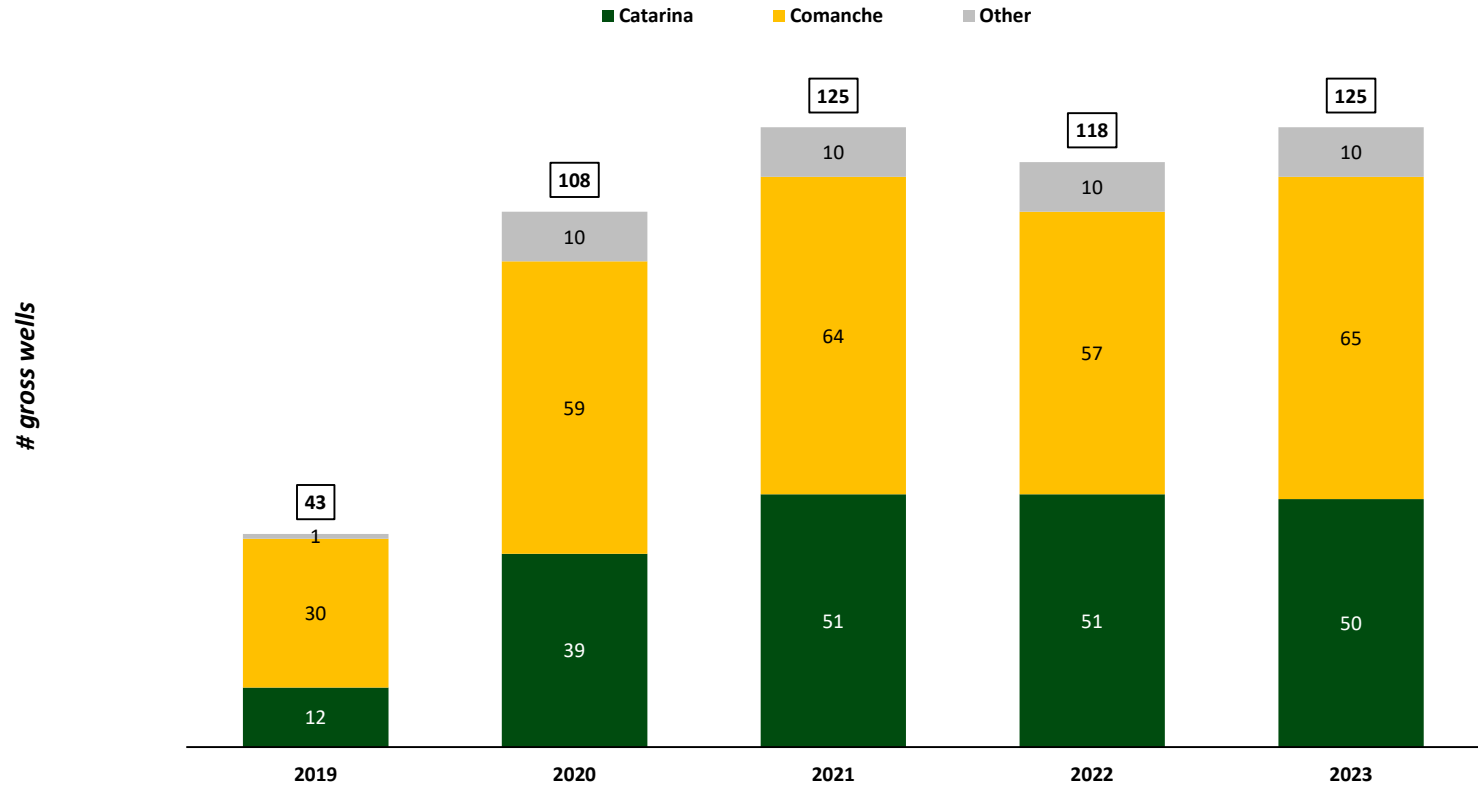
(1) SN Catarina and Comanche marketed NGL product components have averaged approximately 53% ethane, 26% propane, 15% butanes and 6% pentane in recent months under current plant environments. Basket components may change depending upon future gas quality, plant operations and recovery strategies.

(2) Includes water transfer via SNMP at Catarina.



Business Plan Assumptions (SN Consolidated)

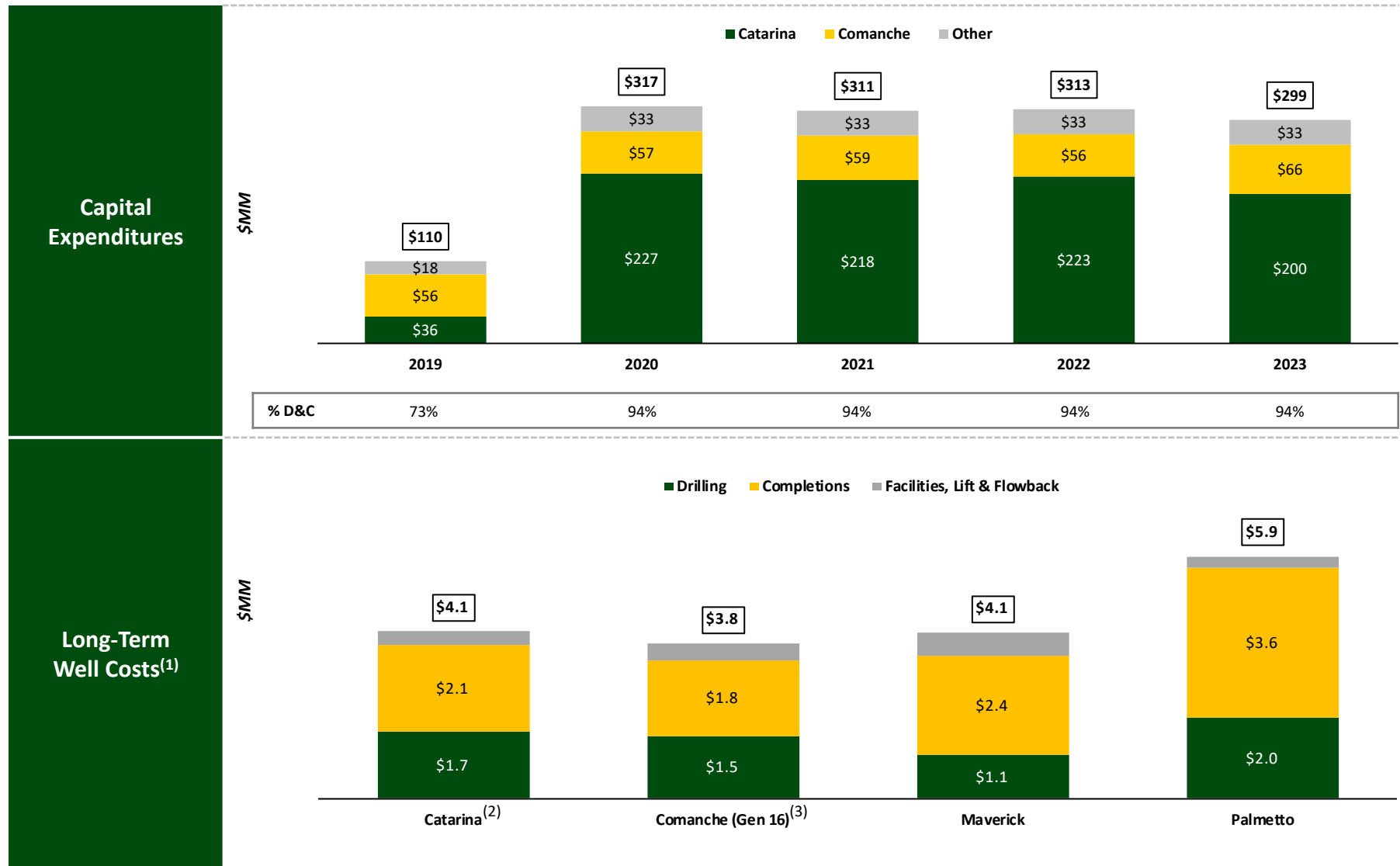
Drilling Activity



Gross Wells	43	108	125	118	125
Net (Restricted)	17	53	66	65	65
Net (UnSub)	3	6	6	6	7



Business Plan Assumptions (SN Consolidated)



(1) Assumed long-term well costs based on 2018 average well cost adjusted for 2019 average development lateral length. 2018 average vs. 2019 projected lateral lengths:

