Talos Energy Announces Second Quarter 2023 Operational and Financial Results

Houston, Texas, August 8, 2023 – Talos Energy Inc. ("Talos" or the "Company") (NYSE: TALO) today announced its operational and financial results for fiscal quarter ended June 30, 2023.

Key Highlights:

- Drilled a successful commercial discovery at the Talos-operated Sunspear prospect.
- Announced a transaction with Grupo Carso, selling a 49.9% interest in Talos Energy Mexico 7, S. de R.L. de C.V. ("Talos Mexico"), a wholly-owned subsidiary of the Company, which holds a working interest in the Zama project, for approximately $125 million.
- Filed first EPA Class VI permit for carbon sequestration, with at least one additional permit expected to be filed by year-end.
- Continue to explore a capital raise for the Company's Talos Low Carbon Solutions ("TLCS") platform.
- Repurchased 1.5 million shares of common stock for $20.9 million at an average price of $13.89 per share.

Second Quarter Summary:

- Production of 70.3 thousand barrels of oil equivalent per day ("MBoe/d") (75% oil, 83% liquids).
- Revenue of $367.2 million, driven by realized prices (excluding hedges) of $71.44 per barrel for oil, $16.25 per barrel for natural gas liquids ("NGLs"), and $2.46 per thousand cubic feet ("Mcf") for natural gas.
- Net Income of $13.7 million, or $0.11 Net Income per diluted share, and Adjusted Net Income(1) of $11.5 million, or $0.09 Adjusted Net Income per diluted share.
- Upstream Adjusted EBITDA(1) of $253.6 million.
- Capital expenditures of $191.2 million, inclusive of plugging and abandonment and Carbon Capture & Sequestration ("CCS").
- Net cash provided by operating activities of $214.2 million.
- Adjusted Free Cash Flow(1) of $12.9 million.

Talos President and Chief Executive Officer Timothy S. Duncan commented: "We made great progress advancing key catalysts and had solid execution across our business in the second quarter. The ongoing integration of the EnVen transaction and our increased oil and liquids exposure underpinned another quarter with strong margins. We are excited about our discovery at Sunspear, a prospect and host facility acquired in the EnVen transaction. This success further demonstrates our belief that owning critical assets in the Gulf of Mexico can significantly enhance subsea drilling economics. We announced a transaction for our Talos Mexico subsidiary, welcoming Grupo Carso as a co-owner in a structure that establishes a baseline valuation for Zama but retains significant upside as we work to maximize the value of that asset. Finally, we are pleased to see the progress in our CCS business. We recently filed a Class VI permit application, which is an important milestone. We also continue to explore a capital raise for our Talos Low Carbon Solution platform and we'll provide an update when appropriate."

RECENT DEVELOPMENTS AND OPERATIONS UPDATE

Shareholder Return Program: During the second quarter 2023, Talos opportunistically repurchased 1.5 million shares of common stock for $20.9 million, representing an average price of $13.89 per share. As of June 30, 2023, the Company has purchased 3.4 million shares or 3% of total outstanding shares with remaining authorization to repurchase up to approximately $52.5 million of additional common stock under its $100 million program.

Mexico Divestiture: In May 2023, Talos announced a transaction with Grupo Carso to sell a 49.9% interest in Talos Mexico, which holds a 17.4% stake in Zama. The transaction valued the Talos Mexico entity at a $250 million valuation. Talos expects to receive approximately $125 million for the 49.9% stake, including approximately $75 million paid at closing and approximately $50 million due upon first production. The transaction is expected to close during the third quarter 2023, subject to regulatory approval.

In June 2023, Mexico's Comisión Nacional de Hidrocarburos approved the Zama Unit Development Plan previously submitted in March 2023. Talos is actively working with the Zama Unit's Integrated Project Team to progress the front-end engineering and design ("FEED") and other workstreams required to reach a Final Investment Decision ("FID").

Drilling and Completion Updates:

Lime Rock and Venice: Completion, construction, and subsea installation operations for Talos's Lime Rock and Venice discoveries remain on track. The Company anticipates first production by the first quarter 2024 from both wells, which will be tied-backed to the Talos owned and operated Ram Powell facility. Talos owns a 60% working interest in both wells.

