



Talos Energy Announces First Quarter 2023 Operational and Financial Results

Houston, Texas, May 8, 2023 – Talos Energy Inc. (“Talos” or the “Company”) (NYSE: TALO) today announced its operational and financial results for three months ended March 31, 2023. Additionally, the Company has updated its full year 2023 guidance as described further below.

Key Highlights:

- Authorized a \$100.0 million share repurchase program in March 2023 and repurchased 1.9 million shares through the end of the first quarter.
- Executed a 21,000-acre onshore CO₂ sequestration lease near the Company’s River Bend CCS project, bringing total acreage within the Baton Rouge/New Orleans region to approximately 110,000 gross acres under lease or right of first refusal.
- Announced that the Company is exploring a capital raise in the near term to finance the accelerated growth of its Talos Low Carbon Solutions (“TLCS”) platform.
- Completed the acquisition of EnVen and progressed integration activities; synergy capture estimates are on track to meet or exceed the previously guided annual \$30 million.
- Submitted the Zama Unit Development Plan for formal approval and formed an Integrated Project Team (“IPT”) to manage the development and operation of Zama going forward.

First Quarter Summary:

- Production of 63.6 thousand barrels of oil equivalent per day (“MBoe/d”) (72% oil, 79% liquids), inclusive of a partial quarter of production from the acquisition of EnVen Energy Corporation (“EnVen”).
- Revenue of \$322.6 million, driven by realized prices (excluding hedges) of \$71.28 per barrel for oil, \$22.62 per barrel for natural gas liquids (“NGLs”), and \$2.83 per thousand cubic feet (“Mcf”) for natural gas.
- Net Income of \$89.9 million, or \$0.84 Net Income per diluted share, and Adjusted Net Loss⁽¹⁾ of \$1.3 million, or \$0.01 Adjusted Net Loss per diluted share.
- Adjusted EBITDA⁽¹⁾ of \$203.1 million, or \$35.48 Adjusted EBITDA per Boe, inclusive of \$6.2 million of TLCS expenses.
- Upstream Capital Expenditures of \$190.0 million, inclusive of plugging and abandonment. Capital investments in Carbon Capture & Sequestration (“CCS”), totaled an additional \$21.2 million.

Talos President and Chief Executive Officer Timothy S. Duncan commented: “Although we have encountered several operational challenges in recent weeks, we remain focused on the totality of our 2023 plan, which positions the business for long-term growth and value creation. We are seeing our capital and operating expenses trending below our plan and we will look to continue this trend while also progressing our Venice and Lime Rock discoveries to first production. We expect that production will exceed a rate of 80 MBoe/d early in 2024, and we continue to expect to achieve our 2024 – 2026 production and cash flow goals.”

Duncan continued: “We are also making strong progress on several key projects in our business that underpin expanded shareholder value. We recently submitted the field development plan for Zama and announced an Integrated Project Team that will allow for better collaboration and execution on this world class project. In the deepwater Gulf of Mexico, we are currently drilling our high-impact Pancheron prospect, we expanded our inventory by acquiring 23,000 gross acres in the recent federal lease sale, and we completed another 23,000 acre trade that secured a high impact prospect named Daenerys, which is expected to commence drilling in 2024. In our CCS business, we more than doubled our storage capacity in multiple transactions in the first quarter and are preparing our first stratigraphic test well, leading us toward our goal of filing multiple Class VI permits in 2023. With the level of investor demand for CCS exposure, we believe a well-structured capital raise could potentially help accelerate the growth of the business in this critical phase. Lastly, we initiated our first share buyback program, and we will continue to be opportunistic with that program, which underscores our confidence on our long-term vision for the Company.”

RECENT DEVELOPMENTS AND OPERATIONS UPDATE

Shareholder Return Program: In March 2023, Talos announced a \$100 million common stock repurchase program, the first shareholder return program in the Company's history. As of March 31, 2023, the Company has repurchased 1.9 million shares, or 1.5% of the total outstanding shares, for \$26.6 million.

Zama Development Plan & IPT: In March 2023, the Zama Unit Development Plan was submitted to Mexico's National Commission of Hydrocarbons for formal approval. Additionally, an IPT comprised of representatives from all four Zama Unit Holders was established to manage the development and operation of Zama going forward. Talos will co-lead the planning, drilling, construction, and completion of all Zama wells and the planning, execution, and delivery of Zama's offshore infrastructure.

Drilling and Completion Updates:

Rigolets: Talos drilled the Rigolets exploitation prospect in the second quarter of 2023 and encountered non-commercial quantities of hydrocarbons in the well. Talos has now completed plugging and abandonment operations. Talos held a 60% working interest.

Pancheron: Talos is participating in the potentially high-impact Pancheron exploration prospect, which spud in late April 2023 following the completion of an eight-block swap in the Green Canyon and Walker Ridge areas in 2022. Talos holds a 30% working interest, bp holds a 33% working interest and Oxy holds a 37% working interest and is the operator. Results are expected around mid-year 2023.

Daenerys: In April 2023, Talos completed a farm-in transaction to combine approximately 23,000 gross acres in the Walker Ridge area with co-owners Red Willow Offshore LLC and Houston Energy LP. Talos will be the operator and plans to drill the Daenerys exploration well in the second half of 2024. The high-impact, subsalt project will evaluate the Miocene section with a gross unrisks recoverable resource potential between 100 – 300 MMBoe. Talos expects a target working interest of 30% in the initial test well.

Lease Sale 259: Talos was the apparent high bidder on four deepwater lease blocks in the Green Canyon and Mississippi Canyon areas, collectively representing over 23,000 gross acres with multiple potential future drilling prospects.