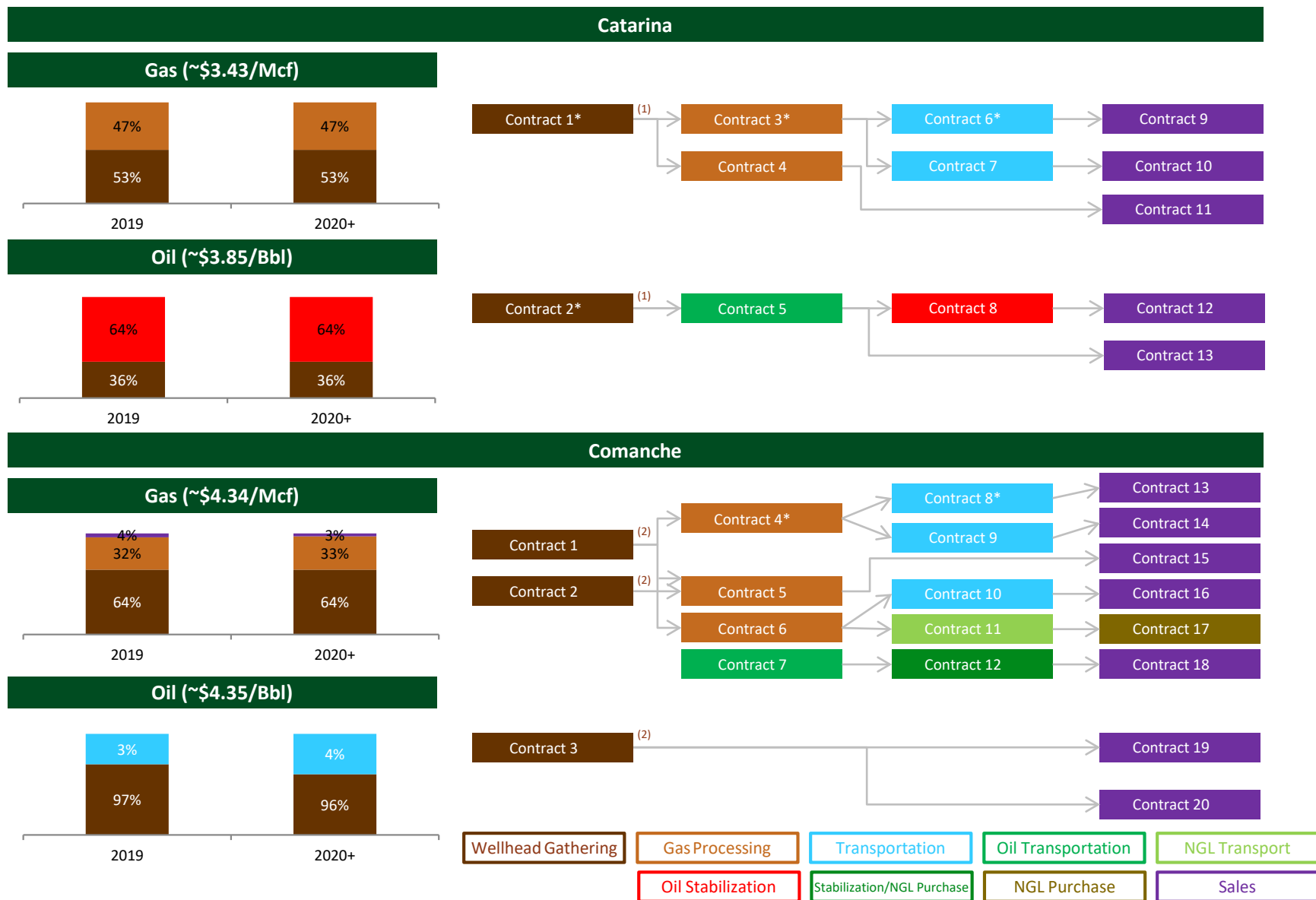
Catarina (~7,500 ft. vs. ~5,800 ft.), Comanche (~7,800 ft. vs. ~5,800 ft.) and Maverick (~10,200 ft. vs. ~5,700 ft.).

(2) AFE-based pricing of ~\$4.1 million per well in Q1 2020+; ~\$4.4 million for remainder of FY 2019.

(3) AFE-based pricing of ~\$3.8 million per well in Q3 2020+; ~\$4.5 million for remainder of FY 2019.



Illustrative Marketing Diagrams and Cost Overview



Note: Oil rates should be applied to net oil volumes. Gas rates should be applied to net dry gas volumes.

(1) Interruptible contracts and rates which can change upon notification from counterparty.

(2) Adjusted annually based on a cost of service model to achieve a certain rate of return.

* Denotes contracts that SNMP is a party to directly or through a joint venture.



Reconciliation of YE 2018 SEC Proved Reserves to 3P Management Case

- ◆ We have prepared a 3P database which reflects the key assumptions presented in the proposed business plan
- ◆ The below illustration describes the material reconciling items between this internally prepared 3P database and the Company's third-party year-end 2018 SEC reserve report (Restricted Group only)
- ◆ The estimated adjustments and 3P value shown may not be indicative of amounts which could be derived using other key assumptions, such as a different pace of capital activity or higher or lower commodity prices



Note: This illustrative waterfall was prepared according to a specific sequence which is important to understand. (1) The material inputs (e.g., price and expense profile) from the YE 2018 Ryder Scott SEC reserve report were incorporated into the 3P management case database, which reflects the key assumptions presented herein regarding the proposed business plan. (2) Individually and on a cumulative basis, adjustments were made for each of the categories shown in the illustration in the following order: (a) application of a 2% production risking based on estimated frac interference and downtime assumptions, (b) adjustment for the effective date of the database, from YE 2018 to the present date, (c) LOE and expense profile changes based on recent trends, (d) increase in realized and estimated marketing rates during YTD 2019, (e) updated well cost assumptions by asset, and (f) the reduction in commodity prices from YE 2018 SEC pricing to the current strip (reference prices shown above). (3) Technical PUDs (locations which would reasonably meet the requirements for SEC PUDs other than 5-year development timing) and estimated probable locations were removed, as by definition they are not included in a 1P reserve report. (4) The difference between the resulting value and the YE 2018 Ryder Scott SEC reserve report is reflected in the illustration under the adjustment category "Development and Other" and is intended to reflect timing and other cumulative adjustments, such as updates to commodity price differentials and variations in individual location selection between the two databases.



Reserve Summary (Restricted Group)

Year-End 2018 Ryder Scott 1P Report ⁽¹⁾

Reserve and PV10 Summary
(\$ in millions)

Reserve Category	Reserves			Equiv. MMBoe	PV-10 \$MM
	Oil	Gas	NGL		
	MMBbls	Bcf	MMBbls		
PDP	28	212	37	100	\$489
PDSI	0	1	0	0	(1)
PUD	59	347	61	177	146
Total Proved	86	560	98	277	\$634

3P Management Case ⁽²⁾

Reserve and PV10 Summary
(\$ in millions)

Reserve Category	Reserves			Equiv. MMBoe	PV-10 \$MM
	Oil	Gas	NGL		
	MMBbls	Bcf	MMBbls		
PDP	32	243	42	115	\$673
PDSI	--	2	--	1	4
Development	252	727	132	506	446
Total Proved	285	972	175	622	\$1,124

(1) Represents year-end 2018 Ryder Scott 1P reserve report for restricted subsidiaries using an effective date of 1/1/19 and strip pricing as of 6/27/19.

(2) Management case for restricted subsidiaries using an effective date of 4/1/19 and strip pricing as of 6/27/19.



Illustrative Asset-Level Type Curve Parameters

- ◆ **Type curve parameters represent average for asset**
 - ❖ Weighted average of IPs and initial declines based on wells drilled within specific type curve areas in the first 5 years
- ◆ **Assets generally assume B-Factor of 1.2**
- ◆ **Gas parameters shown net of volume shrinkage**

CATARINA		
Oil	IP (Bbbls/d)	372
	Initial Decline (%)	81%
	Oil EUR (MBbbls)	165
Gas	IP (Mcf/d)	2,729
	Initial Decline (%)	70%
	Gas EUR (MMcf)	1,934
NGL	NGL Yield (Bbl/MMcf)	133
	NGL EUR (MBbbls)	258
3-Stream EUR (MBoe)		745
% Oil		22%

PALMETTO		
Oil	IP (Bbbls/d)	708
	Initial Decline (%)	80%
	Oil EUR (MBbbls)	298
Gas	IP (Mcf/d)	940
	Initial Decline (%)	83%
	Gas EUR (MMcf)	338
NGL	NGL Yield (Bbl/MMcf)	133
	NGL EUR (MBbbls)	45
3-Stream EUR (MBoe)		399
% Oil		75%

COMANCHE		
Oil	IP (Bbbls/d)	377
	Initial Decline (%)	78%
	Oil EUR (MBbbls)	200
Gas	IP (Mcf/d)	870
	Initial Decline (%)	60%
	Gas EUR (MMcf)	879
NGL	NGL Yield (Bbl/MMcf)	148
	NGL EUR (MBbbls)	130
3-Stream EUR (MBoe)		476
% Oil		42%

Note: Illustrative well assumptions: (a) 100% working interest and 75% net royalty interest, (b) wells drilled in June, completed in July and first production in August through the end of economic life, and (c) strip pricing as of 6/27/19.



Representative Type Curve Parameters by Area

- Below are illustrative parameters for certain of the major type curve areas by asset that represent the majority of future development value in the 3P Management Case
- Type curves were constructed using the averages of all completed wells that met appropriate parameters, such as completion designs and lateral lengths that are reflected in future development plans for each area

Type Curve Area	EUR (MBoe)	IRR	Oil-IP	Oil B-Factor	Oil-Di	Gas-IP	Gas B-Factor	Gas-Di	NGL/Gas
Comanche									
BD_AREA_3_1_4729	685	32%	350	1.2	70	950	1.2	50	147.8
BD_AREA_3_1C_4619	222	NM	380	1.2	88	950	1.2	80	147.8
BD_AREA_3_3_5638	831	36%	350	1.2	69	1,250	1.2	50	147.8
BD_AREA_5_7_5700	493	57%	425	1.0	66	350	0.9	41	147.8
Catarina									
BD_CATNC_6009	724	24%	370	1.2	77	1,699	1.2	60	133.2
BD_CATSC_UEFC_6034	1,178	43%	450	1.2	80	3,900	1.2	67	133.2
BD_CATWSO_5915	603	16%	380	1.2	81	1,995	1.2	70	133.2
Maverick									
BD_Maverick_Base	221	21%	430	1.2	79	1	1.2	30	107.5
Palmetto									
BD_BHS_RS2_5000	490	NM	1,100	1.2	89	1,840	1.2	87	133.1

Note: Illustrative well assumptions: (a) 100% working interest and 75% net royalty interest, (b) wells drilled in June, completed in July and first production in August through the end of economic life, and (c) strip pricing as of 6/27/19.

