SU-TO gideon lens

■# Suncor Energy Inc. (SU.TO) - Gideon Lens

Report ID: SU-TO-GIDEON-20260906T220342+0800 **Report date:** 2026-09-06 **Price anchor:** C$93.14 per XTSE:SU common share at the 2026-09-04 close **Forecast anchor and horizon:** TTM ended 2026-06-30 to 2031-06-30, exactly 5.0 years **Mode:** Production ER2

Investment conclusion

Suncor is a financially sound, increasingly well-run integrated energy company, but it is not a durable high-ROIIC compounder and the current share price offers poor security-level returns. Long-life Oil Sands resources, upgrading, logistics, refining and retail integration help Suncor survive dislocations that can hurt narrower peers. They do not create pricing power over oil benchmarks, differentials or crack spreads. That distinction is decisive. The Moat and 2046 tests both fail, Management is YELLOW because the April 2027 CEO transition and permanent CFO solution are not yet proven, and the audited score is only 45/100.

The P/E-at-15 entry test passes mechanically: Base 2031 EPS of C$7.826694 is 26.05% above the C$6.209333 required at today's price. That gate does not mean the stock is cheap. The independently locked through-cycle P/E method assigns 12x to depressed Bear EPS, 10x to Base EPS and 7x to peak-like Bull EPS. Adding modeled distributions produces gross CAD IRRs of -17.52%, -0.15% and 4.11%. Probability-weighted terminal wealth is only C$80.817075 per share, below the C$93.14 starting price, for a -2.80% annual return. The net-SGD diagnostic is weaker. Suncor therefore earns an ER2 verdict of PASS and a separate CIO actionability status of PASS, with no proposed sizing.

What the business evidence says

Suncor's FY2025 revenue mix is led by Refining and Marketing, but Oil Sands supplies the largest profit pool. The TTM statutory bridge is clean: C$60.729B revenue, C$13.665B operating income, C$12.029B pretax income and C$8.927B net income. Oil Sands contributed C$20.888B of TTM revenue and C$6.965B of pretax segment profit; E&P contributed C$3.223B and C$1.050B; R&M contributed C$36.617B and C$5.523B. Corporate and Eliminations reduced pretax profit by C$1.509B. Every segment forecast was separately reviewed and the consolidated synthesis passed all 11 tie-outs.

The Base case is deliberately not a heroic revenue story. Revenue reaches C$63.812B, a five-year CAGR of only 1.00%. Oil Sands rises to C$23.671B of revenue and C$7.034B of pretax profit as brownfield volume, reliability and cost programs offset normalization from a strong TTM period. E&P reaches C$3.587B and C$1.040B as West White Rose and development drilling offset decline. R&M revenue is almost flat at C$36.553B while pretax profit normalizes to C$3.730B. Consolidated operating income is C$12.054B and net income is C$7.947720B.

Per-share growth relies heavily on capital allocation. The Base model retires 193.365M shares through C$22.0B of repurchases while issuing 29.829M shares for modeled stock compensation, ending at 1,015.463M diluted listed-equivalent shares. That is a net reduction of 163.537M shares, or 13.9% of the opening 1,179.0M. This is possible given recent free-cash generation and management's repurchase cadence, but it is not self-proving. Red team correctly identifies C$22.0B of Base repurchases as the most optimistic synthesis number because assumed repurchase prices rise even though the audited Base terminal share value is only C$78.27.

Management has improved safety, reliability, balance-sheet discipline and capital returns under Rich Kruger. The evidence does not yet justify a PASS gate because Peter Zebedee's planned move into the CEO role in April 2027 is untested at that level and the permanent CFO succession remains unresolved. The management appendix therefore holds YELLOW. The moat conclusion is firmer: physical scarcity and integration improve resilience, but high returns still depend on commodity realizations, differentials, utilization and location. Suncor lacks demonstrated cycle-independent pricing power, and reserve replacement, road-fuel demand and carbon/reclamation liabilities weaken the 2046 case.

Verdict: PASS

Scorecard:

Gate	Result	Notes
Management	YELLOW	Strong reset; CEO and permanent-CFO succession remain unproven

Gate	Result	Notes
Moat	FAIL	Physical resilience lacks pricing power; 2046 test fails
P/E <= 15 on confident EPS at TTM + 5 calendar years	PASS	Base EPS gives a 26.0473% cushion
Compounder Score	Audited 45 / 100	Reject classification; diagnostic confirms poor risk-adjusted economics
Business Quality Score	Audited 43 / 80	Below dream-business threshold; ROIIC and durability are unproven
20% Return UW Score	Audited 2 / 20	All locked scenarios miss 20%; required multiple expansion is major

One-line thesis (or reason to pass): Suncor's integrated assets and recent operating discipline are real, but a failed long-duration moat and probability-weighted wealth below today's price make the common shares unattractive at C$93.14.

Security return underwriting (mandatory even when the verdict is PASS):

Measure	Result	Notes
Primary valuation method	P/E	One audited method used for every scenario, probability weighting, reverse return and net-SGD
Gross local-currency bear / base / bull IRR	-17.52% / -0.15% / 4.11%	Five-year annualized shareholder return in CAD
Probability-weighted gross local-currency IRR	-2.80%	CAGR of C$80.817075 expected terminal wealth; weights 28% / 52% / 20%
Return bridge	C$93.14 -> C$35.555550 / C$92.455498 / C$113.923312	Terminal EPS times 12x / 10x / 7x P/E plus distributions; no second cash/debt adjustment

Gross local-currency underwriting is in CAD; net-SGD adjustments appear separately in CIO actionability. Operating figures begin at the 2026-06-30 TTM anchor; price and market valuation begin at the 2026-09-04 close. Values are CAD billions except per-share amounts and diluted shares in millions.

Bear-case operating and return bridge

Bear case	Start (2026-09-04; TTM 2026-06-30)	Horizon (2031-06-30)	CAGR / change	Justification
Revenue	C$60.729B	C$49.657B	-3.95%	Weaker realizations, E&P setbacks and softer refining conditions
Operating margin	22.50%	9.89%	-12.61 pp	Oil Sands cost/volume stress and higher corporate burden
Operating earnings	C$13.665B	C$4.910B	-18.51%	Statutory operating income from the reviewed segment bridge
Diluted share count	1,179.000M	1,157.592M	-0.37%	C$5.0B repurchases are mostly offset by modeled SBC issuance
EPS	C$7.4672	C$2.0418	-22.84%	Statutory diluted EPS after financing, tax and share count
Valuation denominator	TTM EPS C$7.4672; normalized FY2025 EPS C$4.8548	2031 EPS C$2.0418	Comparable after normalization	Event-heavy TTM is disclosed; FY2025 provides through-cycle context
Valuation	12.47x reported / 19.19x normalized P/E	12.00x P/E	-0.47x vs reported	Trough-like positive EPS receives a higher cycle multiple, within history
Share value	C$93.14	C$24.5019	-23.44%	C$2.041825 EPS times 12.0x; no net-cash adjustment
Annual dividend	C$2.4054 annualized	C$2.0749	-2.91%	H1 2026 annualized start; modeled 2031 C$2.4B payout per average shares
Dividend yield	2.58%	8.47%	+5.89 pp	Dividend per share divided by endpoint share value
Five-year dividends	-	C$11.053650	cumulative	Modeled cash distributions counted once

Bear case	Start (2026-09-04; TTM 2026-06-30)	Horizon (2031-06-30)	CAGR / change	Justification
Total ending value	C$93.14	C$35.555550	-17.52% gross CAD IRR	C$24.501900 share value plus C$11.053650 distributions

Base-case operating and return bridge

Base case	Start (2026-09-04; TTM 2026-06-30)	Horizon (2031-06-30)	CAGR / change	Justification
Revenue	C$60.729B	C$63.812B	1.00%	Brownfield upstream growth offsets normalized refining and fuel pressure
Operating margin	22.50%	18.89%	-3.61 pp	Through-cycle margins remain below the strong TTM anchor
Operating earnings	C$13.665B	C$12.054B	-2.48%	Statutory operating income from segment profit and explicit corporate bridge
Diluted share count	1,179.000M	1,015.463M	-2.94%	C$22.0B repurchases net of modeled SBC issuance
EPS	C$7.4672	C$7.8267	0.94%	Share shrinkage offsets lower operating income
Valuation denominator	TTM EPS C$7.4672; normalized FY2025 EPS C$4.8548	2031 EPS C$7.8267	Comparable after normalization	Same statutory diluted common-share perimeter
Valuation	12.47x reported / 19.19x normalized P/E	10.00x P/E	-2.47x vs reported	Interior through-cycle anchor; no use of the 15x entry gate
Share value	C$93.14	C$78.2669	-3.42%	C$7.826694 EPS times 10.0x; no net-cash adjustment
Annual dividend	C$2.4054 annualized	C$3.1993	5.87%	Modeled 2031 C$3.3B payout per average shares
Dividend yield	2.58%	4.09%	+1.50 pp	Dividend per share divided by endpoint share value
Five-year dividends	-	C$14.188558	cumulative	Modeled cash distributions counted once
Total ending value	C$93.14	C$92.455498	-0.15% gross CAD IRR	C$78.266940 share value plus C$14.188558 distributions