Sunspear: The Sunspear exploitation well successfully discovered commercial quantities of oil and natural gas in July 2023. Talos's preliminary post-drill analysis indicates approximately 260 feet of gross true vertical thickness of oil pay (177 feet net across two targets), including 149 feet of net oil pay in the main target in line with pre-drill expectations. The project will flow to the recently acquired Prince platform with first oil expected in the next 18 to 24 months. Working interest partners are Talos 48.0%, an entity managed by Ridgewood Energy Corporation 47.5%, and Houston Energy 4.5%.

Longhorn: The Longhorn prospect, designed to test deep objectives underneath the Lobster field, found non-commercial levels of hydrocarbons in the deep zone, though the well encountered over 50 feet of pay across two legacy field pays. The well has been suspended and will be analyzed for completion alongside the next Lobster field development well, which is expected to spud in the third quarter 2023.

Pancheron: Drilling of the Pancheron exploration prospect in the second quarter 2023 encountered non-commercial quantities of hydrocarbons, and plugging and abandonment operations have been completed. Talos held a 30% working interest, bp held a 33% working interest, and Oxy held a 37% working interest and was the operator. Pre-drill probability of success was estimated at approximately 30%.

Other Operated Production and Downtime Updates: During the second quarter 2023, Talos completed the planned well interventions on its operated Bulleit DTR-10 Sand recompletion and Mount Hunter development well. The interventions successfully improved overall reservoir productivity. Additionally, on Talos's operated Neptune facility, the Company continues to work on optimization efforts, including new chemical treatments and topside modifications, expected to be completed in the fourth quarter 2023.

Non-Operated Project Updates: The Odd Job subsea pump project, operated by Kosmos Energy, which is intended to sustain long-term production from the field, continues to progress and remains on track to be in service by mid-2024. Talos has a 17.5% working interest. Drilling on the Marmalard well, operated by Murphy Oil, is expected to commence in the third quarter 2023. Talos holds a 11.4% working interest.

TLCS Updates:

Exploring Capital Raise: Talos continues to explore a capital raise to scale up the development of its existing TLCS portfolio and accelerate its growth. The Company will provide further updates when available.

Stratigraphic Wells and Class VI Permits: As previously announced, the Bayou Bend partnership has contracted a rig and expects to drill a Talos-operated offshore stratigraphic well during the second half 2023. Additionally, the partnership expects to drill a Chevron-operated onshore stratigraphic well in the first half 2024. Separately, in early August 2023, TLCS filed its first EPA Class VI permit for its Harvest Bend CCS project (formerly known as River Bend CCS), in which TLCS holds a 60% interest. TLCS also intends to file at least one additional EPA Class VI permit application across its portfolio by year-end.

SECOND QUARTER 2023 RESULTS

Key Financial Highlights:

($ thousands, except per share and per BOE amounts)		Three Months Ended June 30, 2023
Total revenues	$	367,210
Net income	$	13,677
Net income per diluted share	$	0.11
Adjusted Net Income[1]	$	11,537
Adjusted Net Income per diluted share[1]	$	0.09
Adjusted EBITDA[1]	$	249,723
Adjusted EBITDA excluding hedges[1]	$	241,561
Upstream Adjusted EBITDA[1]	$	253,615
Upstream Adjusted EBITDA excluding hedges[1]	$	245,453
Capital Expenditures (including Plug & Abandonment, Decommissioning Obligations Settled and CCS)	$	191,205
Upstream Adjusted EBITDA Margin:		
Upstream Adjusted EBITDA per Boe[1]	$	39.67
Upstream Adjusted EBITDA excluding hedges per Boe[1]	$	38.39

Production

Production was 70.3 MBoe/d for the second quarter 2023 and was 75% oil and 83% liquids.

	Three Months Ended June 30, 2023
Average daily production volumes	
Oil (MBbl/d)	52.8
Natural Gas (MMcf/d)	72.9
NGL (MBbl/d)	5.3
Total average daily (MBoe/d)	70.3

	Three Months Ended June 30, 2023			
	Production	% Oil	% Liquids	% Operated
Average daily production volumes by Core Area (MBoe/d)				
Green Canyon Area	22.7	84%	91%	88%
Mississippi Canyon Area	34.6	79%	87%	70%
Shelf and Gulf Coast	13.0	50%	58%	61%
Total average daily (MBoe/d)	70.3	75%	83%	74%

Lease Operating & General and Administrative Expenses

Total lease operating expenses, inclusive of workover and maintenance and insurance costs for the quarter, were $101.2 million or $15.82/Boe. Upstream General and Administrative expenses for the quarter, excluding non-cash equity-based compensation, was $25.0 million, or $3.91/Boe. Upstream General and Administrative expenses is shown inclusive of $3.5 million in transaction-related expenses.