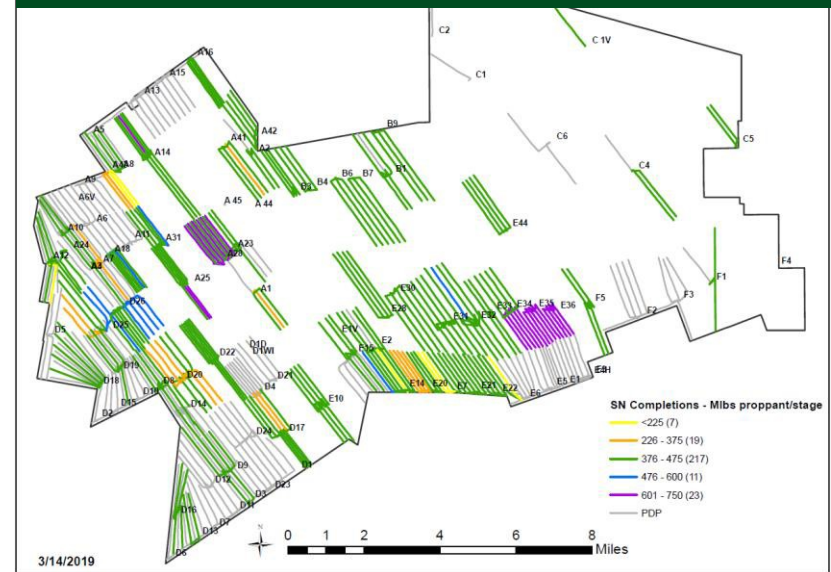
Catarina Completion Design



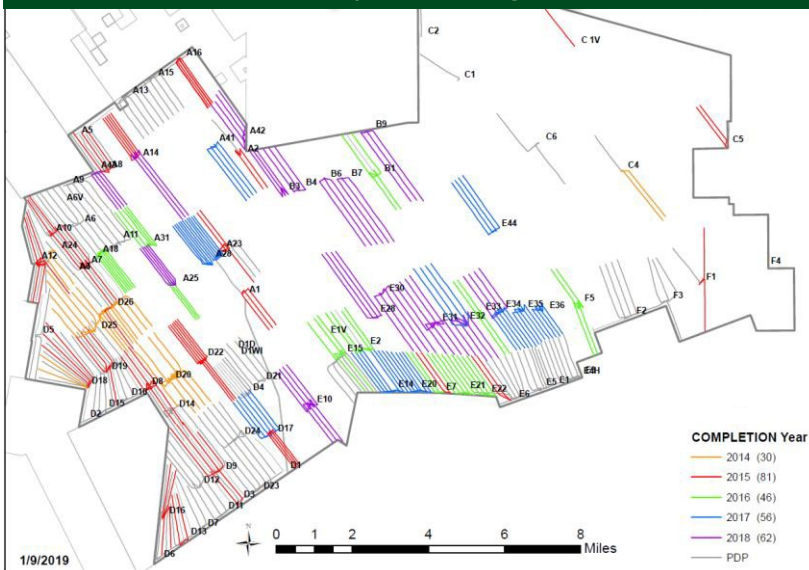
Completion Designs – Evolution

- ◆ Previous operator tested variations of conventional designs
 - ❖ Lower fluid and proppant volumes
 - ❖ "Ball and sleeve" applications
- ◆ 2014 tests of modern completion designs
 - ❖ Varied volume intensities
 - ❖ "Plug and perf" application
- ◆ 2015 testing informed current standard design
 - ❖ ~30 Bbls/ft of fluid and ~1,700 lbs/ft of proppant
- ◆ 2015-2018 tests of high intensity designs were successful in single well applications, but failed to meet expectations in development setting

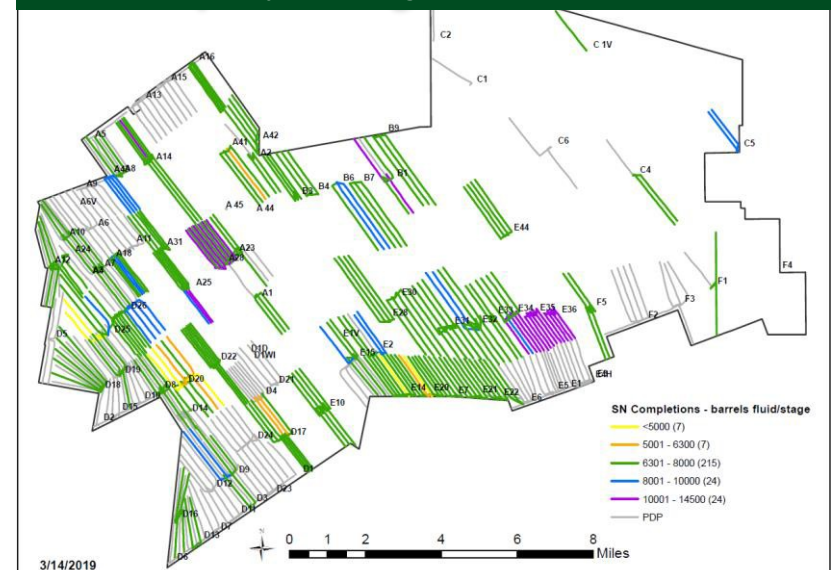
Completion Designs – Proppant Volumes



Completion Timing



Completion Designs – Fluid Volumes





Comanche Completion Design



Completion Design Evolution

- ◆ Prior operator design
 - ❖ ~30 Bbls/ft and ~800 lbs/ft with ~500+ well spacing
- ◆ 2017: Tested the Catarina design with a modified choke strategy
 - ❖ ~30 Bbls/ft and ~1,700 lbs/ft with ~300' well spacing
- ◆ 2017-2018: Tested higher intensity designs
 - ❖ ~50+ Bbls/ft and ~2,000+ lbs/ft on ~300' well spacing
 - ❖ Modified and conservative choke strategies
- ◆ 2018-2019: Delineating successful higher intensity designs
 - ❖ ~50 Bbls/ft and ~2,000 lbs/ft on ~450'+ well spacing
 - ❖ Monitored drawdown strategies



Sanchez Energy Corporation and its Restricted Subsidiaries

(“Restricted Group”)

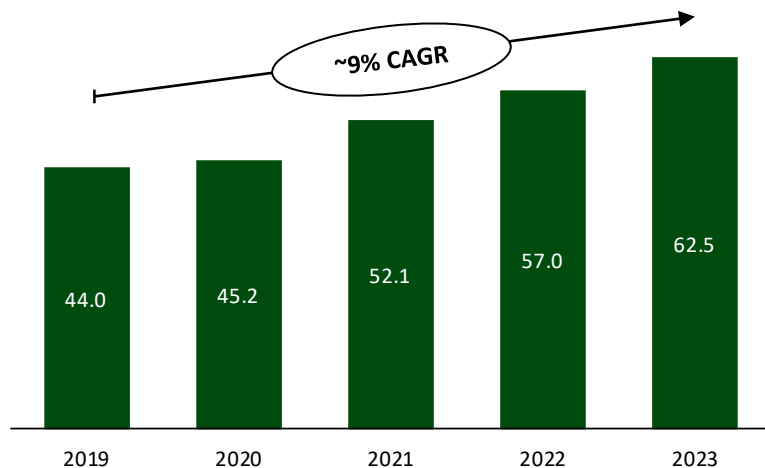
Financial Highlights: Base Case (6/27/19 Strip Pricing)

Restricted Group

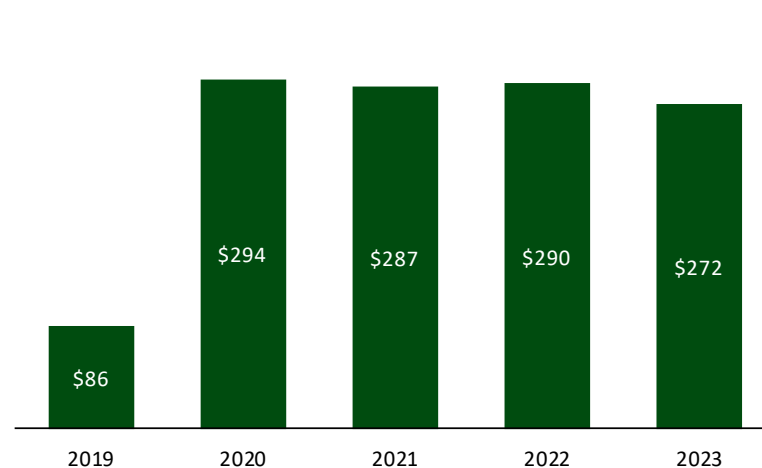
STRICTLY CONFIDENTIAL – SUBJECT TO CONFIDENTIALITY AGREEMENTS – PRELIMINARY – SUBJECT TO SUBSTANTIAL REVISION



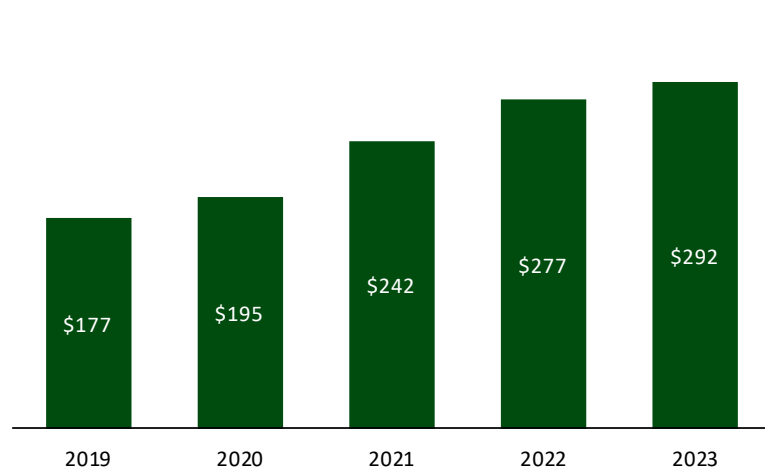
Production (MBoe/d)



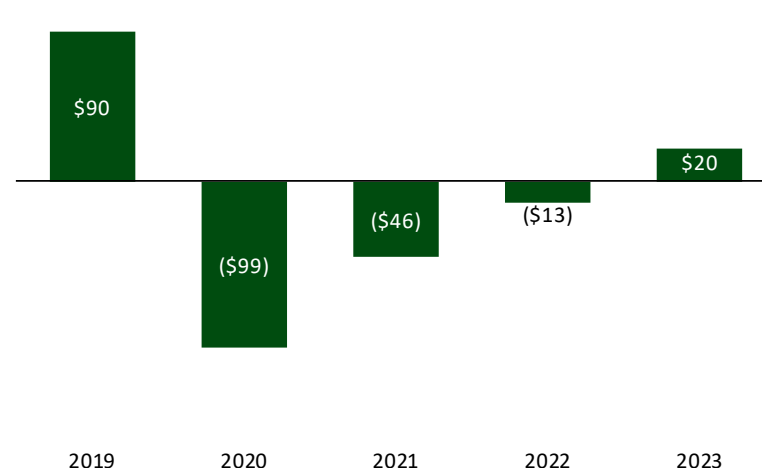
Capital Expenditures (\$MM)



Adjusted EBITDAX (\$MM)



Unlevered Free Cash Flow (\$MM)



Note: Detailed financial forecast provided on page 46.