Bull-case operating and return bridge

Bull case	Start (2026-09-04; TTM 2026-06-30)	Horizon (2031-06-30)	CAGR / change	Justification
Revenue	C$60.729B	C$75.350B	4.41%	Strong realizations, reliability, projects and downstream capture coincide
Operating margin	22.50%	26.50%	+4.00 pp	Favorable commodity and refining conditions with cost absorption
Operating earnings	C$13.665B	C$19.967B	7.88%	Statutory operating income from reviewed segment profits
Diluted share count	1,179.000M	982.986M	-3.57%	C$30.0B repurchases net of modeled SBC issuance
EPS	C$7.4672	C$14.0113	13.41%	Strong earnings and the largest share reduction act together
Valuation denominator	TTM EPS C$7.4672; normalized FY2025 EPS C$4.8548	2031 EPS C$14.0113	Comparable after normalization	Terminal EPS is peak-like and receives compression
Valuation	12.47x reported / 19.19x normalized P/E	7.00x P/E	-5.47x vs reported	Anchored near Suncor's 6.58x-6.71x peak-earnings history
Share value	C$93.14	C$98.0790	1.04%	C$14.011292 EPS times 7.0x; no net-cash adjustment

Bull case	Start (2026-09-04; TTM 2026-06-30)	Horizon (2031-06-30)	CAGR / change	Justification
Annual dividend	C$2.4054 annualized	C$3.7917	9.53%	Modeled 2031 C$3.8B payout per average shares
Dividend yield	2.58%	3.87%	+1.28 pp	Dividend per share divided by endpoint share value
Five-year dividends	-	C$15.844268	cumulative	Modeled cash distributions counted once
Total ending value	C$93.14	C$113.923312	4.11% gross CAD IRR	C$98.079044 share value plus C$15.844268 distributions

CIO actionability (separate from ER2 underwriting):

Measure	Result	Notes
Status	PASS	Hard Moat/2046 failure and negative central returns preclude allocation
Bear / Base / Bull net SGD IRR	-19.76% / -0.69% / 5.23%	Five-year annualized after 20 bp entry/exit costs, 15% dividend withholding and scenario FX
Probability-weighted net SGD IRR	-3.12%	CAGR of weighted terminal SGD wealth; weights 28% / 52% / 20%
10% mandate hurdle	FAIL	Base and probability-weighted cases are both below 10%
15% stretch hurdle	FAIL	No audited scenario reaches 15% net SGD
Downside and portfolio fit	UNAVAILABLE	Security downside fails; portfolio holdings and risk budget were not provided
Proposed sizing ceiling	none	Research proposes no allocation; any future action requires owner approval

The net-SGD diagnostic starts at 0.9154155987 SGD per CAD from the Bank of Canada 2026-09-04 rate. Terminal FX stresses are 0.84 Bear, 0.9154155987 Base and 0.99 Bull. It applies 0.20% entry and exit costs and 15% Canadian withholding on distributions under the Canada-Singapore treaty. Investor-specific residency, wrapper, broker and tax facts remain unavailable, so this is a conservative diagnostic, not personal tax advice.

Trade execution authorized: NO

What could change the conclusion

The audited Base maximum price for a 20% five-year return is C$37.155791. That is not an automatic BUY trigger because the Moat gate still fails; it is only a return-based reconsideration level. A genuine upgrade would also require evidence of cycle-independent value creation: measurable acquisition-inclusive ROIIC above cost of capital, durable Oil Sands unit-cost gains without shifting expense into capital or reclamation, reliable execution through the CEO/CFO transition, and evidence that refining/retail and logistics advantages protect returns through a weaker commodity cycle.

Kill / trigger criteria:

- Return-based research trigger: price at or below C$37.16 while the audited Base earnings path remains intact.
- Negative operating trigger: Oil Sands cash cost above C$35/bbl and production below 800 Mbbls/d for two consecutive quarters.
- Capital-allocation trigger: Base repurchases fall materially below the modeled C$4.0B-C$4.8B annual path without an offsetting debt, dividend or high-return investment benefit.
- Governance trigger: the CEO transition or permanent CFO appointment weakens disclosure, guidance discipline or capital-allocation controls.

Research sizing if actionable: None. The completed research does not propose capital, and explicit owner approval would be required for any future trade.

Appendix A - Company Primer

Suncor Energy Inc. â€” Company Primer

Ticker: SU.TO **Information date:** September 6, 2026 SGT **Latest completed quarter:** Q2 FY2026, ended June 30, 2026
Reporting currency: Canadian dollars; financial amounts are CAD millions unless stated otherwise

Purpose and source discipline

This appendix is an operating primer for a reader approaching Suncor for the first time. It explains how the assets, customers, cost structure, commodity exposures, and regulatory setting fit together. It is not a valuation, management-quality assessment, moat score, or investment recommendation.

All financial figures come from the sealed [quantitative foundation](C:/Users/Admin/OneDrive/GPT/ER%202.0/Suncor%20Energy%20Inc/quant_foundation.md), which reconciles the issuer's IFRS statements and applies official-filing overrides where live Financial Modeling Prep classifications differ. The quantitative foundation passed eight of eight reconciliation checks and the independent QF review. Operational descriptions, production routes, asset capacities, reserves, and regulatory facts are drawn from Suncor's live-filed [2025 Annual Information Form](https://www.sec.gov/Archives/edgar/data/311337/000110465926020411/su-20251231xex99d1.htm) and, where current-quarter context is useful, its [Q2 2026 filing](https://www.sec.gov/Archives/edgar/data/311337/000110465926090544/su-20260804xex99d2.htm). The distinction matters: Suncor reports gross revenue before royalties, while one FMP presentation is post-royalty, and its disclosed segment profit measure is earnings before income taxes rather than operating income.

Business overview: one system spanning the barrel

Suncor is a large Canadian integrated energy producer. Its chain begins with oil sands ore or underground bitumen deposits in northern Alberta and offshore crude fields near Newfoundland and Labrador. It then extends through extraction, upgrading, logistics, refining, wholesale distribution, and consumer-facing fuel retail. A separate supply, trading, and optimization organization connects these pieces by procuring feedstock, allocating barrels, using storage and pipeline capacity, managing inventories, and marketing products into the most attractive available outlets.

The simplest way to understand the company is as three operating businesses linked by physical infrastructure:

- **Oil Sands** mines or thermally produces bitumen, upgrades part of it into synthetic crude oil (SCO), blends the rest with diluent, and sells or transfers those barrels to refineries.
- **Exploration and Production (E&P)** produces conventional offshore crude in Atlantic Canada and retains international contractual interests in Libya and Syria, although the latter are politically constrained.
- **Refining and Marketing (R&M)** buys crude, converts it into gasoline, diesel, jet fuel, heating oil, asphalt, petrochemical products, and other outputs, and sells through wholesale, commercial, and retail channels.

The customer is different at each point. Upstream customers are predominantly refiners and commodity buyers that purchase crude or bitumen at market-linked prices. Refining customers include distributors, independent marketers, industrial and commercial users, farms, trucking fleets, airports, and paving customers. At the end of the chain, motorists and convenience-store customers buy Petro-Canada-branded fuel and merchandise. The product solves a basic logistics and conversion problem: hydrocarbons must be extracted, processed into transportable or usable form, moved to demand centres, refined to specification, and reliably supplied at thousands of consumption points.

Suncor does not sell this output through a software-like subscription or contracted recurring-revenue model. Crude sales are generally priced from daily or monthly market references, and E&P production is typically sold without long-term supply commitments. Refined products flow through a mix of direct sales, wholesale contracts, branded dealers, company-owned or leased retail stations, and commercial cardlock sites. Revenue therefore repeats because energy demand recurs, not because customers are contractually locked into multi-year payments.