TLCS Updates:

East Louisiana Acreage Expansion: Talos executed lease agreements on private land in the first quarter of 2023 for more than 21,000 acres, nearly doubling the acreage under lease in the Baton Rouge / New Orleans, Louisiana industrial corridor and increasing the estimated gross prospective storage resource by more than 120 million metric tons of CO₂. The region now holds a gross acreage footprint of approximately 110,000 acres under lease or right of first refusal, with over 620 million metric tons of gross prospective storage resource proximal to 80 million metric tons per year of existing industrial emissions along the Mississippi River corridor.

Chevron Transaction: In March 2023, Bayou Bend CCS, a carbon capture and sequestration project located along the Texas Gulf Coast, expanded its storage footprint through the acquisition of nearly 100,000 onshore acres in Chambers and Jefferson Counties, Texas located in the Houston Ship Channel and Beaumont and Port Arthur region. The expanded Bayou Bend CCS project now encompasses nearly 140,000 acres of offshore and onshore pore space for permanent CO₂ sequestration. The total acreage holds more than one billion metric tons of gross prospective storage resource, positioning Bayou Bend CCS to be a leading carbon transportation and storage solutions for industrial emitters in one of the largest industrial corridors of the country. Equity interests in Bayou Bend CCS remain 50 percent Chevron Corporation ("Chevron"), 25 percent Talos, and 25 percent Carbonvert Inc. Effective March 1, 2023, Chevron became the operator of Bayou Bend CCS.

Class VI Permit Application Progress: The Bayou Bend partnership has contracted a rig and expects to drill an offshore stratigraphic data collection well in the state waters off Jefferson County, Texas, during the third quarter. TLCS is also acquiring and analyzing data across several projects with plans to file two to three EPA Class VI permit applications by year-end.

GUIDANCE UPDATES

Full-Year 2023 Production Guidance:

Talos now expects average daily production for the full year 2023 to be in the range of 66.0 to 71.0 MBoe/d. While production results for January and February of 2023 were in-line with original management expectations for both Talos and EnVen, delays in first production from new wells, certain underperformance, and unplanned downtime now forecasted for the remainder of the year have led to re-guiding the Company's 2023 production, with the following details:

Recent Drilling Program Updates: Recent production levels from selected new wells are below expected pre-drill contributions for the year, amounting to an expected impact of 2.0 – 3.0 MBoe/d as compared to original guidance, primarily due to delays in first production and lower than expected initial production rates from the Bulleit and Mt. Hunter wells. The Company is planning a well intervention in Bulleit in the second quarter to attempt to access production from a lower completion.

Selected Well Underperformance: Certain existing wells exhibited production rate declines earlier than planned, generating a 2023 production impact of 1.0 – 2.0 MBoe/d as compared to original guidance. Most notably, this includes two non-operated Shelf wells that began experiencing production declines due to earlier-than-expected water production.

Unplanned Downtime: Despite diagnostic and corrective operations in the fourth quarter of 2022 and the first quarter of 2023, Talos expects its operated Neptune facility to require intermittent production shut-ins resulting in a full-year 2023 production impact of 1.0 – 1.5 MBoe/d as compared to original guidance while Talos works to optimize flow assurance of the subsea system in the field.

		Original		Revised	
		Low	High	Low	High
Production	Oil (MMBbl)	19.2	20.3	17.6	18.9
	Natural Gas (Mcf)	32.2	33.8	29.3	31.6
	NGL (MMBbl)	1.7	1.8	1.6	1.8
	Total Production (MMBoe)	26.3	27.7	24.1	25.9
	Avg Daily Production (MBoe/d)	72.0	76.0	66.0	71.0

Full-Year 2023 Expense Guidance:

All previously guided expense categories remain unchanged from prior guidance.

		Original (Reaffirmed)	
		Low	High
<i>(\$ Millions):</i>			
Cash Expenses	Cash Operating Expenses ⁽¹⁾⁽²⁾⁽⁴⁾	\$ 410	\$ 430
	G&A ⁽²⁾⁽³⁾	\$ 90	\$ 95
Capex	Upstream Capital Expenditures ⁽⁵⁾	\$ 650	\$ 675
CCS Investments	CCS Expenses & Capex ⁽⁶⁾⁽⁸⁾	\$ 70	\$ 90
P&A Expenditures	Plugging & Abandonment, Settlement of Decommissioning Obligations	\$ 75	\$ 85
Interest	Interest Expense ⁽⁷⁾	\$ 155	\$ 165

(1) Inclusive of all Lease Operating Expenses and Workover and Maintenance.

(2) Includes insurance costs.

(3) Excludes non-cash equity-based compensation.

(4) Includes reimbursements under production handling agreements.

(5) Excludes acquisitions.

(6) Excludes future acquisitions. Cash contributions to Bayou Bend CCS for the acquisition of additional acreage is included in 2023 guidance.

(7) Includes cash interest expense on debt and finance lease, surety charges, amortization of deferred financing costs and original issue discounts.

(8) Includes CCS-specific G&A costs.

Note: Due to the forward-looking nature a reconciliation of Cash Operating Expenses and G&A to the most directly comparable GAAP measure could not be reconciled without unreasonable efforts.