($ thousands, except per BOE amounts)	Three Months Ended June 30, 2023	Per Boe
Lease Operating Expenses	$ 101,165	$ 15.82
Upstream General & Administrative Expenses (excluding non-cash equity-based compensation)[1]	$ 24,994	$ 3.91

Capital Expenditures

Upstream capital expenditures, including plugging and abandonment, totaled $189.3 million for the second quarter 2023.

($ thousands)	Three Months Ended June 30, 2023	Six Months Ended June 30, 2023
Upstream Capital Expenditures		
U.S. drilling & completions	$ 120,331	$ 232,661
Mexico appraisal & exploration	101	197
Asset management[1]	15,784	60,728
Seismic and G&G, land, capitalized G&A and other	14,212	36,045
Total Upstream Capital Expenditures	150,428	329,631
Plugging & Abandonment	37,570	47,683
Decommissioning Obligations Settled[2]	1,339	2,047
Total Upstream	$ 189,337	$ 379,361

(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 $2.4 million for the second quarter 2023, which is accounted for in the Company's reported Adjusted EBITDA figure. CCS capital expenditures totaled $1.9 million for the second quarter 2023, which mainly includes investments in Bayou Bend and funding for general ongoing operations.

($ thousands)	Three Months Ended June 30, 2023	Six Months Ended June 30, 2023
CCS Investments		
CCS Expenses	$ 2,360	$ 8,517
CCS Capital Expenditures	1,868	23,057
Total CCS Investments	$ 4,228	$ 31,574

Liquidity and Leverage

At June 30, 2023, Talos had approximately $771.8 million of liquidity, with $765.0 million undrawn on its credit facility and approximately $17.5 million in cash, less approximately $10.8 million in outstanding letters of credit.

On June 30, 2023, Talos had $1,081.0 million in total debt. Net Debt was $1,063.5 million[1]. Net Debt to Pro Forma LTM Adjusted EBITDA was 1.0x[1].

Footnotes:

(1) Adjusted Net Income (Loss), Adjusted Income (Loss) per Share, Adjusted EBITDA, Adjusted EBITDA excluding hedges, Upstream Adjusted EBITDA, Upstream Adjusted EBITDA excluding hedges, Adjusted EBITDA margin, Adjusted EBITDA margin excluding hedges, Upstream Adjusted EBITDA margin or per Boe, Upstream Adjusted EBITDA margin excluding hedges or per Boe, Upstream General and Administrative Expenses, Credit Facility LTM Adjusted EBITDA, Net Debt, Net Debt to Pro Forma 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 August 8, 2023:

	Instrument Type	Avg. Daily Volume	W.A. Swap	W.A. Sub-Floor	W.A. Floor	W.A. Ceiling
Crude – WTI		*(Bbls)*	*(Per Bbl)*	*(Per Bbl)*	*(Per Bbl)*	*(Per Bbl)*
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	18,500	$ 72.68	---	---	---
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)*
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	25,000	$ 3.33	---	---	---
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 Wednesday, August 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 August 16, 2023 and can be accessed by dialing (877) 344-7529 and using access code 7754475.

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

The information in this communication includes “forward-looking statements” within the meaning of the Securities Act of 1933, as amended (the “Securities Act”), and the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical fact included in this communication 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. Forward-looking statements are based on management’s current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. Forward-looking statements may include statements about: business strategy; reserves; drilling prospects, inventories, projects and programs; our ability to replace the reserves through drilling and property acquisitions; financial strategy, liquidity and capital required for our development program and other capital expenditures; realized oil and natural gas prices; timing and amount of future production of oil, natural gas and NGLs; our hedging strategy and results; future drilling and CCS plans; availability of pipeline connections on economic terms; competition, government regulations and legislative and political developments; our ability to obtain permits and governmental approvals; pending legal, governmental or environmental matters; our marketing of our products; our integration of acquisitions, including EnVen, and future performance of the combined company; future leasehold or business acquisitions on desired terms; costs of developing properties; general economic conditions, including the impact of continued inflation and associated changes in monetary policy; political and economic conditions and events in foreign oil, natural gas and NGL producing countries, including embargoes, hostilities and acts of terrorism or sabotage; credit markets; estimates of future income taxes; our estimates and forecasts of the timing, number, profitability and other results of wells we expect to drill and other exploration activities; the success of our CCS opportunities, including as a result of the associated permitting process, our access to capital to finance such opportunities, the timing and amount of revenues therefrom and potential future customers; the uncertainty inherent in estimating subsurface storage resources and utilization capacity in our CCS projects; our ongoing strategy with respect to our Zama asset; uncertainty regarding our future operating results and our future revenues and expenses; impact of new accounting pronouncements on earnings in future periods; and plans, objectives, expectations and intentions contained in this communication that are not historical.