Revenue and profit architecture

FY2025 gross revenue was CAD 52,377 million. The accounting mix can mislead a first-time reader because refining and marketing has the largest revenue base but passes substantial crude-feedstock cost through its sales, while Oil Sands generates more profit on a smaller reported revenue base.

FY2025 segment	Gross revenue	Share of consolidated gross revenue	Earnings (loss) before income taxes	Pretax margin
Oil Sands	19,298	36.8%	5,277	27.34%
Exploration and Production	2,509	4.8%	526	20.96%
Refining and Marketing	30,569	58.4%	2,822	9.23%
Corporate and Eliminations	1	0.0%	(677)	n/m
Consolidated	52,377	100.0%	7,948	15.17%

The three operating segments generated CAD 8,625 million of pretax earnings before CAD 677 million of Corporate and Eliminations expense brought the total to CAD 7,948 million. Corporate and Eliminations is not another customer business: it contains borrowing costs, unallocated expenses, certain clean-technology investments, and elimination of intersegment sales, principally crude feedstock sold by Oil Sands to R&M. This is why consolidated revenue should not be reconstructed by simply adding internal physical flows.

The trailing twelve months ended June 30, 2026 show the same architecture at a stronger recent earnings level: gross revenue of CAD 60,729 million and pretax income of CAD 12,029 million. Segment gross revenue was CAD 16,888 million for Oil Sands, CAD 3,223 million for E&P, and CAD 36,617 million for R&M, with CAD 1 million in Corporate and Eliminations. The associated segment pretax amounts were CAD 6,965 million, CAD 1,050 million, and CAD 5,523 million, before a CAD 1,509 million corporate and eliminations loss. These figures orient the reader to current scale; they do not imply a normalized run rate.

Oil Sands: mining, in situ production, and upgrading economics

Oil Sands is a collection of distinct production technologies rather than a single mine. Suncor wholly owns Base Plant Mine and Fort Hills and holds a 58.74% interest in Syncrude, which it operates. Its in situ assets include Firebag and MacKay River. Mining is used where the resource is close enough to the surface: oil sands ore is excavated, trucked, mixed with hot water, and separated into bitumen froth. In situ production is used for deeper deposits: steam-assisted gravity drainage injects steam underground so heated bitumen can flow to a producing well. This substitutes drilling and steam generation for trucks and extraction plants.

The distinction drives cost behaviour. Mining has large fixed systemsâ€”mobile fleets, crushers, extraction plants, tailings facilities, utilities, and labourâ€”so cost per barrel is sensitive to throughput and reliability. In situ operations avoid open-pit mining but consume natural gas and power to generate steam; the steam-to-oil ratio, reservoir quality, well performance, and gas price are central cost variables. Both require recurring sustaining capital and long planning cycles. Mining also carries substantial tailings, land reclamation, and water-management obligations.

Upgrading is the middle conversion step. Raw bitumen is heavy and viscous; moving it by pipeline generally requires blending with lighter diluent, and its quality often commands a discount to lighter crude. Base Plant's two upgraders can produce sweet and sour SCO and ultra-low-sulphur diesel, while Syncrude uses a fluid-coking process. As filed for 2025, Base Plant had combined nameplate capacity of 350 thousand barrels per day of SCO, and Syncrude capacity net to Suncor was 206 thousand barrels per day. Suncor also operates cogeneration at Base Plant, Firebag, Fort Hills, and Syncrude, with excess electricity sold to Alberta's grid.

Regional integration is unusually important. Base Plant is a hub: Fort Hills and in situ barrels can move to it, while bilateral pipelines connect Base Plant and Syncrude. A barrel can therefore be sold as diluted bitumen, transferred for upgrading, directed to a Suncor refinery, or sold to a third-party refiner. This flexibility can reduce lost production during planned maintenance, improve upgrader utilization, and capture a higher-quality product price when upgrading economics are favourable. It cannot eliminate physical constraints: an outage in extraction, a cokers' bottleneck, poor ore quality, extreme weather, pipeline restrictions, or a major turnaround can still remove high-margin volumes.

For FY2025, Oil Sands produced 799.4 thousand barrels per day, comprising 519.1 thousand barrels per day of upgraded SCO and diesel and 280.3 thousand barrels per day of non-upgraded bitumen after inter-asset transfers and consumption. Principal customers were refineries in North America and Asia. Product can move through Suncor-owned or third-party pipelines toward Edmonton, Hardisty, Suncor's own refineries, other North American refining hubs, and the west coast. These

routes broaden the marketing set, but realized prices still depend on global crude benchmarks, Canadian heavy-oil differentials, pipeline capacity, transportation cost, diluent economics, and the Canadian-dollar exchange rate.

A dollar of Oil Sands revenue is reduced first by royalties, then by energy, labour, maintenance, consumables, transportation, and operating costs; depreciation reflects the vast installed asset base. Alberta's royalty framework also makes government take price- and payout-sensitive. Because many operating costs are relatively fixed in the short term, incremental reliable production can carry attractive contribution economics, while downtime can be disproportionately expensive. FY2025 segment pretax margin of 27.34% illustrates the earnings power during that year's commodity and operating conditions, not a through-cycle constant.

Exploration and Production: smaller, conventional, and less integrated

E&P is much smaller than Oil Sands and R&M. Its Canadian portfolio comprises interests in Terra Nova, Hibernia and Hibernia Southern Extension, White Rose and its extensions, and Hebron. These offshore fields use floating or fixed production systems, with crude loaded onto shuttle tankers and sold directly or through a Newfoundland transshipment terminal. Suncor operates Terra Nova; several other interests are non-operated, which means partner execution, field-development decisions, and joint-venture governance matter alongside Suncor's own capability.

This segment has more conventional upstream economics. Revenue is the product of liftings, realized benchmark-linked price, quality, transportation, and foreign exchange. Royalties and field operating costs follow, while depletion recognizes consumption of a finite reserve base. Offshore economics are capital-intensive and lumpy: platforms, floating production systems, subsea equipment, drilling campaigns, life extensions, and safety systems require large commitments well before revenue. Field decline and turnaround timing can materially change unit costs because fixed infrastructure is spread across fewer barrels when production falls.

International assets do not carry equal economic weight. In Libya, Suncor is party to exploration and production sharing agreements with the National Oil Corporation. Production and liftings have been intermittent since 2013 amid political unrest; Suncor's remaining asset value was impaired in 2015, and force majeure remains relevant. Syrian operations have been suspended since 2011 under sanctions and political unrest, with the asset value impaired to zero in 2013. Those facts make E&P geographically more complicated than its revenue contribution suggests, but current operating economics are primarily Canadian offshore.

E&P generated only 4.8% of FY2025 gross revenue but 6.1% of the three operating segments' pretax earnings. Its FY2025 pretax margin was 20.96%. The mix can swing with crude prices, cargo timing, royalties, field uptime, and maintenance. Unlike Suncor's Alberta barrels, offshore cargoes are not physically integrated into the same regional upgrading hub, although the company's broader marketing organization can optimize destinations.

Refining and Marketing: conversion margin plus routes to the customer

R&M includes four refineriesâ€”Montreal, Sarnia, Edmonton, and Commerce City, Coloradoâ€”plus terminals, pipelines, wholesale networks, retail stations, commercial cardlocks, and product marketing. Filed 2025 nameplate capacities sum to 466 thousand barrels per day: Montreal 137, Sarnia 85, Edmonton 146, and Commerce City 98. Feedstock flexibility differs by plant. Edmonton is naturally positioned for western Canadian oil sands feedstocks; Sarnia and Montreal connect to eastern pipeline and marine systems; Commerce City runs U.S. and Canadian feedstocks and serves Colorado and Wyoming.

Refining economics are a spread business. Revenue reflects product volumes and prices for gasoline, diesel, jet fuel, heating oil, asphalt, petrochemical products, and other outputs. The largest input cost is crude. What matters economically is not a high product price alone but the difference between the value of the refined product slate and the delivered cost of feedstock, adjusted for energy, hydrogen, catalysts, labour, maintenance, environmental compliance, and distribution. Complex refineries can gain when discounted heavy or sour crude is available and their equipment can convert it into higher-value products. Conversely, narrow crack spreads, expensive feedstock, low utilization, or outages compress margins quickly.

This explains the segment's accounting profile. R&M produced 58.4% of FY2025 gross revenue but a 9.23% pretax margin. High revenue includes pass-through commodity value and should not be confused with low-quality economics; the relevant operating questions are refinery utilization, crack spreads, feedstock advantage, product yields, maintenance discipline, and channel margins. In 2025, all four refineries reported utilization around or above nameplate on the issuer's annual basis, illustrating that effective throughput can exceed nominal design capacity, though no single-year utilization rate is permanent.