FIRST QUARTER 2023 RESULTS

Key Financial Highlights:

<i>(\$ thousands):</i>	Three Months Ended March 31, 2023
Total revenues	\$ 322,582
Net income	\$ 89,860
Net income per diluted share	\$ 0.84
Adjusted Net Loss ⁽¹⁾	\$ (1,255)
Adjusted Net Loss per diluted share ⁽¹⁾	\$ (0.01)
Adjusted EBITDA ⁽¹⁾	\$ 203,063
Adjusted EBITDA excluding hedges ⁽¹⁾	\$ 215,386
Upstream Capital Expenditures (including Plug & Abandonment)	\$ 190,024
<i>Adjusted EBITDA Margin:</i>	
Adjusted EBITDA per Boe	\$ 35.48
Adjusted EBITDA excluding hedges per Boe	\$ 37.64

Production

Production was 63.6 MBoe/d net for the first quarter 2023 and was 72% oil and 79% liquids. Production figures are inclusive of the EnVen assets from the closing date of February 13, 2023 through the end of the quarter.

	Three Months Ended March 31, 2023
Average net daily production volumes	
Oil (MBbl/d)	45.6
Natural Gas (MMcf/d)	79.2
NGL (MBbl/d)	4.8
Total average net daily (MBoe/d)	63.6

	Three Months Ended March 31, 2023			
	Production	% Oil	% Liquids	% Operated
Average net daily production volumes by Core Area (MBoe/d)				
Green Canyon Area	23.9	82%	88%	92%
Mississippi Canyon Area	25.2	78%	86%	60%
Shelf and Gulf Coast	14.5	45%	54%	60%
Total average net daily (MBoe/d)	<u>63.6</u>	72%	79%	72%

Capital Expenditures

Upstream capital expenditures, including plugging and abandonment, totaled \$190.0 million for the first quarter 2023.

	Three Months Ended March 31, 2023
Upstream Capital Expenditures	
U.S. drilling & completions	\$ 112,330
Mexico appraisal & exploration	96
Asset management ⁽¹⁾	44,944
Seismic and G&G, land, capitalized G&A and other	21,833
Total Upstream Capital Expenditures	179,203
Plugging & Abandonment	10,113
Decommissioning Obligations Settled ⁽²⁾	708
Total	<u>\$ 190,024</u>

(1) Asset management consists of capital expenditures for development-related activities primarily associated with recompletions and improvements to our facilities and infrastructure.

(2) Settlement of decommissioning obligations as a result of working interest partners or counterparties of divestiture transactions that were unable to perform the required abandonment obligations due to bankruptcy or insolvency.

CCS expenses totaled \$6.2 million, which is accounted for in the Company’s reported Adjusted EBITDA figure. CCS capital expenditures totaled \$21.2 million, which includes our investments in recent Bayou Bend and eastern Louisiana acreage expansions.

<i>(\$ Millions):</i>	Three Months Ended March 31, 2023
CCS Investments	
CCS Expenses	\$ 6,157
CCS Capital Expenditures	21,189
Total CCS Investments	\$ 27,346

Liquidity and Leverage

At quarter-end, the Company had approximately \$805.4 million of liquidity, with \$800.0 million undrawn on its credit facility and approximately \$16.2 million in cash, less approximately \$10.8 million in outstanding letters of credit.

On March 31, 2023, Talos had \$1,061.0 million in total debt. Net Debt was \$1,044.9 million⁽¹⁾. Net Debt to Pro Forma LTM Adjusted EBITDA was 0.9x⁽¹⁾. In conjunction with the closing of the EnVen acquisition on February 13, 2023, Talos drew approximately \$130.0 million on its credit facility and assumed EnVen’s previously issued and outstanding 11.75% second priority senior secured notes.

Footnotes:

- (1) Adjusted Net Income (Loss), Adjusted Earnings (Loss) per Share, Adjusted EBITDA, Adjusted EBITDA excluding hedges, Adjusted EBITDA margin, Adjusted EBITDA margin excluding hedges, Credit Facility LTM Adjusted EBITDA, Net Debt, Net Debt to Credit Facility LTM Adjusted EBITDA, Adjusted Free Cash Flow and PV-10 are non-GAAP financial measures. See “Supplemental Non-GAAP Information” below for additional detail and reconciliations of GAAP to non-GAAP measures.

HEDGES

The following table reflects contracted volumes and weighted average prices the Company will receive under the terms of its derivative contracts as of May 8, 2023:

	Instrument Type	Avg. Daily Volume	W.A. Swap	W.A. Sub-Floor	W.A. Floor	W.A. Ceiling
		(Bbls)	(Per Bbl)	(Per Bbl)	(Per Bbl)	(Per Bbl)
Crude – WTI						
April - June 2023	Fixed Swaps	27,000	\$ 74.12			
April - June 2023	Collar	2,500			\$ 65.00	\$ 89.22
April - June 2023	3-Way Collar	9,200		\$ 51.32	\$ 64.57	\$ 108.63
July - September 2023	Fixed Swaps	14,348	\$ 73.92			
July - September 2023	Collar	4,500			\$ 70.56	\$ 89.99
July - September 2023	3-Way Collar	9,200		\$ 51.86	\$ 65.11	\$ 109.25
October - December 2023	Fixed Swaps	12,000	\$ 75.25			
October - December 2023	Collar	7,826			\$ 67.76	\$ 86.40
October - December 2023	3-Way Collar	9,200		\$ 51.86	\$ 65.11	\$ 109.25
January - March 2024	Fixed Swaps	15,000	\$ 72.55			
January - March 2024	Collar	3,000			\$ 70.00	\$ 83.67
January - March 2024	3-Way Collar	3,200		\$ 57.27	\$ 70.00	\$ 98.01
April - June 2024	Fixed Swaps	13,500	\$ 74.15			
April - June 2024	Collar	1,000			\$ 70.00	\$ 75.00
July - September 2024	Fixed Swaps	8,000	\$ 72.53			
July - September 2024	Collar	1,000			\$ 70.00	\$ 75.00
October - December 2024	Fixed Swaps	7,000	\$ 70.68			
October - December 2024	Collar	1,000			\$ 70.00	\$ 75.00
January - March 2025	Fixed Swaps	4,000	\$ 67.00			
Natural Gas – HH NYMEX						
		(MMBtu)	(Per MMBtu)	(Per MMBtu)	(Per MMBtu)	(Per MMBtu)
April - June 2023	Fixed Swaps	39,000	\$ 3.33			
April - June 2023	Collar	10,000			\$ 5.25	\$ 8.46
July - September 2023	Fixed Swaps	20,000	\$ 3.35			
July - September 2023	Collar	10,000			\$ 5.25	\$ 8.46
October - December 2023	Fixed Swaps	20,000	\$ 4.22			
October - December 2023	Collar	10,000			\$ 5.25	\$ 8.46
January - March 2024	Fixed Swaps	25,000	\$ 3.48			
January - March 2024	Collar	10,000			\$ 4.00	\$ 6.90
April - June 2024	Fixed Swaps	20,000	\$ 3.38			
April - June 2024	Collar	10,000			\$ 4.00	\$ 6.90
July - September 2024	Fixed Swaps	10,000	\$ 3.52			
July - September 2024	Collar	10,000			\$ 4.00	\$ 6.90
October - December 2024	Fixed Swaps	10,000	\$ 3.52			
October - December 2024	Collar	10,000			\$ 4.00	\$ 6.90
January - March 2025	Fixed Swaps	10,000	\$ 4.37			

CONFERENCE CALL AND WEBCAST INFORMATION

Talos will host a conference call, which will be broadcast live over the internet, on Tuesday, May 9, 2023 at 10:00 AM Eastern Time (9:00 AM Central Time). Listeners can access the conference call through a webcast link on the Company's website at: <https://www.talosenergy.com/investor-relations/events-calendar/default.aspx>. Alternatively, the conference call can be accessed by dialing (888) 348-8927 (U.S. toll-free), (855) 669-9657 (Canada toll-free) or (412) 902-4263 (international). Please dial in approximately 15 minutes before the teleconference is scheduled to begin and ask to be joined into the Talos Energy call. A replay of the call will be available one hour after the conclusion of the conference until May 16, 2023 and can be accessed by dialing (877) 344-7529 and using access code 4517185.

ABOUT TALOS ENERGY

Talos Energy (NYSE: TALO) is a technically driven independent exploration and production company focused on safely and efficiently maximizing long-term value through its operations, currently in the United States and offshore Mexico, both upstream through oil and gas exploration and production and downstream through the development of future carbon capture and storage opportunities. As one of the Gulf of Mexico's largest public independent producers, we leverage decades of technical and offshore operational expertise towards the acquisition, exploration and development of assets in key geological trends that are present in many offshore basins around the world. With a focus on environmental stewardship, we are also utilizing our expertise to explore opportunities to reduce industrial emissions through our carbon capture and storage initiatives along the U.S. Gulf of Mexico. For more information, visit www.talosenergy.com.

INVESTOR RELATIONS CONTACT

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

This communication may contain “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical fact included in this communication, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this communication, the words “will,” “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project,” “forecast,” “may,” “objective,” “plan” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events.

We caution you that these forward-looking statements are subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks include, but are not limited to, the anticipated future integration of the assets acquired from EnVen Energy Corporation; the success of our carbon capture and sequestration projects; commodity price volatility; the lack of a resolution to the war in Ukraine and its impact on certain commodity markets; the ability or willingness of the Organization of Petroleum Exporting Countries (“OPEC”) and non-OPEC countries, such as Saudi Arabia and Russia, to set and maintain oil production levels and the impact of any such actions; the success of any future capital raise; the impact of the ongoing sub-surface water flood project in the Phoenix Field and any updates to our estimated ultimate recovery from such project; lack of transportation and storage capacity as a result of oversupply, government regulations and actions or other factors; sustained inflation and the impact of central bank policy in response thereto; lack of availability of drilling and production equipment and services; environmental risks; drilling and other operating risks; regulatory changes; adverse weather events, including tropical storms, hurricanes and winter storms; cybersecurity threats; the continued impact of the coronavirus disease 2019 (“COVID-19”), including any new strains or variants, and governmental measures related thereto; the uncertainty inherent in estimating reserves and in projecting future rates of production, cash flow and access to capital; the timing of development expenditures; the possibility that the anticipated benefits of recent acquisitions are not realized when expected or at all, including as a result of the impact of, or problems arising from, the integration of such acquisitions; changes to federal income tax laws and regulations, including the Inflation Reduction Act of 2022; environmental risks; failure to find, acquire or gain access to other discoveries and prospects or to successfully develop and produce from our current discoveries and prospects; geologic risk; drilling and other operating risks; well control risk; regulatory changes; the uncertainty inherent in estimating reserves and in projecting future rates of production; cash flow and access to capital; the timing of development expenditures; potential adverse reactions or competitive responses to our acquisitions and other transactions; the possibility that the anticipated benefits of our acquisitions are not realized when expected or at all, including as a result of the impact of, or problems arising from, the integration of acquired assets and operations, and the other risks discussed in Part I, Item 1A. “Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2022, filed with the SEC on March 1, 2023 and Part II, Item 1A. “Risk Factors” in our Annual Report on Form 10-Q for the quarter ended March 31, 2023, filed subsequent to the issuance of this communication.