Summary Projections: Base Case (6/27/19 Strip Pricing)

Restricted Group



(\$ in thousands)

	1Q 19	2Q 19	3Q 19	4Q 19	2019	1Q 20	2Q 20	3Q 20	4Q 20	2020	2021	2022	2023
Net Production:													
Comanche Restricted (Boe/d)	7,933	6,529	5,811	5,930	6,544	5,434	4,923	5,343	5,499	5,300	5,716	6,192	6,342
Non-Comanche Restricted (Boe/d)	45,499	38,568	34,710	31,085	37,419	31,129	37,759	46,835	43,604	39,861	46,358	50,856	56,159
Total Net Production (Boe/d)	53,432	45,098	40,522	37,016	43,962	36,563	42,682	52,178	49,103	45,162	52,074	57,048	62,501
Commodity Price:													
Oil (\$/Bbl)	\$54.90	\$61.38	\$59.45	\$59.17	\$58.73	\$58.36	\$57.43	\$56.61	\$55.99	\$57.10	\$54.88	\$54.16	\$54.22
Gas (\$/MMBtu)	\$3.15	\$2.56	\$2.32	\$2.45	\$2.62	\$2.67	\$2.42	\$2.49	\$2.61	\$2.55	\$2.60	\$2.63	\$2.70
NGL (\$/Bbl)	\$27.82	\$23.66	\$21.54	\$23.96	\$24.24	\$24.64	\$23.54	\$24.27	\$25.62	\$24.52	\$25.63	\$25.81	\$25.52
Realized Price:													
Oil (\$/Bbl)	\$54.63	\$62.09	\$60.17	\$59.87	\$58.90	\$59.01	\$57.99	\$57.12	\$56.54	\$57.52	\$55.33	\$54.60	\$54.66
Gas (\$/Mcf)	\$3.30	\$2.64	\$2.38	\$2.52	\$2.75	\$2.75	\$2.50	\$2.56	\$2.69	\$2.62	\$2.67	\$2.70	\$2.77
NGL (\$/Bbl)	\$17.44	\$13.41	\$12.16	\$13.54	\$14.34	\$13.92	\$13.31	\$13.71	\$14.49	\$13.87	\$14.50	\$14.58	\$14.43
Oil Revenue	\$87,114	\$82,706	\$72,363	\$64,608	\$306,792	\$61,442	\$72,207	\$89,511	\$85,468	\$308,628	\$336,895	\$372,884	\$382,260
Gas Revenue	\$31,014	\$21,349	\$17,565	\$17,079	\$87,008	\$18,348	\$19,254	\$24,264	\$23,623	\$85,488	\$101,028	\$110,473	\$128,279
NGL Revenue	\$28,732	\$19,093	\$15,782	\$16,192	\$79,799	\$16,345	\$18,007	\$22,720	\$22,342	\$79,413	\$96,043	\$104,587	\$117,003
Oil, Gas, & NGL Revenue	\$146,861	\$123,149	\$105,710	\$97,878	\$473,598	\$96,134	\$109,468	\$136,495	\$131,432	\$473,529	\$533,966	\$587,944	\$627,543
Hedge Gain / (Loss)	\$1,740	(\$3,281)	(\$2,160)	(\$2,302)	(\$6,003)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
LOE	\$12,100	\$11,530	\$11,407	\$11,114	\$46,152	\$10,608	\$10,836	\$11,474	\$12,198	\$45,115	\$49,244	\$53,550	\$57,699
Marketing	\$39,209	\$32,549	\$29,449	\$27,213	\$128,419	\$26,721	\$31,088	\$38,398	\$35,379	\$131,587	\$152,090	\$165,404	\$184,031
Deficiencies	\$0	\$4,807	\$6,444	\$7,619	\$18,870	\$7,631	\$5,343	\$2,048	\$3,664	\$18,686	\$8,866	\$6,762	\$6,313
Total Operating Expenses	\$51,308	\$48,886	\$47,301	\$45,946	\$193,441	\$44,960	\$47,267	\$51,920	\$51,241	\$195,388	\$210,200	\$225,717	\$248,043
Production Taxes	\$6,052	\$4,997	\$4,315	\$3,973	\$19,337	\$3,862	\$4,432	\$5,508	\$5,309	\$19,110	\$21,408	\$23,566	\$24,896
Ad Valorem Taxes	\$3,098	\$2,515	\$2,164	\$2,005	\$9,783	\$1,958	\$2,200	\$2,723	\$2,644	\$9,526	\$10,683	\$11,750	\$12,532
Cash G&A ⁽¹⁾	\$19,329	\$17,324	\$13,125	\$13,125	\$62,903	\$13,750	\$13,750	\$13,750	\$13,750	\$55,000	\$50,000	\$50,000	\$50,000
Adjusted EBITDAX	\$63,532	\$46,146	\$36,645	\$30,527	\$176,850	\$31,605	\$41,818	\$62,594	\$58,488	\$194,505	\$241,674	\$276,912	\$292,072
Total Capex	\$12,753	\$23,240	\$19,500	\$30,966	\$86,458	\$73,897	\$124,941	\$56,745	\$38,396	\$293,979	\$287,186	\$290,045	\$272,333
Unlevered Free Cash Flow	\$50,779	\$22,906	\$17,145	(\$438)	\$90,392	(\$42,293)	(\$83,123)	\$5,849	\$20,093	(\$99,475)	(\$45,512)	(\$13,133)	\$19,739

(1) Reflects estimated Consolidated G&A less an assumed allocation to UnSub of approximately \$7.5 million for 2019 and \$5 million per year thereafter, based on certain historical trends and future expectations. Actual G&A allocation between Restricted Group and UnSub may be more or less than the amounts shown, with such allocation determined in accordance with the applicable contract.

Summary Projections: 13 Week Cash Flow Forecast

Restricted Group

STRICTLY CONFIDENTIAL – SUBJECT TO CONFIDENTIALITY AGREEMENTS – PRELIMINARY – SUBJECT TO SUBSTANTIAL REVISION



Sanchez Energy Corp¹

13 Week Cash Flow

Week Ending:	Jul 5 '19	Jul 12 '19	Jul 19 '19	Jul 26 '19	Aug 2 '19	Aug 9 '19	Aug 16 '19	Aug 23 '19	Aug 30 '19	Sep 6 '19	Sep 13 '19	Sep 20 '19	Sep 27 '19	Total
	1	2	3	4	5	6	7	8	9	10	11	12	13	Total Forecast
(\$ in 000s)	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Wk 1 - 13
Cash & Cash Equivalents - Beginning	\$ 185,079	\$ 98,218	\$ 99,473	\$ 97,778	\$ 177,386	\$ 83,878	\$ 95,248	\$ 65,216	\$ 131,132	\$ 75,533	\$ 82,973	\$ 71,487	\$ 170,853	\$ 185,079
Cash Receipts														
Gross Production Receipts	4,473	-	21,957	142,286	777	-	-	117,433	42,308	387	-	113,844	43,602	487,068
Cash Calls & JIB Receipts	-	15,475	21,473	3,084	3,638	28,368	3,630	-	3,630	27,813	400	3,623	-	111,133
Hedge Settlements	-	340	-	-	-	351	-	-	-	347	-	-	-	1,038
Other	10	86	-	-	6	83	-	-	-	6	83	-	-	274
Total Cash Receipts	\$ 4,483	\$ 15,900	\$ 43,430	\$ 145,370	\$ 4,422	\$ 28,802	\$ 3,630	\$ 117,433	\$ 45,938	\$ 28,554	\$ 483	\$ 117,467	\$ 43,602	\$ 599,512
Cash Disbursements														
Capex	(4,561)	(4,561)	(4,586)	(4,561)	(4,561)	(7,427)	(7,427)	(7,427)	(7,427)	(5,682)	(5,682)	(5,682)	(5,682)	(75,265)
Lease Operating Expense	(3,192)	(3,192)	(3,192)	(3,192)	(3,192)	(3,966)	(3,966)	(3,966)	(3,966)	(3,158)	(3,158)	(3,158)	(3,158)	(44,457)
Gathering / Firm Transportation	(11,364)	(1,020)	(811)	(10,457)	(246)	(5,461)	(1,254)	(5,553)	(5,836)	(5,367)	(980)	(1,836)	(10,380)	(60,566)
Gas Purchases Disbursements	-	-	-	(2,000)	-	-	-	-	(2,000)	-	-	-	(2,000)	(6,000)
Hedge Settlements	-	(413)	-	-	-	(427)	-	-	-	(444)	-	-	-	(1,284)
Royalties & Working Interest Payments	(71,923)	-	(778)	(35,937)	(86,637)	-	(740)	(27,666)	(79,997)	(6,312)	-	(719)	(28,309)	(339,018)
Production & Ad Valorem Tax	-	-	-	(7,420)	-	-	-	(6,365)	-	-	-	(6,166)	-	(19,950)
G&A / Other	(150)	(5,458)	(540)	(2,195)	(3,150)	(150)	(2,150)	(540)	(2,195)	(150)	(2,150)	(540)	(2,195)	(21,563)
Operating Cash Disbursements	\$ (91,190)	\$ (14,644)	\$ (9,906)	\$ (65,762)	\$ (97,786)	\$ (17,431)	\$ (15,537)	\$ (51,517)	\$ (101,422)	\$ (21,114)	\$ (11,969)	\$ (18,100)	\$ (51,724)	\$ (568,103)
Total Operating Cash Flow	\$ (86,707)	\$ 1,255	\$ 33,524	\$ 79,609	\$ (93,365)	\$ 11,371	\$ (11,908)	\$ 65,917	\$ (55,484)	\$ 7,440	\$ (11,487)	\$ 99,367	\$ (8,122)	\$ 31,410
Financing Related Cash Flows														
Debt Service Payments	(155)	-	(35,219)	-	(144)	-	(18,125)	-	(115)	-	-	-	-	(53,757)
Net Cash Flow Prior to DIP Financing	\$ (86,862)	\$ 1,255	\$ (1,695)	\$ 79,609	\$ (93,508)	\$ 11,371	\$ (30,033)	\$ 65,917	\$ (55,599)	\$ 7,440	\$ (11,487)	\$ 99,367	\$ (8,122)	\$ (22,348)
Ending Operating Cash Balance	\$ 98,218	\$ 99,473	\$ 97,778	\$ 177,386	\$ 83,878	\$ 95,248	\$ 65,216	\$ 131,132	\$ 75,533	\$ 82,973	\$ 71,487	\$ 170,853	\$ 162,732	\$ 162,732
Memo: Cash Excluding SNEFM														
Operating Cash	\$ 98,218	\$ 99,473	\$ 97,778	\$ 177,386	\$ 83,878	\$ 95,248	\$ 65,216	\$ 131,132	\$ 75,533	\$ 82,973	\$ 71,487	\$ 170,853	\$ 162,732	\$ 162,732
SN EF Maverick Cash Balance	15,321	13,234	28,816	114,744	25,857	38,952	31,916	87,113	29,733	38,370	29,894	108,721	109,345	109,345
Operating Cash less SN EF Maverick	\$ 82,897	\$ 86,239	\$ 68,962	\$ 62,643	\$ 58,021	\$ 56,296	\$ 33,299	\$ 44,019	\$ 45,800	\$ 44,603	\$ 41,593	\$ 62,133	\$ 53,387	\$ 53,387