The marketing network extends the margin capture. At December 31, 2025, Suncor supplied 1,732 Canadian retail stationsâ€”765 company-owned locations and 967 branded dealer sitesâ€”as well as 193 U.S. branded stations and 319

Petro-Pass commercial cardlock sites. Wholesale operations serve agriculture, home heating, paving, small industrial, commercial, trucking, and large industrial customers. Convenience-store sales and car washes add non-fuel revenue at retail. Suncor also owns or accesses terminals and pipelines that move refined products to regional demand centres.

Seasonality matters: gasoline demand tends to be strongest during summer driving; heating oil in winter; diesel during drilling and agricultural seasons; and asphalt during summer construction. Suncor can alter refinery feedstocks and yields, import or export products, use inventory, or buy third-party refined product to meet commitments during maintenance. This turns logistics into an economic capability: the company is not merely producing molecules but managing time, location, specification, and reliability.

Customers, channels, and commercial concentration

Suncor's channel structure is diversified by customer type rather than by recurring contract form. Oil Sands and E&P sell into liquid commodity markets where benchmark pricing limits customer-specific pricing power. The natural counterparties are refiners, marketers, traders, and other industrial buyers. Credit exposure exists, but demand is not dependent on one branded enterprise customer in the way a concentrated business-to-business supplier might be.

Downstream, the customer base fans out. Retail motorists buy at posted prices; branded dealers and independent sites take supplied fuel; Petro-Pass serves fleets; wholesalers deliver into commercial and regional niches; and direct industrial customers buy large volumes. Suncor's own stations, third-party branded sites, terminals, and pipelines form a multi-channel distribution system. The Petro-Canada brand and loyalty relationships can influence site traffic, but commodity cost and local price competition remain powerful. The channel advantage is therefore chiefly one of reach, supply assurance, logistics, and optimization rather than an ability to set prices independently of the market.

Supply, Trading and Optimization coordinates seven major commodity groups from offices in Canada, the United States, and the United Kingdom. It allocates crude and feedstocks, manages natural-gas supply, arranges reciprocal exchanges, moves products to domestic and international markets, and manages inventory and price exposure. Trading should be understood as an enabler of physical assets, not a fourth reportable profit engine in the QF segment table.

Capital intensity, maintenance, and asset lives

Suncor must continually spend merely to preserve safe, compliant production. Mining fleets and extraction trains wear; upgrader coke drums and furnaces require replacement; tailings infrastructure expands; SAGD wells and steam systems need sustaining work; offshore fields require drilling and life extensions; and refineries undergo planned turnarounds. Growth and debottlenecking capital sit on top of that base. Projects have long lead times, engineering risk, scarce-labour exposure, regulatory dependencies, and sensitivity to inflation in the Wood Buffalo region.

The QF quantifies this burden. FY2025 operating cash flow was CAD 12,781 million and capital expenditures were CAD 5,856 million, equal to 45.8% of operating cash flow; free cash flow before other financing and shareholder distributions was CAD 6,925 million. For the TTM ended June 30, 2026, operating cash flow was CAD 15,796 million and capital expenditures CAD 5,469 million, or 34.6% of operating cash flow, leaving CAD 10,327 million of free cash flow on the QF definition. These ratios move with commodity prices and working capital; they do not measure maintenance capital precisely. They do demonstrate that capital spending is structurally material even when operations are generating substantial cash.

Oil sands asset lives are unusually long compared with conventional shale or short-cycle wells. The independent reserves evaluation effective December 31, 2025 reported 4.743 billion gross barrels of proved reserves and 7.440 billion gross barrels of proved-plus-probable reserves, all in Canada. Net volumes were 4.125 billion and 6.265 billion barrels, respectively. Mining plus in situ accounted for nearly all of the proved-plus-probable total; E&P Canada contributed 247 million gross barrels. Reserve estimates are not guaranteed recoveries or fair value and rely on forecast prices, costs, development plans, and technical judgments.

The long reserve base does not mean the installed system can run indefinitely without reinvestment. Mine faces must advance; depleted ore areas must be replaced; tailings and water systems require approvals and capital; new in situ pads must be drilled; and offshore production must be supported by new wells or extensions. Suncor's 2025 milestones illustrate the distinction between resource life and equipment life: the Mildred Lake Mine Extension West reached first ore to sustain Syncrude feed, while the completed Upgrader 1 coke-drum project was expected to extend that facility's life by 30 years. Long-lived resources increase the value of reliable infrastructure, but they also extend decommissioning, reclamation, and carbon-policy exposure far into the future.

Commodity and competitive context

Suncor competes at several layers simultaneously. In upstream markets, realized price depends on global crude supply and demand, OPEC+ actions, North American inventories, refinery demand, transportation availability, and the WTI/WCS and quality differentials. Oil sands output has low natural decline once facilities are operating, but high fixed costs can encourage continued production through weak prices. That makes short-cycle global producers and lower-cost conventional barrels relevant price-setters even though Suncor's physical asset base is very different.

Within oil sands, competitors vie for pipeline capacity, skilled labour, contractors, maintenance windows, and future approvals. The physical network can create both rivalry and interdependence: third-party pipelines, storage, and refineries are necessary outlets, while Suncor may also buy third-party bitumen or refined product when doing so improves utilization or meets customer demand. Extreme weather, forest fires, electricity interruptions, and shared infrastructure outages can affect multiple operators together.

In refining, competition is regional and margin-driven. Refineries compete for advantaged crude and for product demand within the reach of their pipelines, terminals, rail, trucking, and marine routes. Imports can cap local margins; exports can relieve oversupply. New entrants are less common because refineries are expensive and difficult to permit, but existing capacity can change runs quickly. Electric-vehicle adoption, efficiency, biofuel blending, and economic activity influence long-run liquid-fuel demand, while aviation, trucking, petrochemical, paving, and industrial uses have different substitution paths.

The Canadian dollar is a cross-cutting variable. Crude benchmarks are commonly set in U.S. dollars while much of Suncor's cost base and reporting are Canadian-dollar denominated. A weaker Canadian dollar can support translated upstream realizations but also raises the cost of imported equipment, feedstock, or services. Natural-gas prices matter as a major energy input to steam generation and hydrogen/refining processes, partly offset by cogeneration and electricity sales.

Regulatory and environmental setting

Suncor operates under federal, provincial, state, municipal, offshore, and securities regimes. The economic burden enters through royalties, carbon pricing, fuel specifications, renewable-content requirements, air and water permits, tailings management, land disturbance, worker and process safety, Indigenous consultation, reclamation security, and eventual decommissioning.

Alberta's oil sands royalty system is project-specific and changes with prices and payout status. The 2025 AIF describes a net-revenue royalty sliding from 25% to 40%, subject to a 1% to 9% gross-revenue minimum depending on benchmark crude price. A project remains in the pre-payout phase until cumulative revenue exceeds cumulative allowed costs and investment allowances. In 2025, Fort Hills remained pre-payout, while Base Mine, MacKay River, Firebag, and Syncrude were post-payout. This causes royalties to respond nonlinearly to both price and cumulative project economics.

Carbon rules differ by jurisdiction and may change. Alberta's Technology Innovation and Emissions Reduction system applies to large industrial emitters and permits compliance through performance credits, offsets, or fund payments. Federal clean-fuel rules require reductions in the carbon intensity of gasoline and diesel and can create both compliance costs and credits. Ontario performance standards cover Sarnia and the St. Clair ethanol plant; Quebec's cap-and-trade system covers Montreal facilities and distributed fuels; Newfoundland and Labrador applies performance standards to offshore installations; and Colorado imposes facility-specific requirements on Commerce City. These policies affect operating cost, capital allocation, product blending, and the economics of cogeneration, renewable fuels, efficiency projects, and carbon capture.

Water and tailings are long-duration obligations. Alberta's Lower Athabasca frameworks cover water, groundwater, air, and tailings, while a regulatory framework for the safe release of treated mine water remains under development. The absence or delay of an accepted treatment-and-release route can increase storage needs and complicate reclamation. Indigenous rights and consultation requirements also affect permits, project schedules, land use, and relationships with communities; they are not peripheral to operating continuity.