Should one or more of the risks or uncertainties described herein occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements, expressed or implied, included in this communication are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue. Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this communication.

Estimates for our future production volumes are based on assumptions of capital expenditure levels and the assumption that market demand and prices for oil and gas will continue at levels that allow for economic production of these products. The production, transportation, marketing and storage of oil and gas are subject to disruption due to transportation, processing and storage availability, mechanical failure, human error, hurricanes and numerous other factors. Our estimates are based on certain other assumptions, such as well performance, which may vary significantly from those assumed. Therefore, we can give no assurance that our future production volumes will be as estimated.

RESERVE INFORMATION

Reserve engineering is a process of estimating underground accumulations of oil, natural gas and NGLs that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions upward or downward of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil, natural gas and NGLs that are ultimately recovered. In addition, we use the term “gross unrisks resource potential” in this release, which is not a measure of “reserves” prepared in accordance with SEC guidelines or permitted to be included in SEC filings. These resource estimates are inherently more uncertain than estimates of reserves prepared in accordance with SEC guidelines.

Talos Energy Inc.
Condensed Consolidated Balance Sheets
(In thousands, except per share amounts)

	March 31, 2023	December 31, 2022
	(Unaudited)	
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 16,169	\$ 44,145
Accounts receivable:		
Trade, net	169,850	150,598
Joint interest, net	80,549	54,697
Other, net	17,954	6,684
Assets from price risk management activities	54,553	25,029
Prepaid assets	60,127	84,759
Other current assets	11,901	1,917
Total current assets	411,103	367,829
Property and equipment:		
Proved properties	7,368,652	5,964,340
Unproved properties, not subject to amortization	410,932	154,783
Other property and equipment	31,485	30,691
Total property and equipment	7,811,069	6,149,814
Accumulated depreciation, depletion and amortization	(3,653,556)	(3,506,539)
Total property and equipment, net	4,157,513	2,643,275
Other long-term assets:		
Restricted cash	100,973	—
Assets from price risk management activities	12,059	7,854
Equity method investments	22,023	1,745
Other well equipment inventory	40,345	25,541
Notes receivable, net	15,031	—
Operating lease assets	18,572	5,903
Other assets	18,136	6,479
Total assets	\$ 4,795,755	\$ 3,058,626
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	\$ 184,471	\$ 128,174
Accrued liabilities	201,360	219,769
Accrued royalties	44,340	52,215
Current portion of long-term debt	33,201	—
Current portion of asset retirement obligations	45,592	39,888
Liabilities from price risk management activities	35,848	68,370
Accrued interest payable	31,210	36,340
Current portion of operating lease liabilities	3,129	1,943
Other current liabilities	92,041	60,359
Total current liabilities	671,192	607,058
Long-term liabilities:		
Long-term debt	977,011	585,340
Asset retirement obligations	772,059	501,773
Liabilities from price risk management activities	4,286	7,872
Operating lease liabilities	25,981	14,855
Other long-term liabilities	284,385	176,152
Total liabilities	2,734,914	1,893,050
Commitments and contingencies		
Stockholders' equity:		
Preferred stock; \$0.01 par value; 30,000,000 shares authorized and zero shares issued or outstanding as of March 31, 2023 and December 31, 2022	—	—
Common stock; \$0.01 par value; 270,000,000 shares authorized; 127,455,965 and 82,570,328 shares issued as of March 31, 2023 and December 31, 2022, respectively	1,275	826
Additional paid-in capital	2,531,402	1,699,799
Accumulated deficit	(445,189)	(535,049)
Treasury stock, at cost; 1,900,000 and zero shares as of March 31, 2023 and December 31, 2022, respectively	(26,647)	—
Total stockholders' equity	2,060,841	1,165,576
Total liabilities and stockholders' equity	\$ 4,795,755	\$ 3,058,626

Talos Energy Inc.
Condensed Consolidated Statements of Operations
(In thousands, except per share amounts)

	Three Months Ended March 31,	
	2023	2022
Revenues:		
Oil	\$ 292,694	\$ 353,886
Natural gas	20,183	42,981
NGL	9,705	16,699
Total revenues	322,582	413,566
Operating expenses:		
Lease operating expense	81,362	59,814
Production taxes	606	851
Depreciation, depletion and amortization	147,323	98,340
Accretion expense	19,414	14,377
General and administrative expense	63,187	22,528
Other operating expense	2,838	136
Total operating expenses	314,730	196,046
Operating income	7,852	217,520
Interest expense	(37,581)	(31,490)
Price risk management activities income (expense)	58,937	(281,219)
Equity method investment income	7,443	142
Other income	6,666	28,134
Net income (loss) before income taxes	43,317	(66,913)
Income tax benefit	46,543	472
Net income (loss)	\$ 89,860	\$ (66,441)
Net income (loss) per common share:		
Basic	\$ 0.85	\$ (0.81)
Diluted	\$ 0.84	\$ (0.81)
Weighted average common shares outstanding:		
Basic	105,634	82,071
Diluted	106,950	82,071

Talos Energy Inc.
Condensed Consolidated Statements of Cash Flows
(In thousands)