¹ Excludes Cash of SN EF UnSub, LP

Note: SN UR Holdings, LLC, SN EF UnSub, LP and SN EF Maverick, LLC had cash balances of \$63.5 million, \$18.4 million and \$76.1 million, respectively as of 3/31/19 and projected to be \$63.2 million, \$17.7 million and \$104.3 million, respectively as of 6/30/19



Key Takeaways

- ◆ **Proven management team with a strong track record of creating value and driving growth**
- ◆ **Unique asset base with large, contiguous acreage position and extensive future inventory**
- ◆ **Focused on generating value through efficient cost management**
- ◆ **Actively managing production decline rates to provide greater asset stability**
- ◆ **Business plan demonstrates operational flexibility to maximize free cash flow**
- ◆ **Opportunity for significant margin expansion from a modest commodity price recovery**



Appendices



A. Consolidated and UnSub Financial Projections



Sanchez Energy Corporation and its Consolidated Subsidiaries

(“Consolidated”)

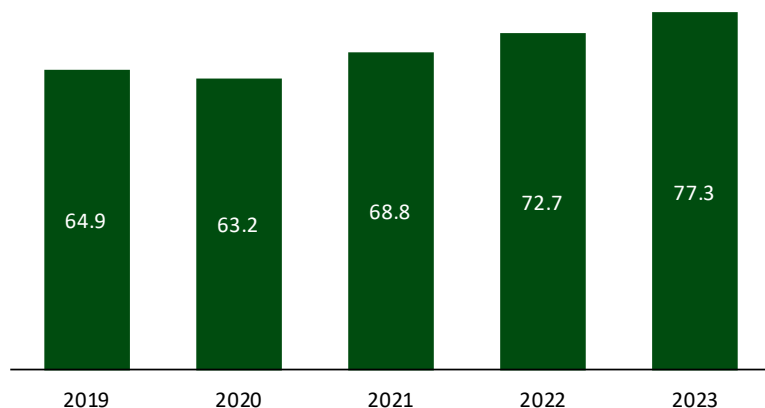
Financial Highlights: Base Case (6/27/19 Strip Pricing)

Consolidated

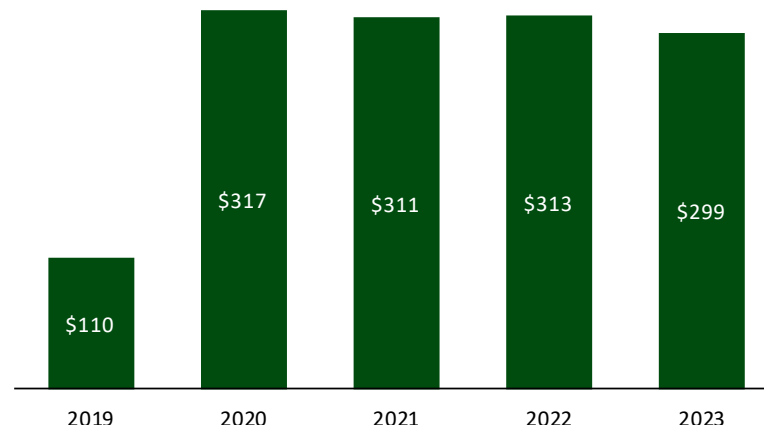
STRICTLY CONFIDENTIAL – SUBJECT TO CONFIDENTIALITY AGREEMENTS – PRELIMINARY – SUBJECT TO SUBSTANTIAL REVISION



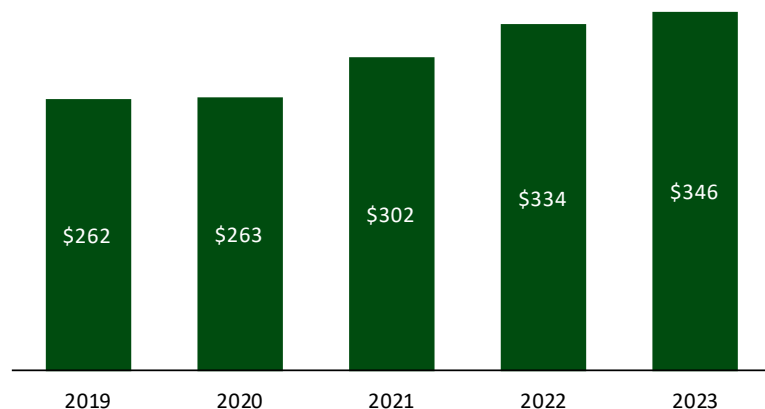
Production (MBoe/d)



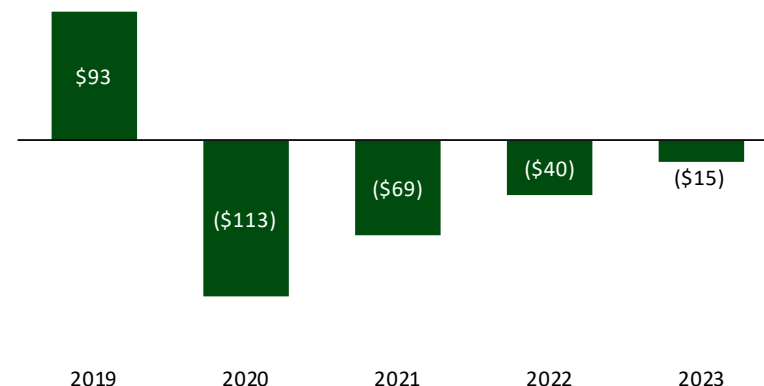
Capital Expenditures (\$MM)



Adjusted EBITDAX (\$MM)



Free Cash Flow (\$MM) ⁽¹⁾



Note: Detailed financial forecast provided on page 53.

(1) Figures represent Restricted Group unlevered cash flow combined with UnSub levered cash flow (including interest on bank debt and preferred dividends).

Summary Projections: Base Case (6/27/19 Strip Pricing)


Consolidated



(\$ in thousands)