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. Examples of such risks include, but are not limited to, commodity price volatility; global demand for oil and natural gas; the ability or willingness of OPEC and other state-controlled oil companies (“OPEC Plus”) to set and maintain oil production levels; the impact of any such actions; the lack of a resolution to the war in Ukraine and its impact on certain commodity markets; lack of transportation and storage capacity as a result of oversupply, government and regulations; lack of availability of drilling and production equipment and services; adverse weather events, including tropical storms, hurricanes and winter storms; cybersecurity threats; sustained inflation and the impact of governmental policy in response thereto; 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; risks associated with permitting for—and access to capital to finance—our CCS opportunities; and the other risks discussed in Part I, Item 1A. “Risk Factors” of Talos Energy Inc.’s Annual Report on Form 10-K for the year ended December 31, 2022 (the “2022 Annual Report”) and Part II, Item IA. “Risk Factors” of Talos Energy Inc.’s Quarterly Report on Form 10-Q for the period ended March 31, 2023, each as filed with the SEC.

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 upward or downward revisions 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 terms “gross true vertical thickness,” “TVT” and “oil pay” in this communication, which are not measures 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.

Should any risks or uncertainties 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.

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

	June 30, 2023 (Unaudited)	December 31, 2022
ASSETS		
Current assets:		
Cash and cash equivalents	$ 17,525	$ 44,145
Accounts receivable:		
Trade, net	157,329	150,598
Joint interest, net	86,615	54,697
Other, net	30,233	6,684
Assets from price risk management activities	45,522	25,029
Prepaid assets	85,697	84,759
Other current assets	17,251	1,917
Total current assets	440,172	367,829
Property and equipment:		
Proved properties	7,526,625	5,964,340
Unproved properties, not subject to amortization	401,710	154,783
Other property and equipment	32,088	30,691
Total property and equipment	7,960,423	6,149,814
Accumulated depreciation, depletion and amortization	(3,822,916)	(3,506,539)
Total property and equipment, net	4,137,507	2,643,275
Other long-term assets:		
Restricted cash	100,973	—
Assets from price risk management activities	8,655	7,854
Equity method investments	22,436	1,745
Other well equipment inventory	44,645	25,541
Notes receivable, net	15,413	—
Operating lease assets	18,104	5,903
Other assets	17,508	6,479
Total assets	$ 4,805,413	$ 3,058,626
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 184,177	$ 128,174
Accrued liabilities	220,417	219,769
Accrued royalties	51,248	52,215
Current portion of long-term debt	33,156	—
Current portion of asset retirement obligations	57,551	39,888
Liabilities from price risk management activities	8,247	68,370
Accrued interest payable	42,351	36,340
Current portion of operating lease liabilities	3,136	1,943
Other current liabilities	91,599	60,359
Total current liabilities	691,882	607,058
Long-term liabilities:		
Long-term debt	1,000,109	585,340
Asset retirement obligations	741,501	501,773
Liabilities from price risk management activities	1,417	7,872
Operating lease liabilities	25,173	14,855
Other long-term liabilities	283,443	176,152
Total liabilities	2,743,525	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 June 30, 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 June 30, 2023 and December 31, 2022, respectively	1,275	826
Additional paid-in capital	2,539,629	1,699,799
Accumulated deficit	(431,512)	(535,049)
Treasury stock, at cost; 3,400,000 and zero shares as of June 30, 2023 and December 31, 2022, respectively	(47,504)	—
Total stockholders' equity	2,061,888	1,165,576
Total liabilities and stockholders' equity	$ 4,805,413	$ 3,058,626