	Three Months Ended March 31,	
	2023	2022
Cash flows from operating activities:		
Net income (loss)	\$ 89,860	\$ (66,441)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion expense	166,737	112,717
Amortization of deferred financing costs and original issue discount	4,148	3,415
Equity-based compensation expense	3,938	3,318
Price risk management activities expense (income)	(58,937)	281,219
Net cash paid on settled derivative instruments	(12,323)	(127,086)
Equity method investment income	(7,443)	(142)
Settlement of asset retirement obligations	(10,113)	(20,023)
Changes in operating assets and liabilities:		
Accounts receivable	36,821	(56,817)
Other current assets	7,735	4,505
Accounts payable	(4,894)	9,381
Other current liabilities	(116,637)	(26,423)
Other non-current assets and liabilities, net	(36,035)	(4,013)
Net cash provided by operating activities	62,857	113,610
Cash flows from investing activities:		
Exploration, development and other capital expenditures	(103,962)	(53,978)
Proceeds from (payments for) acquisitions, net of cash acquired	17,617	(3,500)
Proceeds from sale of property and equipment, net	—	346
Contributions to equity method investees	(12,835)	(2,250)
Investment in intangible assets	(7,796)	—
Net cash used in investing activities	(106,976)	(59,382)
Cash flows from financing activities:		
Proceeds from Bank Credit Facility	275,000	35,000
Repayment of Bank Credit Facility	(110,000)	(70,000)
Deferred financing costs	(11,346)	—
Payments of finance lease	(3,987)	(6,256)
Purchase of treasury stock	(25,173)	—
Employee stock awards tax withholdings	(7,378)	(4,476)
Net cash provided by (used in) financing activities	117,116	(45,732)
Net increase in cash, cash equivalents and restricted cash	72,997	8,496
Cash, cash equivalents and restricted cash:		
Balance, beginning of period	44,145	69,852
Balance, end of period	\$ 117,142	\$ 78,348
Supplemental non-cash transactions:		
Capital expenditures included in accounts payable and accrued liabilities	\$ 174,597	\$ 53,317
Supplemental cash flow information:		
Interest paid, net of amounts capitalized	\$ 40,988	\$ 43,352

SUPPLEMENTAL NON-GAAP INFORMATION

Certain financial information included in our financial results are not measures of financial performance recognized by accounting principles generally accepted in the United States, or GAAP. These non-GAAP financial measures are “Adjusted Net Income (Loss),” “Adjusted Earnings per Share,” “EBITDA,” “Adjusted EBITDA,” “Adjusted EBITDA excluding hedges,” “Adjusted EBITDA Margin,” “Adjusted EBITDA Margin excluding hedges,” “Adjusted Free Cash Flow,” “Net Debt,” “LTM Adjusted EBITDA,” “Credit Facility LTM Adjusted EBITDA,” “Net Debt to Credit Facility LTM Adjusted EBITDA” and “PV-10.” These disclosures may not be viewed as a substitute for results determined in accordance with GAAP and are not necessarily comparable to non-GAAP measures which may be reported by other companies.

Reconciliation of Net Income (Loss) to EBITDA and Adjusted EBITDA

“EBITDA” and “Adjusted EBITDA” are to provide management and investors with (i) additional information to evaluate, with certain adjustments, items required or permitted in calculating covenant compliance under our debt agreements, (ii) important supplemental indicators of the operational performance of our business, (iii) additional criteria for evaluating our performance relative to our peers and (iv) supplemental information to investors about certain material non-cash and/or other items that may not continue at the same level in the future. EBITDA and Adjusted EBITDA have limitations as analytical tools and should not be considered in isolation or as substitutes for analysis of our results as reported under GAAP or as alternatives to net income (loss), operating income (loss) or any other measure of financial performance presented in accordance with GAAP. We define these as the following:

EBITDA. Net income (loss) plus interest expense, income tax expense (benefit), depreciation, depletion and amortization and accretion expense.

Adjusted EBITDA. EBITDA plus non-cash write-down of oil and natural gas properties, transaction and other (income) expenses, decommissioning obligations, derivative fair value (gain) loss, net cash receipts (payments) on settled derivatives, (gain) loss on debt extinguishment, non-cash write-down of other well equipment inventory and non-cash equity-based compensation expense.

Adjusted EBITDA excluding hedges. We have historically provided as a supplement to—rather than in lieu of—Adjusted EBITDA including hedges, provides useful information regarding our results of operations and profitability by illustrating the operating results of our oil and natural gas properties without the benefit or detriment, as applicable, of our financial oil and natural gas hedges. By excluding our oil and natural gas hedges, we are able to convey actual operating results using realized market prices during the period, thereby providing analysts and investors with additional information they can use to evaluate the impacts of our hedging strategies over time.

We also present Adjusted EBITDA excluding hedges and as a percentage of revenue to further analyze our business, which are outlined below:

Adjusted EBITDA Margin. EBITDA divided by Revenue, as a percentage. It is also defined as Adjusted EBITDA divided by the total production volume, expressed in Boe, in the period, and described as dollar per Boe. We believe the presentation of Adjusted EBITDA margin is important to provide management and investors with information about how much we retain in Adjusted EBITDA terms as compared to the revenue we generate and how much per barrel we generate after accounting for certain operational and corporate costs.