	1Q 19	2Q 19	3Q 19	4Q 19	2019	1Q 20	2Q 20	3Q 20	4Q 20	2020	2021	2022	2023
Net Production:													
Comanche (Boe/d)	30,770	27,876	25,909	25,529	27,502	24,357	23,007	23,080	22,900	23,334	22,393	21,892	21,109
Non-Comanche (Boe/d)	45,499	38,568	34,710	31,085	37,419	31,129	37,759	46,835	43,604	39,861	46,358	50,856	56,159
Total Net Production (Boe/d)	76,268	66,444	60,620	56,615	64,921	55,486	60,766	69,916	66,504	63,195	68,750	72,748	77,267
Commodity Price:													
Oil (\$/Bbl)	\$54.90	\$61.38	\$59.45	\$59.17	\$58.73	\$58.36	\$57.43	\$56.61	\$55.99	\$57.10	\$54.88	\$54.16	\$54.22
Gas (\$/MMBtu)	\$3.15	\$2.56	\$2.32	\$2.45	\$2.62	\$2.67	\$2.42	\$2.49	\$2.61	\$2.55	\$2.60	\$2.63	\$2.70
NGL (\$/Bbl)	\$27.82	\$23.66	\$21.54	\$23.96	\$24.24	\$24.64	\$23.54	\$24.27	\$25.62	\$24.52	\$25.63	\$25.81	\$25.52
Realized Price:													
Oil (\$/Bbl)	\$54.81	\$61.71	\$59.77	\$59.45	\$58.70	\$58.62	\$57.68	\$56.87	\$56.28	\$57.27	\$55.11	\$54.40	\$54.48
Gas (\$/Mcf)	\$3.27	\$2.65	\$2.39	\$2.53	\$2.74	\$2.76	\$2.50	\$2.57	\$2.70	\$2.63	\$2.68	\$2.71	\$2.78
NGL (\$/Bbl)	\$17.34	\$13.37	\$12.14	\$13.50	\$14.22	\$13.89	\$13.27	\$13.69	\$14.46	\$13.83	\$14.47	\$14.56	\$14.41
Oil Revenue	\$128,028	\$120,780	\$107,051	\$98,292	\$454,151	\$92,963	\$101,575	\$119,001	\$114,086	\$427,626	\$443,912	\$474,213	\$478,566
Gas Revenue	\$43,049	\$31,029	\$25,938	\$25,704	\$125,719	\$27,378	\$27,111	\$32,172	\$31,752	\$118,413	\$131,792	\$139,426	\$156,107
NGL Revenue	\$40,500	\$28,554	\$24,008	\$25,114	\$118,177	\$25,137	\$26,067	\$30,858	\$30,769	\$112,831	\$128,052	\$134,658	\$144,831
Oil, Gas, & NGL Revenue	\$211,577	\$180,362	\$156,997	\$149,110	\$698,046	\$145,478	\$154,754	\$182,032	\$176,607	\$658,870	\$703,756	\$748,297	\$779,503
Hedge Gain / (Loss)	\$218	(\$5,965)	(\$3,337)	(\$3,632)	(\$12,716)	(\$1,497)	(\$3)	\$1,205	(\$1,013)	(\$1,309)	\$0	\$0	\$0
LOE	\$22,638	\$20,555	\$20,417	\$20,039	\$83,649	\$18,420	\$18,629	\$19,162	\$19,825	\$76,036	\$79,233	\$82,780	\$86,386
Marketing	\$56,567	\$51,038	\$47,098	\$44,422	\$199,125	\$43,183	\$46,857	\$53,928	\$50,614	\$194,583	\$209,971	\$219,622	\$234,900
Deficiencies	\$0	\$5,664	\$7,571	\$8,788	\$22,023	\$8,769	\$6,678	\$3,431	\$5,056	\$23,935	\$15,159	\$11,902	\$10,463
Total Operating Expenses	\$79,206	\$77,256	\$75,086	\$73,249	\$304,798	\$70,372	\$72,164	\$76,522	\$75,495	\$294,553	\$304,363	\$314,304	\$331,749
Production Taxes	\$8,283	\$7,136	\$6,244	\$5,883	\$27,547	\$5,680	\$6,112	\$7,196	\$6,971	\$25,960	\$27,647	\$29,462	\$30,485
Ad Valorem Taxes	\$4,767	\$3,837	\$3,348	\$3,189	\$15,141	\$3,099	\$3,247	\$3,776	\$3,689	\$13,810	\$14,609	\$15,457	\$16,045
Cash G&A ⁽¹⁾	\$21,250	\$19,199	\$15,000	\$15,000	\$70,448	\$15,000	\$15,000	\$15,000	\$15,000	\$60,000	\$55,000	\$55,000	\$55,000
Adjusted EBITDAX	\$92,969	\$66,969	\$53,980	\$48,157	\$262,076	\$49,829	\$58,227	\$80,743	\$74,439	\$263,238	\$302,138	\$334,074	\$346,224
Total Capex	\$18,149	\$28,389	\$27,776	\$35,470	\$109,784	\$76,976	\$133,404	\$62,448	\$43,759	\$316,587	\$310,882	\$312,572	\$298,542
Unlevered Free Cash Flow	\$74,820	\$38,580	\$26,204	\$12,687	\$152,291	(\$27,147)	(\$75,177)	\$18,295	\$30,680	(\$53,349)	(\$8,744)	\$21,502	\$47,682
UnSub Preferred Dividends + Interest	\$2,283	\$27,191	\$14,715	\$14,759	\$58,948	\$14,769	\$14,789	\$14,848	\$14,885	\$59,291	\$60,100	\$61,337	\$62,684
Free Cash Flow	\$72,536	\$11,389	\$11,489	(\$2,072)	\$93,343	(\$41,916)	(\$89,966)	\$3,447	\$15,795	(\$112,640)	(\$68,844)	(\$39,836)	(\$15,002)

(1) Reflects an assumed allocation to UnSub of approximately \$7.5 million for 2019 and \$5 million per year thereafter, based on certain historical trends and future expectations. Actual G&A allocation between Restricted Group and UnSub may be more or less than the amounts shown, with such allocation determined in accordance with the applicable contract.



SN EF UnSub, LP

(“UnSub”)

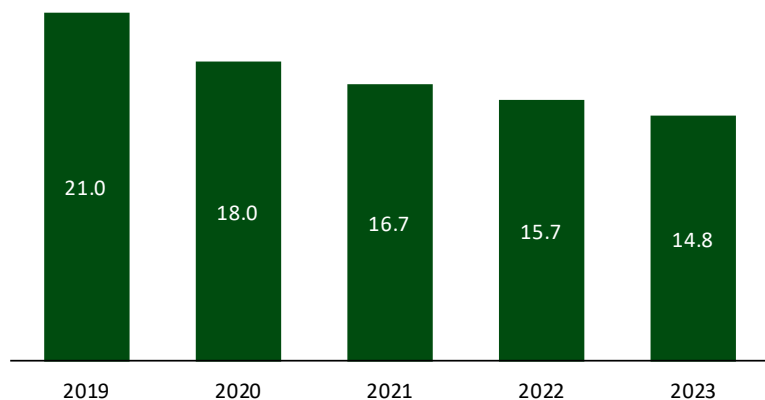
Financial Highlights: Base Case (6/27/19 Strip Pricing)

UnSub

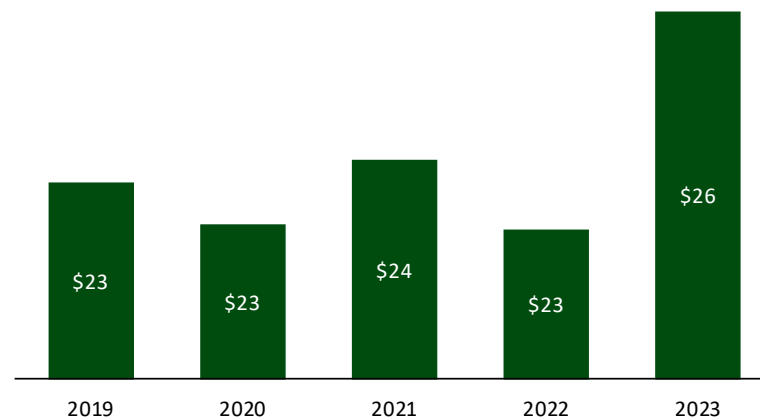
STRICTLY CONFIDENTIAL – SUBJECT TO CONFIDENTIALITY AGREEMENTS – PRELIMINARY – SUBJECT TO SUBSTANTIAL REVISION



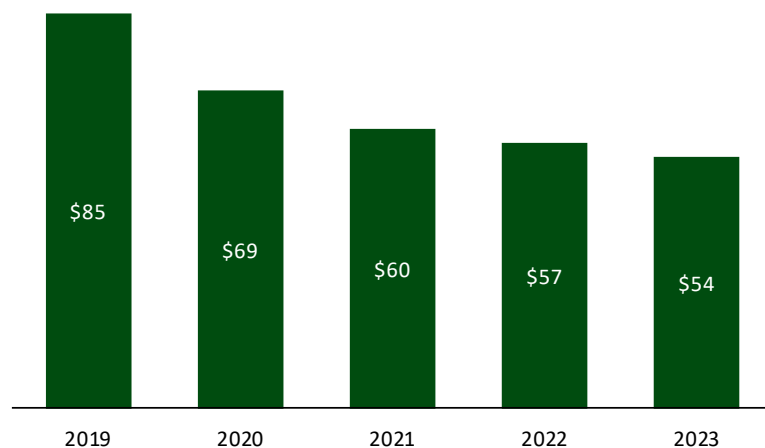
Production (MBoe/d)



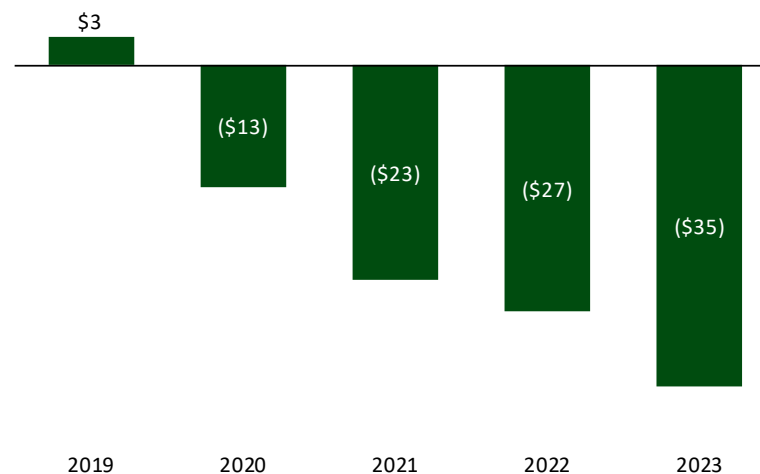
Capital Expenditures (\$MM)



Adjusted EBITDAX (\$MM)



Levered Free Cash Flow (\$MM) ⁽¹⁾



Note: Detailed financial forecast provided on page 56.

(1) Includes interest on bank debt and preferred dividends.



Summary Projections: Base Case (6/27/19 Strip Pricing)

UnSub

(\$ in thousands)