Environmental policy creates a two-sided exposure. Higher carbon and fuel-compliance costs can penalize emissions-intensive extraction and refining. At the same time, cogeneration can lower power-related emissions intensity, solvent-assisted SAGD may reduce steam and water needs, and government incentives can improve the economics of carbon capture and other abatement. These technologies still require capital, regulatory clarity, reliable execution, and in some cases shared infrastructure. A primer should therefore treat decarbonization as an operating and capital-allocation problem, not assume either effortless compliance or inevitable asset stranding.

How integration changes cycle exposure

Integration moderates, but does not remove, commodity cyclicality. When heavy Canadian crude is deeply discounted, the Oil Sands business receives a lower external price, but refineries capable of processing discounted feedstock may earn a stronger input advantage. When crude prices rise rapidly, upstream earnings can expand while refining feedstock becomes more expensive and product demand or crack spreads may lag. The two sides are not a perfect hedge: product cracks, crude quality, refinery configuration, regional logistics, inventory timing, outages, royalties, and foreign exchange all move independently.

Suncor's most valuable integration is physical optionality. It can upgrade some bitumen, blend some for sale, transfer crude internally, choose among pipelines and storage points, alter refinery feedstocks and yields, export or import refined products, and purchase third-party barrels during maintenance. Internal transfers preserve economic exposure even when accounting eliminates the revenue. The marketing system can also capture location and timing spreads that a pure producer would leave to others.

There are limits. A major common-mode outage at Base Plant, regional pipeline disruption, poor mine conditions, or a broad demand shock can hit several links at once. Upgrader utilization is not valuable if extraction cannot supply feed; retail reach does not protect against structurally weak fuel margins; and owned refineries do not absorb all upstream production. Integration also adds complexity and maintenance coordination across mines, steam plants, upgraders, pipelines, terminals, refineries, and retail networks.

The correct cycle lens is therefore a portfolio of linked margins:

- **Upstream margin:** benchmark crude price minus quality differential, transportation, royalties, and operating cost.
- **Upgrading margin:** value uplift from converting bitumen into SCO or diesel minus diluent, energy, operating, and maintenance cost.
- **Refining margin:** product realization minus delivered feedstock and conversion cost.
- **Marketing and logistics margin:** value from location, timing, storage, distribution, branded channels, and supply reliability.

In some environments these margins offset; in others they reinforce. Strong crude, wide refining cracks, reliable operations, and open takeaway can lift several links together. Conversely, weak crude pricing combined with outages or poor product demand can compress the whole system. The integration thesis is consequently about widening the set of profitable choices and improving resilience, not guaranteeing stable earnings.

Orientation for the main analysis

Suncor should be read first as a long-lived, capital-intensive physical system and only second as a set of accounting segments. R&M dominates revenue because it sells high-value finished products with crude cost embedded, while Oil Sands has historically supplied more segment profit. E&P is smaller and more conventional, with offshore decline and joint-venture features. The most important operating variables are asset reliability, throughput, oil-sands differentials, refinery cracks, gas and power costs, royalty status, maintenance timing, and access to logistics.

The long reserve base supports decades of potential production, but realizing that potential requires continuous capital, replacement mine areas and wells, environmental compliance, and social licence. Integration adds valuable routing and conversion choices and can cushion some commodity moves, yet it cannot turn Suncor into a non-cyclical business. Those are the structural facts a reader should carry into the later competitive, management, valuation, and risk work.

Appendix M - Management Assessment

Suncor Energy Inc. â€” Management Assessment

Assessment date: 6 September 2026 **Management gate: YELLOW Scope:** Management, capital allocation, disclosure and governance only. Financial history is from the DR-cleared `data_package.md` and `quant_foundation.md`; current management, governance, compensation, calls and peer evidence are from live primary sources archived in the M run manifest.

1. Who is running the company

Suncor is presently between a proven operating reset and an unusually consequential hand-off. Rich Kruger has been President and CEO since April 2023. Before Suncor he spent almost four decades at ExxonMobil and Imperial Oil, including serving as Imperial's CEO from 2013 to 2019. He therefore owns the current safety, reliability, cost and capital-return operating system rather than merely inheriting it. Yet he will cease being CEO in April 2027 and become Executive Vice Chair.

The [6 August 2026 leadership announcement](https://www.sec.gov/Archives/edgar/data/311337/000110465926091680/tm2622191d2_ex99-1.htm) names Peter Zebedee as President and CFO effective 14 September 2026 and CEO effective April 2027. Zebedee joined Suncor in 2022, currently leads Upstream and previously led LNG Canada; his earlier career included Shell, Petro-Canada and Syncrude. That is credible operating preparation, but it is not yet a demonstrated public-company CEO or CFO record. Troy Little, appointed CFO after Kris Smith's retirement, is no longer with the company. The release gives no reason and identifies no separate permanent finance leader after Zebedee becomes CEO. On the assessment date, the disclosed permanent succession plan therefore contains a short gap before Zebedee starts and a longer unresolved question: who will be the independent CFO once he takes the chief executive role?

The same announcement elevates two long-serving internal operators on 14 September. Adam Albeldawi, with more than 20 years at Suncor and recent responsibility for in-situ operations, becomes EVP Upstream. Shelley Powell, a 30-year Suncor veteran, becomes EVP Development and Projects. Dave Oldreive continues to lead Downstream. This is a sensible blend: Zebedee, Albeldawi and Powell have asset-level memory, while Kruger's Executive Vice Chair role preserves continuity. It also concentrates succession risk in an internally promoted team whose performance under the new accountability structure remains unobserved.

Russ Girling is the independent board chair. The [2026 proxy](https://www.sec.gov/Archives/edgar/data/311337/000110465926020414/tm261271d1_ex99-1.htm) shows ten directors elected at the 2026 AGM, nine independent; Kruger is the only non-independent director. Independent directors meet in camera at every board and committee meeting, and none was classified as overboarded under the proxy's ISS and Glass Lewis tests. Director support ranged from 92.12% to 99.16%, while say-on-pay received 94.72%. The structure is credible, but the quality of its succession decision can only be judged after Zebedee runs the company and the board installs a durable CFO.

2. Tenure, record and the three largest decisions

Kruger's roughly three-and-a-half years in seat are long enough to assign him the present strategy and operating culture. Three decisions dominate the record.

First, he made safety, reliability and accountability the operating system. The proxy reports 2025 lost-time incident frequency of 0.02, down 42%; recordable injury frequency of 0.28, down 15%; and process-safety event frequency of 0.09, down 31%. It also says Suncor exceeded its initial 2025 guidance by 35,000 bbl/d of upstream production, 38,000 bbl/d of refinery throughput and 53,000 bbl/d of refined-product sales. The data package confirms the economic record is strong but commodity-sensitive: operating margin was 17.68% in FY2023, 17.82% in FY2024 and 16.35% in FY2025; standardized ROIC was 11.85%, 11.92% and 9.95%. Management deserves credit for record physical performance, not for pretending that an oil producer controls price. Lower FY2025 margin and ROIC despite execution improvement is precisely why the operating record should be judged with volumes, unit cost and free cash flow as well as headline earnings.

Second, management simplified the portfolio and made Fort Hills an operated, 100%-owned core asset. Suncor acquired the remaining Fort Hills interests in 2023 while disposing of its UK exploration and production portfolio and renewable-power assets. The observable result is operational rather than a clean acquisition return calculation: Fort Hills

achieved record 2025 production of roughly 175,000 bbl/d and demonstrated approximately 220,000 bbl/d stream-day capacity. The data package's FMP `acquisitionsNet` field is a cash-flow sign convention, not transaction consideration, so it cannot support a fabricated deal IRR. The prudent conclusion is that control and simplification helped reliability, but the consolidated disclosures do not isolate Fort Hills revenue, margin or ROIC sufficiently to prove the price paid created per-share value.

Third, Kruger linked a lower debt level to aggressive per-share returns while constraining annual capital. The 2026 Investor Day scorecard says Suncor achieved its earlier commitments one year ahead of schedule: normalized free funds flow improved C$3.3 billion versus 2023, the WTI breakeven fell US$10/bbl, production grew 114,000 bbl/d and annual capital was C$5.7 billion. The diluted weighted-average share count fell from 1,489 million in FY2021 to 1,220 million in FY2025, an 18.1% reduction. The framework now avoids false precision: on the Q2 2026 call, management described approximately one-times net debt to cash flow at US$50 WTI as a guardrail rather than an absolute debt target, and increased repurchases to C$500 million per month while retaining the ability to moderate in a downturn.