The following table presents a reconciliation of the GAAP financial measure of net income (loss) to EBITDA, Adjusted EBITDA, Adjusted EBITDA excluding hedges, Adjusted EBITDA Margin and Adjusted EBITDA Margin excluding hedges for each of the periods indicated (in thousands, except for Boe, \$/Boe and percentage data):

	Three Months Ended			
	March 31, 2023	December 31, 2022	September 30, 2022	June 30, 2022
<i>(\$ thousands, except per Boe)</i>				
Reconciliation of net income (loss) to Adjusted EBITDA:				
Net Income (loss)	\$ 89,860	\$ 2,750	\$ 250,465	\$ 195,141
Interest expense	37,581	33,967	29,265	30,776
Income tax expense (benefit)	(46,543)	281	121	2,607
Depreciation, depletion and amortization	147,323	119,456	92,323	104,511
Accretion expense	19,414	13,595	13,179	14,844
EBITDA	247,635	170,049	385,353	347,879
Transaction and other (income) expenses ⁽¹⁾	22,009	4,343	3,219	(15,214)
Decommissioning obligations ⁽²⁾	741	21,005	20	10,204
Derivative fair value (gain) loss ⁽³⁾	(58,937)	41,058	(114,180)	64,094
Net cash payments on settled derivative instruments ⁽³⁾	(12,323)	(57,076)	(81,162)	(160,235)
Loss on extinguishment of debt	—	1,569	—	—
Non-cash equity-based compensation expense	3,938	4,276	4,310	4,049
Adjusted EBITDA	203,063	185,224	197,560	250,777
Add: Net cash payments on settled derivative instruments ⁽³⁾	12,323	57,076	81,162	160,235
Adjusted EBITDA excluding hedges	<u>\$ 215,386</u>	<u>\$ 242,300</u>	<u>\$ 278,722</u>	<u>\$ 411,012</u>
Production and Revenue:				
Boe ⁽⁴⁾	5,723	5,207	4,876	5,953
Total revenues	322,582	342,201	377,128	519,085
Adjusted EBITDA margin and Adjusted EBITDA excl hedges margin:				
Adjusted EBITDA divided by – Total revenues incl hedges (%)	65%	65%	67%	70%
Adjusted EBITDA per Boe ⁽⁴⁾	\$ 35.48	\$ 35.57	\$ 40.52	\$ 42.13
Adjusted EBITDA excl hedges divided by – Total revenues (%)	67%	71%	74%	79%
Adjusted EBITDA excl hedges per Boe ⁽³⁾	\$ 37.64	\$ 46.53	\$ 57.16	\$ 69.04

- (1) For the three months ended March 31, 2023, transaction expenses include \$35.2 million in costs related to the EnVen Acquisition, inclusive of \$22.6 million in severance expense. Other income (expense) includes other miscellaneous income and expenses that we do not view as a meaningful indicator of our operating performance. For the three months ended March 31, 2023, it includes a \$8.6 million gain on the funding of the capital carry of its investment in Bayou Bend by Chevron. For the three months ended June 30, 2022, it includes a \$13.9 million gain on partial sale of our investment in Bayou Bend.
- (2) Estimated decommissioning obligations were a result of working interest partners or counterparties of divestiture transactions that were unable to perform the required abandonment obligations due to bankruptcy or insolvency.
- (3) The adjustments for the derivative fair value (gain) loss and net cash receipts (payments) on settled derivative instruments have the effect of adjusting net income (loss) for changes in the fair value of derivative instruments, which are recognized at the end of each accounting period because we do not designate commodity derivative instruments as accounting hedges. This results in reflecting commodity derivative gains and losses within Adjusted EBITDA on an unrealized basis during the period the derivatives settled.
- (4) One Boe is equal to six Mcf of natural gas or one Bbl of oil or NGLs based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

Reconciliation of Adjusted EBITDA to Adjusted Free Cash Flow and Reconciliation of Net Cash Provided by Operating Activities to Adjusted Free Cash Flow

“Adjusted Free Cash Flow” before changes in working capital provides management and investors with (i) important supplemental indicators of the operational performance of our business, (ii) additional criteria for evaluating our performance relative to our peers and (iii) supplemental information to investors about certain material non-cash and/or other items that may not continue at the same level in the future. Adjusted Free Cash Flow has limitations as an analytical tool and should not be considered in isolation or as substitutes for analysis of our results as reported under GAAP or as alternatives to net income (loss), operating income (loss) or any other measure of financial performance presented in accordance with GAAP. We define these as the following:

Capital Expenditures and Plugging & Abandonment. Actual capital expenditures and plugging & abandonment recognized in the quarter, inclusive of accruals.

Interest Expense. Actual interest expense per the income statement.

Talos did not pay any cash taxes in the period, therefore cash taxes have no impact to the reported Adjusted Free Cash Flow before changes in working capital number.

<i>(\$ thousands)</i>	Three Months Ended March 31, 2023
Reconciliation of Adjusted EBITDA to Adjusted Free Cash Flow (before changes in working capital)	
Adjusted EBITDA	\$ 203,063
Less: Upstream capital expenditures	(179,203)
Less: Plugging & abandonment	(10,113)
Less: Decommissioning obligations settled	(708)
Less: CCS capital expenditures	(21,189)
Less: Interest expense	(37,581)
Adjusted Free Cash Flow (before changes in working capital)	<u>\$ (45,731)</u>

<i>(\$ thousands)</i>	Three Months Ended March 31, 2023
Reconciliation of net cash provided by operating activities to Adjusted Free Cash Flow (before changes in working capital)	
Net cash provided by operating activities ⁽¹⁾	\$ 62,857
(Increase) decrease in operating assets and liabilities	113,010
Upstream capital expenditures ⁽²⁾	(179,203)
Decommissioning obligations settled	(708)
CCS capital expenditures	(21,189)
Transaction and other (income) expenses ⁽³⁾	30,597
Decommissioning obligations ⁽⁴⁾	741
Amortization of deferred financing costs and original issue discount	(4,148)
Income tax benefit	(46,543)
Other adjustments	(1,145)
Adjusted Free Cash Flow (before changes in working capital)	<u>\$ (45,731)</u>

(1) Includes settlement of asset retirement obligations.

(2) Includes accruals and excludes acquisitions.