	1Q 19	2Q 19	3Q 19	4Q 19	2019	1Q 20	2Q 20	3Q 20	4Q 20	2020	2021	2022	2023
Total Net Production (Boe/d)	22,837	21,347	20,098	19,599	20,959	18,922	18,084	17,737	17,401	18,034	16,677	15,700	14,767
Commodity Price:													
Oil (\$/Bbl)	\$54.90	\$61.38	\$59.45	\$59.17	\$58.73	\$58.36	\$57.43	\$56.61	\$55.99	\$57.10	\$54.88	\$54.16	\$54.22
Gas (\$/MMBtu)	\$3.15	\$2.56	\$2.32	\$2.45	\$2.62	\$2.67	\$2.42	\$2.49	\$2.61	\$2.55	\$2.60	\$2.63	\$2.70
NGL (\$/Bbl)	\$27.82	\$23.66	\$21.54	\$23.96	\$24.24	\$24.64	\$23.54	\$24.27	\$25.62	\$24.52	\$25.63	\$25.81	\$25.52
Realized Price:													
Oil (\$/Bbl)	\$55.21	\$60.90	\$58.95	\$58.68	\$58.27	\$57.87	\$56.94	\$56.14	\$55.51	\$56.63	\$54.42	\$53.70	\$53.77
Gas (\$/Mcf)	\$3.20	\$2.66	\$2.41	\$2.54	\$2.72	\$2.78	\$2.52	\$2.59	\$2.72	\$2.65	\$2.71	\$2.73	\$2.80
NGL (\$/Bbl)	\$17.11	\$13.29	\$12.08	\$13.44	\$13.98	\$13.82	\$13.20	\$13.61	\$14.37	\$13.75	\$14.38	\$14.48	\$14.31
Oil Revenue	\$40,913	\$38,073	\$34,689	\$33,684	\$147,359	\$31,522	\$29,368	\$29,490	\$28,618	\$118,999	\$107,017	\$101,328	\$96,305
Gas Revenue	\$12,035	\$9,679	\$8,372	\$8,625	\$38,711	\$9,030	\$7,857	\$7,908	\$8,129	\$32,925	\$30,764	\$28,953	\$27,828
NGL Revenue	\$11,768	\$9,461	\$8,226	\$8,923	\$38,378	\$8,792	\$8,060	\$8,138	\$8,427	\$33,417	\$32,009	\$30,071	\$27,828
Oil, Gas, & NGL Revenue	\$64,716	\$57,214	\$51,287	\$51,231	\$224,448	\$49,344	\$45,286	\$45,537	\$45,175	\$185,341	\$169,790	\$160,352	\$151,961
Hedge Gain / (Loss)	(\$1,522)	(\$2,684)	(\$1,177)	(\$1,329)	(\$6,713)	(\$1,497)	(\$3)	\$1,205	(\$1,013)	(\$1,309)	\$0	\$0	\$0
LOE	\$10,539	\$9,024	\$9,010	\$8,924	\$37,497	\$7,813	\$7,793	\$7,688	\$7,627	\$30,920	\$29,989	\$29,230	\$28,687
Marketing	\$17,359	\$18,489	\$17,649	\$17,210	\$70,706	\$16,461	\$15,769	\$15,530	\$15,235	\$62,996	\$57,880	\$54,218	\$50,870
Deficiencies	\$0	\$857	\$1,127	\$1,169	\$3,153	\$1,139	\$1,335	\$1,383	\$1,392	\$5,249	\$6,293	\$5,140	\$4,151
Total Operating Expenses	\$27,897	\$28,370	\$27,786	\$27,303	\$111,357	\$25,413	\$24,897	\$24,602	\$24,254	\$99,165	\$94,163	\$88,587	\$83,707
Production Taxes	\$2,231	\$2,139	\$1,929	\$1,910	\$8,210	\$1,819	\$1,680	\$1,688	\$1,663	\$6,849	\$6,238	\$5,897	\$5,589
Ad Valorem Taxes	\$1,668	\$1,322	\$1,185	\$1,184	\$5,359	\$1,141	\$1,047	\$1,052	\$1,044	\$4,284	\$3,925	\$3,707	\$3,513
Cash G&A ⁽¹⁾	\$1,921	\$1,875	\$1,875	\$1,875	\$7,546	\$1,250	\$1,250	\$1,250	\$1,250	\$5,000	\$5,000	\$5,000	\$5,000
Reconciling Items to EBITDAX	(\$39)	\$0	\$0	\$0	(\$39)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Adjusted EBITDAX	\$29,437	\$20,823	\$17,335	\$17,630	\$85,226	\$18,224	\$16,409	\$18,149	\$15,951	\$68,734	\$60,463	\$57,162	\$54,152
Total Capex	\$5,396	\$5,149	\$8,276	\$4,505	\$23,326	\$3,079	\$8,463	\$5,703	\$5,364	\$22,608	\$23,695	\$22,527	\$26,209
Unlevered Free Cash Flow	\$24,041	\$15,674	\$9,059	\$13,126	\$61,900	\$15,145	\$7,946	\$12,447	\$10,587	\$46,126	\$36,768	\$34,635	\$27,943
Preferred Dividends + Interest	\$2,283	\$27,191	\$14,715	\$14,759	\$58,948	\$14,769	\$14,789	\$14,848	\$14,885	\$59,291	\$60,100	\$61,337	\$62,684
Free Cash Flow	\$21,757	(\$11,517)	(\$5,656)	(\$1,633)	\$2,951	\$377	(\$6,843)	(\$2,402)	(\$4,298)	(\$13,165)	(\$23,332)	(\$26,703)	(\$34,741)

Note: All UnSub net production from Comanche asset.

(1) Reflects an assumed allocation to UnSub of approximately \$7.5 million for 2019 and \$5 million per year thereafter, based on certain historical trends and future expectations. Actual G&A allocation between Restricted Group and UnSub may be more or less than the amounts shown, with such allocation determined in accordance with the applicable contract.



B. Corporate G&A Overview



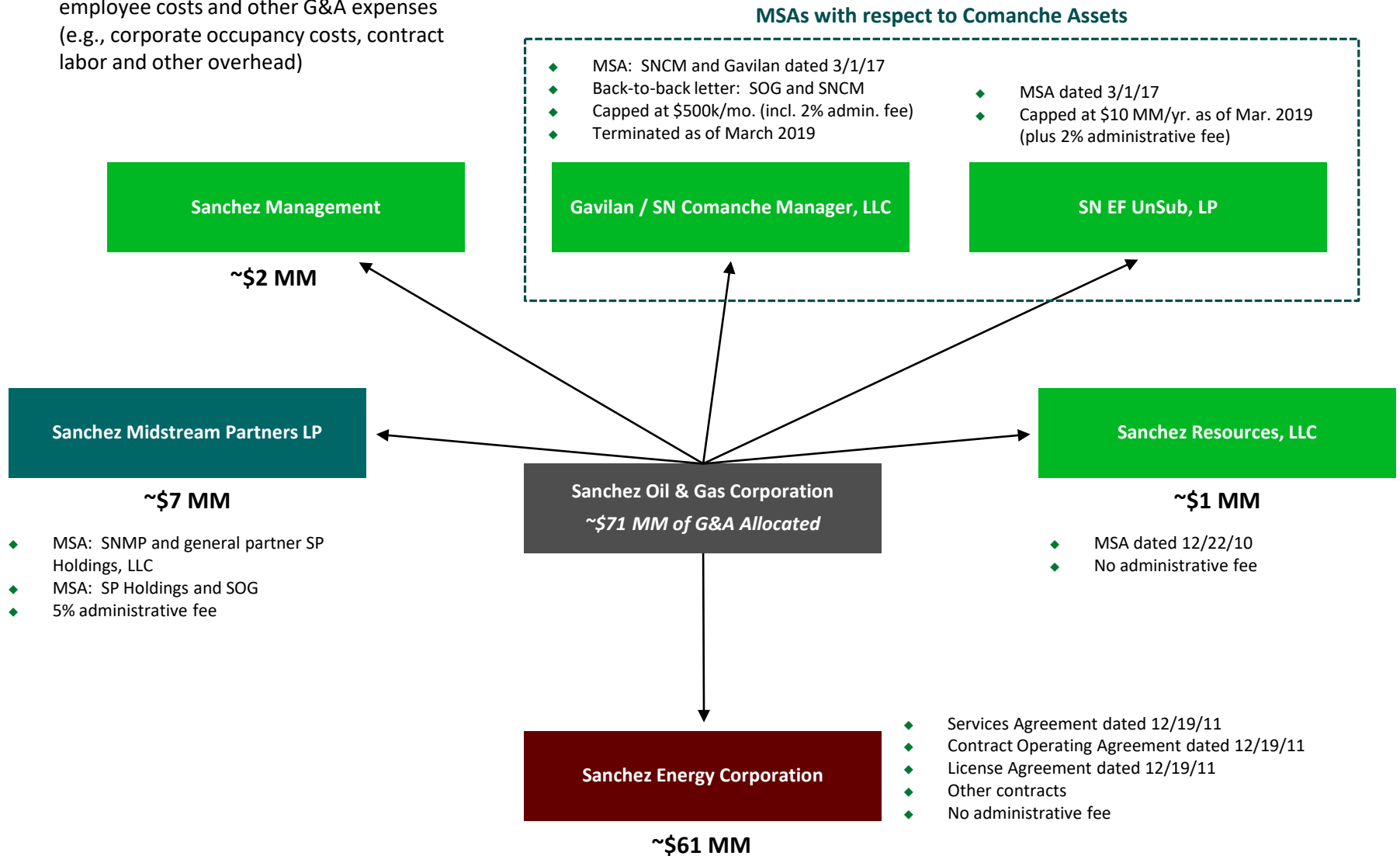
G&A Allocation Process and Methodology Overview

- ◆ **SN generally incurs G&A in two ways:**
 - ❖ Directly in its own name (e.g., professional fees, various insurance policies and other SN agreements)
 - ❖ Indirectly based on estimated allocations from SOG (e.g., office/field staff and other services provided by SOG)
- ◆ **SOG is a service platform and allocates costs on a pass-through basis primarily to:**
 - ❖ SN, without any mark-up
 - ❖ SNMP, with a 5% mark-up based on certain tax considerations
 - ❖ UnSub, subject to caps, with a 2% administrative fee which has historically been credited back to SN
 - ❖ Gavilan Resources, subject to caps, inclusive of a 2% administrative fee (MSA with Gavilan was terminated in March 2019)
- ◆ **Management compensation: management costs are generally allocated to the entities the individuals serve. For example, the SN CEO/CFO are allocated to SN, and the SNMP CEO/CFO are allocated to SNMP.**
- ◆ **Employee compensation:**
 - ❖ Employees are categorized based on their work assignment. Direct employees are allocated to the entities they serve, while indirect employees are allocated based on a twice-annual review of timesheets which record time spent serving each entity.
 - ❖ Most employees regularly complete timesheets, and SOG reviews a representative sample set of timesheets to determine the entity allocation that will be applied to the broader indirect employee group and other non-employee G&A items.
- ◆ **In addition, SN adheres to contractual MSA provisions to determine the amount of its overall G&A which may be allocated to UnSub and Gavilan with respect to the Comanche Assets.**
- ◆ **SN advances funds to SOG at various intervals each month to cover its projected G&A allocation, giving consideration to the size and timing of expenses, such as payroll, lease payments and insurance premiums.**



Summary of 2018 SOG G&A Allocation Among Entities

- Allocated amounts generally include employee costs and other G&A expenses (e.g., corporate occupancy costs, contract labor and other overhead)