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Revenues:				
Oil	$ 342,983	$ 429,329	$ 635,677	$ 783,215
Natural gas	16,329	70,406	36,512	113,387
NGL	7,898	19,350	17,603	36,049
Total revenues	367,210	519,085	689,792	932,651
Operating expenses:				
Lease operating expense	101,165	87,582	182,527	147,396
Production taxes	607	864	1,213	1,715
Depreciation, depletion and amortization	169,794	104,511	317,117	202,851
Accretion expense	22,760	14,844	42,174	29,221
General and administrative expense	33,182	22,925	96,369	45,453
Other operating (income) expense	(723)	12,372	2,115	12,508
Total operating expenses	326,785	243,098	641,515	439,144
Operating income	40,425	275,987	48,277	493,507
Interest expense	(45,632)	(30,776)	(83,213)	(62,266)
Price risk management activities income (expense)	26,197	(64,094)	85,134	(345,313)
Equity method investment income (expense)	(2,012)	13,466	5,431	13,608
Other income	1,591	3,165	8,257	31,299
Net income before income taxes	20,569	197,748	63,886	130,835
Income tax benefit (expense)	(6,892)	(2,607)	39,651	(2,135)
Net income	$ 13,677	$ 195,141	$ 103,537	$ 128,700
Net income per common share:				
Basic	$ 0.11	$ 2.36	$ 0.90	$ 1.56
Diluted	$ 0.11	$ 2.33	$ 0.89	$ 1.55
Weighted average common shares outstanding:				
Basic	125,436	82,566	115,590	82,320
Diluted	125,667	83,665	116,363	83,247

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

	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
Cash flows from operating activities:		
Net income	$ 103,537	$ 128,700
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion expense	359,291	232,072
Amortization of deferred financing costs and original issue discount	7,629	6,952
Equity-based compensation expense	8,687	7,367
Price risk management activities expense (income)	(85,134)	345,313
Net cash paid on settled derivative instruments	(4,161)	(287,321)
Equity method investment income	(5,431)	(13,608)
Settlement of asset retirement obligations	(47,683)	(39,768)
Loss on sale of assets	—	390
Changes in operating assets and liabilities:		
Accounts receivable	35,127	(57,394)
Other current assets	(23,790)	(31,435)
Accounts payable	(3,890)	23,360
Other current liabilities	(22,975)	33,284
Other non-current assets and liabilities, net	(44,124)	6,453
Net cash provided by operating activities	277,083	354,365
Cash flows from investing activities:		
Exploration, development and other capital expenditures	(298,658)	(128,082)
Proceeds from (cash paid for) acquisitions, net of cash acquired	17,617	(3,500)
Proceeds from (cash paid for) sale of property and equipment, net	(8,488)	1,597
Contributions to equity method investees	(15,260)	(2,250)
Proceeds from sale of equity method investments	—	15,000
Investment in intangible assets	(7,796)	—
Net cash used in investing activities	(312,585)	(117,235)
Cash flows from financing activities:		
Redemption of senior notes	(15,000)	(6,060)
Proceeds from Bank Credit Facility	505,000	35,000
Repayment of Bank Credit Facility	(305,000)	(210,000)
Deferred financing costs	(11,775)	(129)
Other deferred payments	(462)	—
Payments of finance lease	(8,026)	(12,836)
Purchase of treasury stock	(47,504)	—
Employee stock awards tax withholdings	(7,378)	(4,476)
Net cash provided by (used in) financing activities	109,855	(198,501)
Net increase in cash, cash equivalents and restricted cash	74,353	38,629
Cash, cash equivalents and restricted cash:		
Balance, beginning of period	44,145	69,852
Balance, end of period	$ 118,498	$ 108,481
Supplemental non-cash transactions:		
Capital expenditures included in accounts payable and accrued liabilities	$ 113,319	$ 47,354
Supplemental cash flow information:		
Interest paid, net of amounts capitalized	$ 63,492	$ 47,570

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 "Upstream General and Administrative Expenses," "Adjusted Net Income (Loss)," "Adjusted Earnings per Share," "EBITDA," "Adjusted EBITDA," "Upstream Adjusted EBITDA," "Adjusted EBITDA excluding hedges," "Upstream Adjusted EBITDA excluding hedges," "Adjusted EBITDA Margin," "Upstream Adjusted EBITDA Margin," "Adjusted EBITDA Margin excluding hedges," "Upstream Adjusted EBITDA Margin excluding hedges," "Adjusted Free Cash Flow," "Net Debt," "LTM Adjusted EBITDA," "Credit Facility LTM Adjusted EBITDA,", "Net Debt to Pro Forma 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 General and Administrative Expenses to Upstream General and Administrative Expenses

We believe the presentation of Upstream General and Administrative Expenses excluding non-cash equity-based compensation 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. Upstream General & Administrative Expenses 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:

General and Administrative Expenses. Generally consists of costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production operations, bad debt expense, equity-based compensation expense, audit and other fees for professional services and legal compliance. A portion of these expenses are allocated based on the percentage of employees dedicated to each operating segment.