(3) For the three months ended March 31, 2023, transaction expenses include \$35.2 million in costs related to the EnVen Acquisition, inclusive of \$22.6 million in severance expense. Other income (expenses) includes miscellaneous income and expenses that we do not view as a meaningful indicator of our operating performance.

(4) Estimated decommissioning obligations were a result of working interest partners or counterparties of divestiture transactions that were unable to perform the required abandonment obligations due to bankruptcy or insolvency.

Reconciliation of Net Income to Adjusted Net Income (Loss) and Adjusted Earnings per Share

“Adjusted Net Income (Loss)” and “Adjusted Earnings per Share” are to provide management and investors with (i) important supplemental indicators of the operational performance of our business, (ii) additional criteria for evaluating our performance relative to our peers and (iii) supplemental information to investors about certain material non-cash and/or other items that may not continue at the same level in the future. Adjusted Net Income (Loss) and Adjusted Earnings per Share have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP or as an alternative to net income (loss), operating income (loss), earnings per share or any other measure of financial performance presented in accordance with GAAP.

Adjusted Net Income (Loss). Net income (loss) plus accretion expense, transaction related costs, derivative fair value (gain) loss, net cash receipts (payments) on settled derivative instruments and non-cash equity-based compensation expense.

Adjusted Earnings per Share. Adjusted Net Income (Loss) divided by the number of common shares.

(\$ thousands, except per share amounts)	Three Months Ended March 31, 2023			
			Basic per Share	Diluted per Share
Reconciliation of Net Income to Adjusted Net Loss:				
Net Income	\$	89,860	\$ 0.85	\$ 0.84
Transaction and other (income) expenses ⁽¹⁾		22,009	\$ 0.21	\$ 0.21
Decommissioning obligations ⁽²⁾		741	\$ 0.01	\$ 0.01
Derivative fair value gain ⁽³⁾		(58,937)	\$(0.56)	\$(0.55)
Net cash payments on settled derivative instruments ⁽³⁾		(12,323)	\$(0.12)	\$(0.12)
Non-cash income tax expense		(46,543)	\$(0.44)	\$(0.44)
Non-cash equity-based compensation expense		3,938	\$ 0.04	\$ 0.04
Adjusted Net Loss	\$	(1,255)	\$(0.01)	\$(0.01)
Weighted average common shares outstanding at March 31, 2023:				
Basic			105,634	
Diluted			106,950	

- (1) For the three months ended March 31, 2023, transaction expenses include \$35.2 million in costs related to the EnVen Acquisition, inclusive of \$22.6 million in severance expense. Other income (expense) includes other miscellaneous income and expenses that we do not view as a meaningful indicator of our operating performance. For the three months ended March 31, 2023, it includes a \$8.6 million gain on the funding of the capital carry of its investment in Bayou Bend by Chevron.
- (2) Estimated decommissioning obligations were a result of working interest partners or counterparties of divestiture transactions that were unable to perform the required abandonment obligations due to bankruptcy or insolvency.
- (3) The adjustments for the derivative fair value (gain) loss and net cash receipts (payments) on settled derivative instruments have the effect of adjusting net income (loss) for changes in the fair value of derivative instruments, which are recognized at the end of each accounting period because we do not designate commodity derivative instruments as accounting hedges. This results in reflecting commodity derivative gains and losses within Adjusted Net Income (Loss) on an unrealized basis during the period the derivatives settled.

Reconciliation of Total Debt to Net Debt and Net Debt to LTM Adjusted EBITDA

We believe the presentation of Net Debt, LTM Adjusted EBITDA, and Net Debt to LTM Adjusted EBITDA is important to provide management and investors with additional important information to evaluate our business. These measures are widely used by investors and ratings agencies in the valuation, comparison, rating and investment recommendations of companies.

Net Debt. Total Debt principal of the Company minus cash and cash equivalents.

Net Debt to LTM Adjusted EBITDA. Net Debt divided by the LTM Adjusted EBITDA.

	<u>March 31, 2023</u>
Reconciliation of Net Debt (\$ thousands):	
12.00% Second-Priority Senior Secured Notes – due January 2026	\$ 638,541
11.75% Senior Secured Second Lien Notes – due April 2026	257,500
Bank Credit Facility – matures March 2027	165,000
Total Debt	1,061,041
Less: Cash and cash equivalents	(16,169)
Net Debt	<u>\$ 1,044,872</u>
Calculation of LTM Adjusted EBITDA:	
Adjusted EBITDA for three months period ended June 30, 2022	\$ 250,777
Adjusted EBITDA for three months period ended September 30, 2022	197,560
Adjusted EBITDA for three months period ended December 31, 2022	185,224
Adjusted EBITDA for three months period ended March 31, 2023	203,063
LTM Adjusted EBITDA	<u>\$ 836,624</u>
Acquired Assets Adjusted EBITDA:	
Adjusted EBITDA for three months period ended June 30, 2022	\$ 132,084
Adjusted EBITDA for three months period ended September 30, 2022	102,867
Adjusted EBITDA for three months period ended December 31, 2022	73,891
Adjusted EBITDA for period January 1, 2023 to February 13, 2023	33,120
LTM Adjusted EBITDA from Acquired Assets	<u>\$ 341,962</u>
Pro Forma LTM Adjusted EBITDA	<u>\$ 1,178,586</u>
Reconciliation of Net Debt to Pro Forma LTM Adjusted EBITDA:	
Net Debt / Pro Forma LTM Adjusted EBITDA ⁽¹⁾	0.9x

(1) Net Debt / Pro Forma LTM Adjusted EBITDA excludes the Finance Lease. Had the Finance Lease been included, Net Debt / Pro Forma LTM Adjusted EBITDA would have been 1.0x.