What failed? There is no disclosed Kruger-era capital disaster or quiet write-off. The visible misses have been operating disruptions: third-party gas and coker issues in Q1 2026 and unprecedented Q2 weather that management estimated reduced production by 50,000â€“60,000 bbl/d. Management acknowledged both, quantified the Q2 weather effect, described mitigation and retained full-year guidance. The larger blemish is people continuity. Little's unexplained departure after a short CFO tenure interrupts an otherwise deliberate plan; this is not evidence of wrongdoing, but it is too material to dismiss.

3. Capital allocation behavior

The required five-year record, reproduced only from the DR-cleared data package, is:

Fiscal year	Capex (C$bn)	Capex / FMP revenue	R&D	Buybacks (C$bn)	Dividends (C$bn)	`acquisitionsNet` (C$bn)
2021	4.555	11.64%	Not separately disclosed	2.304	1.550	+0.335
2022	5.120	8.78%	Not separately disclosed	5.135	2.596	+0.315
2023	5.828	11.87%	Not separately disclosed	2.233	2.749	(0.512)
2024	6.483	12.79%	Not separately disclosed	2.908	2.803	+0.051
2025	5.856	11.97%	Not separately disclosed	3.129	2.809	+0.066

The `acquisitionsNet` series uses negative numbers for net cash outflow and positive numbers for inflow or recovery; it is not gross M&A value. Across FY2021â€“FY2025, Suncor spent C$15.709 billion on repurchases and C$12.507 billion on dividends. FY2025 issuer-defined capital comprised C$3.162 billion of sustainment and maintenance plus C$2.496 billion of economic investment, excluding C$0.198 billion of capitalized interest. In H1 2026, Suncor spent C$2.466 billion on capital including capitalized interest, paid C$1.418 billion of dividends and repurchased C$1.875 billion of shares while repaying C$0.378 billion of debt.

This behavior matches the stated strategy: maintain long-life integrated assets, fund high-return debottlenecking and technology, then return excess cash. The pattern is not a sequence of empire-building acquisitions. Full control of Fort Hills and tighter integration with Suncor's downstream network were accompanied by peripheral divestitures. The current plan targets more than 100,000 bbl/d of incremental upstream output, a further US$5/bbl reduction in enterprise breakeven and C$2 billion of incremental annual free funds flow over three years, while keeping capital below C$6 billion annually.

Buybacks have been ratable, not demonstrably valuation-timed. The cadence rose from C$275 million to C$350 million and then C$500 million per month as balance-sheet capacity and cash flow strengthened. That makes the program responsive to financing capacity, but not to an explicit share-price hurdle. Still, the share-count evidence matters: repurchases more than offset stock compensation and reduced diluted shares materially. This is genuine per-share accretion behavior, though the board should disclose a valuation discipline alongside its leverage guardrail.

4. Compensation alignment

The proxy's design is materially better than the common energy-industry practice of rewarding volume growth without a return constraint.

Element	2025 design	Assessment
Annual incentive plan	Eight metrics in three equally weighted categories: safety/environment, reliability/volumes, and financial/expenses; minimum adjusted-funds-from-operations gate; 200% cap	Balanced and cash-gated, but a 1.93 corporate factor in a record year shows high payout sensitivity
Long-term incentive	45% market PSUs, 5% climate PSUs, 25% RSUs, 25% options	Multi-year and substantially performance-linked
Market PSU score	Three-year relative TSR 70%, ROCE 30%	Per-share market outcome dominates; ROCE supplies a real capital-efficiency check
2026 LTI change	50% market PSUs, 5% climate PSUs, 25% RSUs, 20% options	Slightly less option leverage; no weakening of return discipline

Kruger's 2025 salary was C$1.35 million, annual incentive C$3.908 million and equity award C$10.125 million; more than 85% of total direct compensation was at risk. The board did not override the formulaic 1.93 corporate result. Clawbacks include the mandatory Rule 10D-1 policy; hedging and short selling are prohibited; loans and option repricing are prohibited; and change-of-control severance is double-triggered and capped at two times cash pay.

The ownership optics require nuance. At the proxy date Kruger owned **zero actual common shares**, 63,083 deferred share units and 314,023 unvested RSUs. Shares plus DSUs were valued at C$3.843 million, versus C$22.973 million including RSUs. The guideline is six times salary and permits post-2025 RSUs to count only after at least 25% of the guideline is met with shares and DSUs; he was reported compliant. This is economic exposure, but it is not the same as founder-style after-tax common-share ownership. Zebedee held 6,159 shares, 26,244 DSUs and 31,964 RSUs. Little held no shares or DSUs and 8,878 RSUs at year-end, though his compliance deadline had not arrived.

Company-wide SBC was C$0.510 billion in FY2024, C$0.473 billion in FY2025 and C$0.650 billion in the twelve months ended June 2026â€”roughly 1% of revenue, with no chronic dilution. The diluted share count's 18.1% fall from FY2021 to FY2025 is decisive. Incentives are strong overall, but Kruger's lack of actual common shares keeps alignment short of exemplary.

5. Disclosure quality and candor: last eight calls

Eight consecutive quarters were reviewed using issuer transcripts where available and fresh live FMP captures for redundancy. FMP returned an empty Q1 2026 response twice; the official issuer transcript replaced it. The official Q4 2025 transcript was not surfaced in the current issuer archive search, so the live FMP transcript was cross-checked to the annual-results context. This is a source limitation, not a silent substitution.

Quarter	Difficult topic and response	Guidance / candor assessment
Q3 2024	Production, refining and product sales tracked above guide; capital at or below low end	Direct, quantified operational update
Q4 2024	Kruger admitted December performance exceeded even his own estimate; 2024 capex was C$0.2bn below midpoint	Transparent about forecast error and heavier 2025 maintenance
Q1 2025	Maintenance, policy and macro uncertainty	Used qualifiers but distinguished what was known from what was not
Q2 2025	Turnaround execution and capital needs	Cut annual capital guide by C$0.4bn to C$5.7â€“5.9bn and gave operating detail
Q3 2025	Whether initial guidance had been conservative	Said it was not intentionally conservative; raised volume ranges after execution improved
Q4 2025	Repeatability of record results	Reported performance above the high end of guide for a second year; tied next phase to internal growth
Q1 2026	Working-capital change, net debt and marketing repeatability	Quantified movements; said the jury remained out where market outcomes were genuinely variable
Q2 2026	Weather-driven miss and payout acceleration	Quantified a 50â€“60 kbbl/d impact, explained mitigation, held guide and stated the US$50 WTI leverage guardrail

Literal hedge markers such as â€œheadwind,â€■ â€œuncertainâ€■ or â€œtoo earlyâ€■ appeared somewhere in seven of eight transcript texts. Manual review found **zero quarters in which those words evaded a load-bearing operating or capital question**. They generally described macro conditions, policy or project timing; answers on controllable items supplied volumes, cost/capital ranges, causal explanations or explicit limits. The evidence is unusually good: management has

repeatedly raised or exceeded operating guidance, cut capital guidance when execution allowed and acknowledged outages rather than burying them in an adjusted metric. The remaining concern is transition disclosure. Saying only that Little is â€œno longer with the companyâ€■ does not meet the otherwise high standard of candor for a sudden CFO departure.

6. Strategic coherence

The [2025 MD&A](https://www.sec.gov/Archives/edgar/data/311337/000110465926020411/su-20251231xex99d3.htm) says Suncor aims to be Canada's leading energy provider, respected for its people, performance, sustainability and relationships. Its practical strategy is more concrete: improve safety and reliability, build a cost structure resilient below US$45 WTI, exploit integration between long-life upstream assets and refining/marketing, decarbonize the base business and grow free funds flow per share.

Investment behavior supports that identity. Approximately half of 2025 capital was sustainment, with the balance directed to economic projects rather than a new geography or unrelated growth platform. Fort Hills consolidation, UK E&P and renewables exits, debottlenecking and internal growth all reduce organizational breadth. The Investor Day destinationâ€”more output, a lower breakeven and C$2 billion more annual free funds flow within the existing sub-C$6 billion capital envelopeâ€”is measurable. Management also speaks directly about threats it can influence: mine and plant reliability, weather readiness, natural-gas constraints, turnaround execution and cost. It is less explicit about long-run demand and carbon-policy scenarios on earnings calls, but the annual filings address them. This is coherent, not a rolling set of pivots.

7. Governance flags

There is one class of common shares, no dual-class founder control and no disclosed holder above 10% in the proxy. The Petro-Canada Public Participation Act limits individual ownership to 20%, further reducing control concentration. Directors and executive officers held 268,801 actual sharesâ€”only 0.02% of outstanding sharesâ€”and 862,197 shares plus DSUs at 24 February 2026. This low actual ownership is a soft alignment concern, not a minority-rights defect.