($ thousands)	**Three Months Ended June 30, 2023**
Reconciliation of General & Administrative Expenses to Upstream General & Administrative Expenses (excluding non-cash equity-based compensation):	
Total General and Administrative Expenses	$ 33,182
CCS Segment	(2,445)
Unallocated corporate	(1,836)
Non-cash equity-based compensation expense	(3,907)
Upstream General & Administrative Expenses (excluding non-cash equity-based compensation)	$ 24,994

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

"EBITDA," "Adjusted EBITDA" and "Upstream 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.

Upstream Adjusted EBITDA. Adjusted EBITDA plus certain CCS and corporate unallocated costs of equity method investment loss, general and administrative expense, other operating income, other income, and non-cash equity-based compensation expense.

We also present Adjusted EBITDA excluding hedges and Upstream Adjusted EBITDA excluding hedges as a percentage of revenue and on a per barrel of oil equivalent basis, respectively, to further analyze our business, which are outlined below:

Adjusted EBITDA Margin and Upstream Adjusted EBITDA Margin. Adjusted EBITDA divided by Revenue, as a percentage. It is also defined as Upstream 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 of Upstream Adjusted EBITDA we generate after accounting for certain operational and corporate costs.

The following tables present a reconciliation of the GAAP financial measure of Net Income (loss) to EBITDA, Adjusted EBITDA, Upstream Adjusted EBITDA, Adjusted EBITDA excluding hedges, Upstream Adjusted EBITDA excluding hedges, Upstream Adjusted EBITDA Margin and Upstream Adjusted EBITDA Margin excluding hedges for each of the periods indicated (in thousands, except for Boe, $/Boe and percentage data):

	Three Months Ended			
($ thousands)	**June 30, 2023**	**March 31, 2023**	**December 31, 2022**	**September 30, 2022**
Reconciliation of Net Income (Loss) to Adjusted EBITDA:				
Net Income	$ 13,677	$ 89,860	$ 2,750	$ 250,465
Interest expense	45,632	37,581	33,967	29,265
Income tax expense (benefit)	6,892	(46,543)	281	121
Depreciation, depletion and amortization	169,794	147,323	119,456	92,323
Accretion expense	22,760	19,414	13,595	13,179
EBITDA	258,755	247,635	170,049	385,353
Transaction and other (income) expenses[1]	3,513	22,009	4,343	3,219
Decommissioning obligations[2]	741	741	21,005	20
Derivative fair value (gain) loss[3]	(26,197)	(58,937)	41,058	(114,180)
Net cash received (paid) on settled derivative instruments[3]	8,162	(12,323)	(57,076)	(81,162)
Loss on extinguishment of debt	—	—	1,569	—
Non-cash equity-based compensation expense	4,749	3,938	4,276	4,310
Adjusted EBITDA	249,723	203,063	185,224	197,560
Add: Net cash (received) paid on settled derivative instruments[3]	(8,162)	12,323	57,076	81,162
Adjusted EBITDA excluding hedges	$ 241,561	$ 215,386	$ 242,300	$ 278,722
Revenue:				
Revenue - Operations	367,210	322,582	342,201	377,128
Adjusted EBITDA margin and Adjusted EBITDA excl hedges margin:				
Adjusted EBITDA divided by - Total revenue incl hedges (%)	67%	65%	65%	67%
Adjusted EBITDA divided by - Total revenue (%)	66%	67%	71%	74%

(1) For the three months ended June 30, 2023, transaction expenses include $2.7 million in costs related to the EnVen Acquisition, inclusive of $1.4 million in severance expense. 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. Transaction expenses are included in "General and administrative expense" on our consolidated statements of operations. 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 that is included in "Equity method investment income (expense)" on our consolidated statements of operations.

(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 and are included in "Other operating (income) expense" on our consolidated statements of operations.

(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.