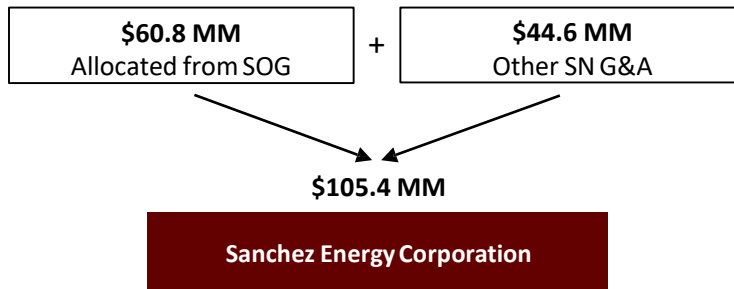




Summary of 2018 SN G&A Allocation

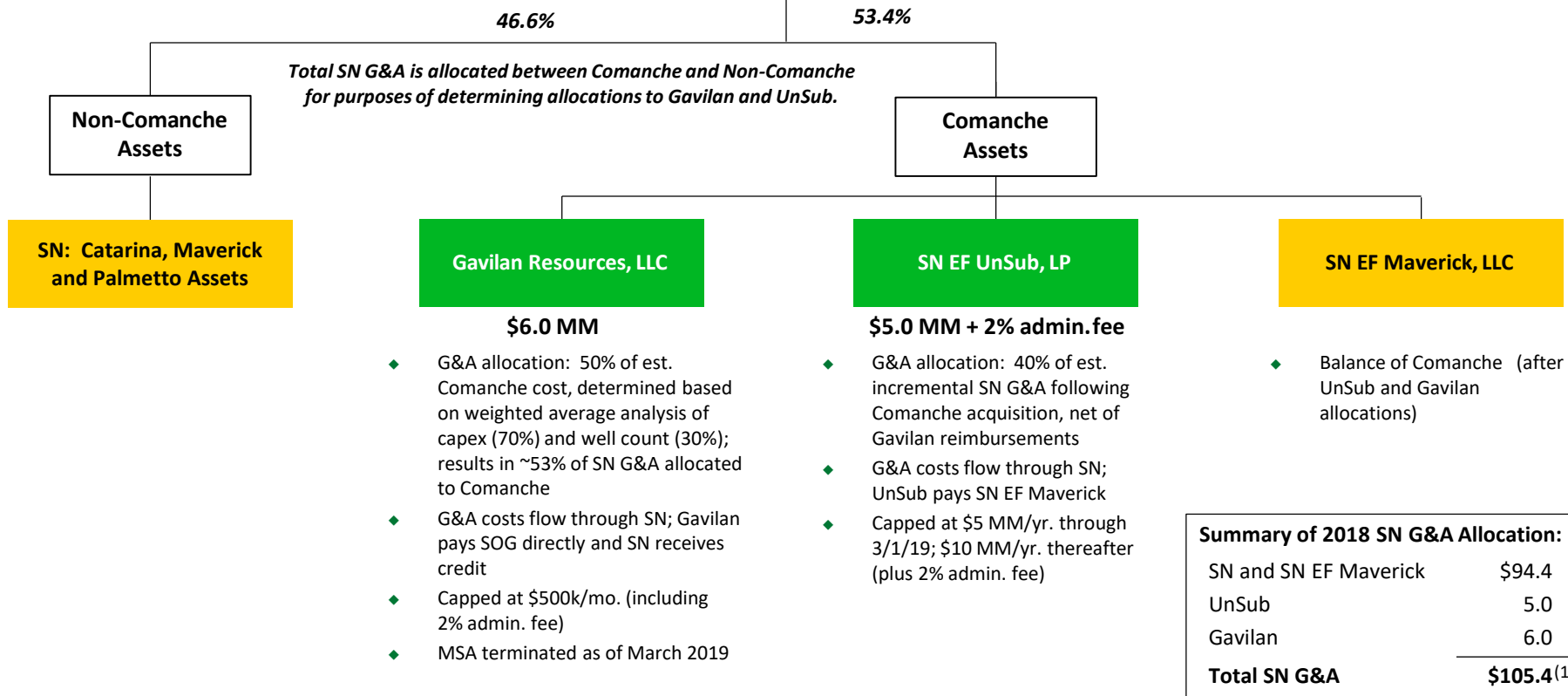
Summary of G&A Allocated from SOG

Field employees	\$8.0
Other dedicated employees	2.6
Total dedicated employees	10.6
Management	5.4
Corporate staff	30.0
Total allocated employees	35.5
Office rent / utilities	5.4
Contract labor	2.7
Other overhead	6.6
Other allocated G&A	14.7
Total allocation from SOG	\$60.8



Summary of Other SN G&A

Professional fees	\$33.7
Information technology and software	5.4
Board of Directors fees	1.5
Company aircraft	2.1
Investor relations / business development	2.1
Other adjustments	-0.3
Total	\$44.6



Note: All amounts are based on cost accruals and represent base G&A allocations from SOG, unless otherwise indicated.

(1) Net of COPAS allocation of ~\$18.7 million. SN's reported 2018 G&A was ~\$98 million.



C. Commodity Market Backdrop and Summary Capitalization



Commodity Price Backdrop

WTI – Present (As of June 2019)



	2019	2020	2021	2022
WTI Strip (\$/Bbl)	\$58.99	\$55.98	\$54.75	\$54.59
% Change Since Oct. 2018	(13.7%)	(13.3%)	(9.8%)	(5.4%)
Henry Hub Strip (\$/MMBtu)	\$2.67	\$2.78	\$2.79	\$2.80
% Change Since Oct. 2018	(10.0%)	0.3%	2.1%	1.7%

Source: Bloomberg and Capital IQ as of 6/26/19.

Note: Strip prices listed in tables above are as of **year-end** (i.e., 2019 WTI strip is the monthly strip price for December 2019).



Summary Capitalization

(\$mm)	Maturity	Amount Outstanding	Interest Rate	Interest Expense	Market Price
SN Secured Debt:					
1st Lien Credit Facility ⁽¹⁾	Feb-23	--	L+3.250%	\$0	N/A
7.25% 1st Lien Notes	Feb-23	500	7.250%	36	77.9¢
Total SN Secured Debt		\$500		\$36	
SN Unsecured Debt:					
7.75% Notes	Jun-21	\$600	7.750%	\$47	5.3¢
6.125% Notes	Jan-23	1,150	6.125%	70	4.2¢
Total SN Unsecured Debt		\$1,750		\$117	
Total SN Recourse Debt		\$2,250		\$153	
UnSub Debt:					
1st Lien UnSub Credit Facility	Mar-22	\$165	L+2.500%	\$9	N/A
Total UnSub Debt		\$165		\$9	
Other Non-Recourse Debt:					
SR Credit Facility	Aug-18	23	5.359%	\$1	N/A
4.59% Subsidiary Term Loan	Aug-22	4	4.590%	0	N/A
Total Non-Recourse Debt		\$27		\$1	
Total Debt		\$2,442		\$164	
Preferred Securities:					
UnSub Preferred		\$500	10.000%	\$50	N/A
SN Series A Preferred ⁽²⁾		39	4.875%	3	\$0.21
SN Series B Preferred ⁽²⁾		126	6.500%	8	\$0.10
Total Preferred Securities		\$665		\$61	

Source: Bloomberg and Capital IQ as of 6/26/19.

Note: Please refer to the Company's SEC filings for a complete description of its capitalization and outstanding securities.

(1) Represents a \$25 million first lien, first-out working capital and letter of credit facility, of which approximately \$17 million is currently utilized for an outstanding letter of credit issued in January 2019.

(2) Series A and Series B preferred outstanding amounts reflect a liquidation preference of \$50/share.



Non-GAAP Financial Measure Reconciliation

Adjusted EBITDAX, Unlevered Free Cash Flow and Free Cash Flow Reconciliation

	1Q 2019					
	<u>Consolidated</u>	<u>Restricted</u>	<u>UnSub</u>	<u>Eliminations</u>	<u>Entity Adj./Other</u>	
Reconciliation Table:						
Reported net income (loss)	\$ (67.3)	\$ (45.6)	\$ (19.7)	\$ (3.2)	\$	1.2
Plus:						
Interest expense	44.6	38.8	2.3	-		3.4
Amortization of debt issuance costs	-	2.2	1.0	-		(3.2)
Net (gains) losses on commodity derivative contracts	48.4	18.1	30.4	-		-
Net settlements paid on commodity derivative contracts	(3.5)	(2.0)	(1.5)	-		-
Exploration expense	1.3	1.1	0.2	-		-
Depreciation, depletion, amortization and accretion	67.5	47.3	16.9	3.1		0.3
Impairment of oil and natural gas properties	3.9	3.7	-	-		0.2
Non-cash stock-based compensation (benefit) expense	0.1	0.1	-	-		-
Income tax expense	0.4	0.4	-	-		-
(Gains) losses on other derivatives	(0.3)	(0.3)	-	-		-
(Gains) losses on investments	(1.5)	-	-	-		(1.5)
Gains on disposal of assets	-	-	-	-		-
Interest income	(0.6)	(0.2)	-	-		(0.4)
Adjusted EBITDAX	\$ 93.0	\$ 63.6	\$ 29.4			
Plus:						
Incurred capital expenditures	(18.1)	(12.8)	(5.4)			
Unlevered Free Cash Flow	\$ 74.8	\$ 50.9	\$ 24.0			
Plus:						
Cash paid preferred dividends & interest at UnSub	(2.3)		(2.3)			
Free Cash Flow	\$ 72.5	\$ 50.9	\$ 21.8			

Adjusted EBITDAX, Unlevered Free Cash Flow and Free Cash Flow are non-GAAP financial measures that are used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess our operating performance as compared to that of other companies in our industry, without regard to financing methods, capital structure or historical costs basis. It is also used to assess our ability to incur and service debt and fund capital expenditures. Our Adjusted EBITDAX, Unlevered Free Cash Flow and Free Cash Flow should not be considered an alternative to net income (loss), operating income (loss), cash flows provided by (used in) operating activities or any other measure of financial performance or liquidity presented in accordance with U.S. GAAP. Our Adjusted EBITDAX, Unlevered Free Cash Flow and Free Cash Flow may not be comparable to similarly titled measures of another company because all companies may not calculate these non-GAAP financial measures in the same manner.