The proxy and [2025 AIF](https://www.sec.gov/Archives/edgar/data/311337/000110465926020411/su-20251231xex99d1.htm) disclose no material related-party transaction or management interest in a transaction affecting Suncor during the covered period. The MD&A reports disclosure controls and internal control over financial reporting effective at 31 December 2025, with KPMG attesting and no material change identified. No material restatement or enforcement matter was found in the reviewed issuer filings. A complete primary-source SEDI transaction ledger could not be captured in this run, so the last-twelve-month insider-selling pattern is **not rated**; proxy ownership is only a point-in-time snapshot and third-party aggregators were deliberately excluded. That evidence gap does not drive the gate, but it should be closed in the next proxy/SEDI refresh.

8. Peer comparison

Peer and CEO	Relative stewardship assessment
Canadian Natural Resources â€” Scott Stauth	CNRL's [2025 disclosure](https://www.sec.gov/Archives/edgar/data/1017413/000101741326000018/cnq-20251231.htm) explicitly targets per-share production, reserves, cash flow and net asset value and rests on a longer institutional record of balancing development, acquisitions and distributions. It remains the benchmark for cycle-tested capital consistency. Kruger's recent operating reset is at least comparable in clarity, but shorter in duration.
Cenovus â€” Jon McKenzie	Cenovus's [2025 MD&A](https://www.sec.gov/Archives/edgar/data/1475260/000147526026000008/a2025managementsdiscussion.htm) emphasizes safety, cost, debt targets and bottom-of-cycle project returns. Suncor ranks ahead on recent reliability improvement, guidance delivery and quantified call candor; neither should be credited with peer-superior acquisition returns without deal-level evidence.
Imperial Oil â€” John Whelan	Imperial's [2025 filing](https://www.sec.gov/Archives/edgar/data/49938/000004993826000009/imo-20251231.htm) shows disciplined payouts and strong operations, but Whelan has been CEO only since May 2025 and ExxonMobil owns 69.6%, limiting direct governance comparability. Suncor offers better minority independence; Imperial offers a deeply embedded owner-operator capital system.

On five-year stewardship, Suncor ranks behind CNRL's longer demonstrated capital record, ahead of Cenovus on recent execution, and difficult to compare cleanly with controlled Imperial. On communication, Kruger's direct, quantified answers rank at or near the top of this group. The weakness is continuity: all the evidence belongs mainly to a CEO who has announced his exit date.

9. Verdict on the management gate

YELLOW. Kruger has earned high marks for safety accountability, operational reliability, capital restraint, per-share shrinkage and candid disclosure; the incentives and independent-board structure reinforce rather than contradict that record. This is not a FAIL: there is no evidence of serial value-destructive M&A, chronic dilution, load-bearing evasiveness, weak controls or material minority-shareholder abuse. It is not yet a PASS because the April 2027 CEO succession transfers the strategy to an executive with no public CEO/CFO track record at Suncor, the former CFO left abruptly without explanation, and no durable post-transition CFO has been identified.

Upgrade to **PASS** if (1) a credible permanent CFO is named and the dual-hat transition is resolved; (2) Zebedee's first four reported quarters as President/CFO and then CEO sustain safety, volume, cost and project delivery within the sub-C$6 billion capital envelope; and (3) the return/debt framework remains stable through weaker oil without a large acquisition. Downgrade to **FAIL** if another unexplained senior departure or prolonged CFO gap emerges, if management accelerates M&A or growth without quantified per-share return hurdles, or if material safety regression, repeated guidance misses, project overruns or opportunistic changes to the debt-and-return rules show that Kruger's operating system did not survive him.

Source provenance

Fresh transcript files and the live primary-source capture are preserved under `raw/pulse-cio-20260906T220342+0800/m/`. The M-specific manifest is `raw/pulse-cio-20260906T220342+0800/m_source_manifest.json`; the shared `source_manifest.json` was intentionally not edited during concurrent production. Historical financial and capital-allocation figures come exclusively from the DR-cleared data package and quant foundation.

Appendix W - Moat and 2046 Durability

Suncor Energy Inc. â€” Moat and 2046 Durability

Ticker: SU.TO **Information date:** 2026-09-06 SGT **Twenty-year test date:** 2046-09-06 **Historical anchor:** TTM ended 2026-06-30

Source discipline and conclusion upfront

All Suncor historical figures, margins, capital data, and verified management facts in this appendix come only from the DR-cleared `data_package.md` and its sealed statutory bridge. External sources are used solely for industry competition, regulation, and transition context; archived copies and hashes are recorded in the W-specific source manifest. The segment appendices were still in-progress stubs at finalization, so no claim depends on them.

Suncor owns a defensible *operating position*: a long-life oil-sands resource base connected to sunk extraction, upgrading, logistics, refining, and retail infrastructure that would be extraordinarily difficult to recreate. It is not a classic economic moat that lets Suncor set price or compound at high returns independent of the cycle. Customers can switch barrels or fuel stations, competitors possess comparable assets, and global crude and refining spreads determine much of the profit pool.

1. Moat taxonomy applied

Network effects â€” absent. More customers do not make a Suncor barrel more valuable to the next customer, and more production does not create a self-reinforcing demand network. The retail and Petro-Pass footprints improve convenience and distribution density, but they do not create a two-sided platform. Scale may lower logistics cost; it does not generate a network effect.

Switching costs â€” low for products, moderate only in physical relationships. Crude, bitumen, gasoline, diesel, and jet fuel are specification-based commodities. Refiners can substitute suppliers subject to quality and logistics; motorists can choose another station. Heavy-crude configuration, dealer branding, or terminal connections create local friction, not enterprise-wide lock-in or durable price premiums.

Scale economies â€” real but shared. Suncor spreads fixed mine, upgrader, refinery, maintenance, procurement, engineering, trading, and compliance capabilities across large volumes. Its integrated system can route bitumen among blending, upgrading, internal refining, storage, and third-party sale, increasing the number of profitable choices. Operating learning matters because reliability and utilization determine unit cost in high-fixed-cost plants. Yet Canadian Natural, Cenovus, and Imperial also operate very large oil-sands or integrated systems. Canadian Natural describes its own mining/upgrading assets as long-life, low-decline and backed by extensive leases [W6]. Scale is therefore a necessary cost position, not a Suncor-only advantage.

Brand â€” useful downstream, weak upstream. Petro-Canada and Petro-Pass can attract retail and fleet traffic, while site density and loyalty relationships can lift convenience and non-fuel sales. Brand does not materially differentiate an upstream barrel, and local fuel prices remain visible and competitive. This is a distribution asset with modest consumer preference, not luxury-style pricing power.

Regulatory barrier and social licence â€” high entry barrier, mixed incumbent protection. New mines, tailings facilities, upgraders, pipelines, and refineries require scarce permits, consultation, environmental approvals, capital, and years of execution. That makes greenfield replication improbable and raises the replacement value of Suncor's installed base. But regulation is two-sided: the same permits, carbon obligations, reclamation duties, water constraints, and Indigenous relationships can restrict output or require capital. Canada's Clean Fuel Regulations already use a credit market and reward lower lifecycle carbon intensity, low-carbon fuel supply, and advanced-vehicle energy [W4]; the federal oil-and-gas emissions cap remains described in current federal guidance as forthcoming [W4], with the published proposal contemplating a cap-and-trade system [W3]. Incumbency is therefore a barrier to entry, not a perpetual licence to earn excess returns.

IP and patents â€” not material to the moat. Suncor benefits from process know-how in extraction, upgrading, steam management, reliability, autonomous haulage, trading, and refinery optimization. Most relevant technologies are available to peers, vendors, and joint ventures; no evidence in the cleared package identifies a patent estate that blocks competitive production. The defensible element is tacit operating experience embedded in complex sites, not exclusive intellectual property.

High-trust procurement and reliability â€” moderate. Large industrial buyers, airlines, fleets, dealers, and wholesale customers value specification, safety, delivery reliability, credit capacity, and assured supply. Suncor's refineries, terminals, storage, trading capability, and retail network make it credible during outages or regional imbalances. The benefit is strongest in R&M and logistics. However, trust rarely gives the supplier freedom to ignore market benchmarks, crack spreads, or nearby station prices.

The taxonomy yields three genuine advantagesâ€”scale/learning, hard-to-replicate physical infrastructure, and reliable distributionâ€”but no network effect, meaningful upstream switching cost, or proprietary-price umbrella. Those advantages lower cost and improve margin capture; they do not sever earnings from commodity and capacity cycles.