($ thousands, except per BOE amounts)	Three Months Ended June 30, 2023
Reconciliation of Adjusted EBITDA to Upstream Adjusted EBITDA:	
Adjusted EBITDA	$ 249,723
CCS and Corporate Unallocated Costs:	
Equity method investment loss	2,135
General and administrative expense	4,279
Other operating income	(1,654)
Other income	(26)
Non-cash equity-based compensation expense	(842)
Upstream Adjusted EBITDA	253,615
Add: Net cash received on settled derivative instruments[1]	(8,162)
Upstream Adjusted EBITDA excluding hedges	$ 245,453
Production:	
Boe[2]	6,393
Upstream Adjusted EBITDA margin and Upstream Adjusted EBITDA excl hedges margin:	
Upstream Adjusted EBITDA per Boe[2]	$ 39.67
Upstream Adjusted EBITDA excl hedges per Boe[1][2]	$ 38.39

(1) 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.

(2) 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.

($ thousands)	Three Months Ended June 30, 2023
Reconciliation of Adjusted EBITDA to Adjusted Free Cash Flow (before changes in working capital)	
Adjusted EBITDA	$ 249,723
Upstream capital expenditures	(150,428)
Plugging & abandonment	(37,570)
Decommissioning obligations settled	(1,339)
CCS capital expenditures	(1,868)
Interest expense	(45,632)
Adjusted Free Cash Flow (before changes in working capital)	$ 12,886

($ thousands)	Three Months Ended June 30, 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)	$ 214,226
(Increase) decrease in operating assets and liabilities	(53,358)
Upstream capital expenditures(2)	(150,428)
Decommissioning obligations settled	(1,339)
CCS capital expenditures	(1,868)
Transaction and other (income) expenses(3)	3,513
Decommissioning obligations(4)	741
Amortization of deferred financing costs and original issue discount	(3,481)
Income tax benefit	6,892
Other adjustments	(2,012)
Adjusted Free Cash Flow (before changes in working capital)	$ 12,886

(1) Includes settlement of asset retirement obligations.
(2) Includes accruals and excludes acquisitions.
(3) For the three months ended June 30, 2023, transaction expenses include $2.7 million in costs related to the EnVen Acquisition, inclusive of $1.4 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.

	Three Months Ended June 30, 2023		
($ thousands, except per share amounts)		Basic per Share	Diluted per Share
Reconciliation of Net Income to Adjusted Net Loss:			
Net Income	$ 13,677	$ 0.11	$ 0.11
Transaction and other (income) expenses(1)	3,513	$ 0.03	$ 0.03
Decommissioning obligations(2)	741	$ 0.01	$ 0.01
Derivative fair value gain(3)	(26,197)	$ (0.21)	$ (0.21)
Net cash received on settled derivative instruments(3)	8,162	$ 0.07	$ 0.06
Non-cash income tax expense	6,892	$ 0.05	$ 0.05
Non-cash equity-based compensation expense	4,749	$ 0.04	$ 0.04
Adjusted Net Income	$ 11,537	$ 0.09	$ 0.09
Weighted average common shares outstanding at June 30, 2023:			
Basic	125,436		
Diluted	125,667		

(1) For the three months ended June 30, 2023, transaction expenses include $2.7 million in costs related to the EnVen Acquisition, inclusive of $1.4 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.

(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 minus cash and cash equivalents.

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

($ thousands)		June 30, 2023
Reconciliation of Net Debt:		
12.00% Second-Priority Senior Secured Notes – due January 2026	$	638,541
11.75% Senior Secured Second Lien Notes – due April 2026		242,500
Bank Credit Facility – matures March 2027		200,000
Total Debt		1,081,041
Less: Cash and cash equivalents		(17,525)
Net Debt	$	1,063,516
Calculation of LTM Adjusted EBITDA:		
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
Adjusted EBITDA for three months period ended June 30, 2023		249,723
LTM Adjusted EBITDA	$	835,570
Acquired Assets Adjusted EBITDA:		
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 the period January 1, 2023 to February 13, 2023		33,120
LTM Adjusted EBITDA from Acquired Assets	$	209,878
Pro Forma LTM Adjusted EBITDA	$	1,045,448
Reconciliation of Net Debt to Pro Forma LTM Adjusted EBITDA:		
Net Debt / Pro Forma LTM Adjusted EBITDA(1)		1.0x

(1) Net Debt / Pro Forma LTM Adjusted EBITDA figure excludes the Finance Lease. Had the Finance Lease been included, Net Debt / Pro Forma LTM Adjusted EBITDA would have been 1.2x.