2. Per-segment moat

Oil Sands

The segment's moat-like asset is the combination of a roughly 20-year calculated net proved-plus-probable reserve life, low natural decline at operating facilities, installed extraction/upgrading capacity, and interconnections among Base Plant, Syncrude, Fort Hills, in situ assets, pipelines, storage, and refineries. A new entrant would need enormous capital, decades of permits and consultation, a resource position, specialized labour, and a route to market. Suncor also has cumulative operating knowledge across ore quality, steam, coke drums, turnarounds, tailings, and extreme weather. This advantage should remain operationally relevant for 10-20 years if reliability and sustaining investment hold.

What it does *not* provide is control over WTI, WCS differentials, global marginal supply, gas and power costs, royalties, or carbon policy. The segment's FY2021-FY2025 pretax margin ranged from 18.4% to 36.7%, and its cash costs differ materially by asset; that variability is the signature of operating leverage and commodity rent, not a stable franchise spread. Earliest break signal: a three-year rise in inflation-adjusted unit cash cost and sustaining capital per barrel while availability falls, especially if emissions-compliance cost grows faster than realized netback. A second warning is repeated delay or denial of replacement mine, tailings, water, or in situ-pad approvals.

Exploration and Production

E&P has reservoir access, offshore platforms, experienced crews, and partner relationships, but its economics are conventional and depleting. Several assets are non-operated, offshore fixed costs rise as fields decline, and international interests are exposed to sanctions and political interruption. Its five-year pretax margin fell from 74.4% in FY2022 to 21.0% in FY2025; the asset mix also changed after the U.K. divestiture. This is not persistent moat evidence. Durability is best described as 5-10 years around existing infrastructure and sanctioned tie-backs, not 20 years without successful reserve replacement. Earliest break signal: declining production despite development spending, rising unit depletion/operating cost, or partner deferral of life-extension projects.

Refining and Marketing

R&M's advantage is regional conversion and distribution: four refineries, heavy-crude capability, terminals, pipelines, trading, 1,732 supplied Canadian retail stations at FY2025 year-end, and 319 Petro-Pass sites. Feedstock flexibility and internal barrel routing can capture location, quality, inventory, and timing spreads. Greenfield refining is difficult to permit, and the 2025 Canadian refining map shows only about 1.93 million bbl/d of national capacity spread across a limited set of incumbents [W5]. That scarcity supports the value of existing sites.

The protection is regional rather than absolute. Imports and exports arbitrage shortages, incumbents compete, and EVs reduce road-fuel demand. R&M's FY2021-FY2025 pretax margin ranged from 8.3% to 15.5% and gross margin per barrel moved widely with cracks. The network should retain value for 10-15 years, especially in diesel, aviation, asphalt, industrial products, convenience retail, and low-carbon fuels, but gasoline-linked assets face a shrinking pool by 2046. Earliest break signal: utilization and product sales fall together for several years while non-fuel margin fails to offset weaker gasoline demand.

Blended company

The blend is weaker than the strongest asset. Oil Sands produced the largest FY2025 operating-segment pretax profit, but it is commodity-priced; R&M represented 58.4% of FY2025 gross revenue but earns a cyclical conversion spread; E&P is small and depleting. Integration dampens some differentials and preserves optionality, yet it can also create common-mode outage and capital complexity. The shareholder owns linked cyclical margins, not a recurring-price franchise.

3. Margin persistence evidence

The cleared package provides five clean annual years, not ten; this limitation prevents a full 10-year margin-persistence test. The available evidence is sufficient to show cyclicality, not sufficient to prove a narrow durable margin band. Consolidated operating margin below uses the data package's standardized FMP fields for consistency; segment margins use the sealed issuer-disclosed `Earnings (loss) before income taxes` divided by gross revenue and must not be relabelled operating margin.

Margin evidence, percent	FY2021	FY2022	FY2023	FY2024	FY2025	Interpretation
Consolidated operating margin	16.06	23.87	17.68	17.82	16.35	A 7.8-point cycle range; FY2022 peak did not persist
Oil Sands pretax margin	18.4	25.7	36.7	31.7	27.3	Strong asset economics, but 18.3-point range
E&P pretax margin	60.1	74.4	62.9	31.0	21.0	Severe compression and depletion/mix sensitivity
R&M pretax margin	12.6	15.5	10.9	8.3	9.2	Positive through the period, but crack-driven compression

The strongest evidence is that every segment remained profitable through the observed years and R&M stayed positive even as margins compressed. The counterevidence is more important for the Gideon bar: standardized ROIC was only 8.74%-19.21% and below 12% in four of five years. Margin persistence therefore supports *survivability and asset utility*, not a demonstrated ability to compound capital above 20% through cycles.

4. AI disruption stress test

None of Suncor's major segments is a prompt-to-output workflow that a foundation model can disintermediate. Their value resides in mineral rights, permitted facilities, steel, wells, cokers, pipelines, terminals, tanks, refineries, stations, safety systems, and trusted physical delivery. AI can improve the economics but cannot synthesize a delivered barrel.

Oil Sands is most protected. AI can improve predictive maintenance, ore-body modelling, autonomous haul, steam optimization, energy use, scheduling, anomaly detection, and turnaround planning. Benefits diffuse across the industry through equipment vendors and labour mobility, so AI is more likely to reduce the cost curve for all efficient operators than create a proprietary moat. Cyber and model-control failures add operational risk; human and regulatory accountability remain essential in safety-critical systems.

E&P is the most exposed segment, although still not disintermediated. AI-enhanced reservoir interpretation, drilling, subsea inspection, and maintenance may lower development cost, but peers can buy similar tools. Better global exploration and short-cycle optimization can expand competitive supply and pressure price. The segment's finite reserve base and non-operated interests leave less unique physical optionality than Oil Sands.

R&M is operationally protected but commercially reshaped. AI can optimize crude slate, blending, yields, inventories, logistics, retail pricing, and maintenance. It can also help competitors and traders arbitrage regional spreads faster, potentially shortening temporary location or information advantages. The durable chokepoints are permitted conversion capacity and distribution access; the least durable profit is discretionary trading or local information advantage. AI is thus a productivity tailwind, not a reason to upgrade the moat gate.

5. The 2046 test

Test date: 2046-09-06. A credible 2046 Suncor still produces bitumen and synthetic crude from Alberta, but its mix is more concentrated in the lowest-cost, best-permitted mines and in situ reservoirs. It sells to North American and export refineries that still need dense liquid fuels and hydrocarbon feedstocks. The E&P segment is much smaller after offshore field decline unless tie-backs replace depleted volumes; aging platforms approach retirement. R&M operates fewer or reconfigured gasoline assets, produces proportionally more diesel, jet fuel, asphalt, petrochemical feedstocks, renewable/co-processed fuels, and compliance credits, and uses the Petro-Canada/Petro-Pass network for charging, fleet energy, convenience, and remaining liquid-fuel demand. The company still makes money because its surviving resources have low natural decline and are connected to sunk upgrading, refining, logistics, export, and retail capacity that cannot be cheaply replicated.

That description is specific, but high returns are not assured. The IEA's Stated Policies Scenario has global oil demand peaking around 2030 and then declining, while aviation and petrochemical use continue to grow [W2]. Its 2026 EV outlook estimates about 5 million bbl/d of oil displacement by 2030 under current/stated policies [W1]. The Canada Energy Regulator nevertheless projects oil sands as the majority of Canadian output in all its 2050 scenarios and near 2024 volumes even in lower cases [W7]. This supports asset *relevance*, not price protection.

Directionally, 2046 operating margin is more likely lower and more volatile than today's strong TTM result: gasoline demand is weaker, carbon and reclamation spending consume more of the barrel margin, and marginal global supply sets price. The approximately 20-year calculated reserve life at FY2025 lands almost exactly on the test date, so 2046 economics require reserve conversion, replacement areas, sustained approvals, and reinvestment; existing reserves are not a free perpetual annuity.

Bear 2046. Global road-fuel demand falls faster than refinery closures, creating chronic overcapacity and weak cracks. Lower-cost Middle Eastern, U.S., Brazilian, and other barrels set a price that compresses oil-sands rents. Carbon compliance, methane rules, tailings/water remediation, and reclamation costs rise; a key mine extension or water solution is delayed. E&P declines without adequate tie-backs. High-cost CCUS does not rescue the system: CER's high-cost sensitivity assumes materially dearer capture and shows 2050 oil-sands production 25% below its Canada Net-zero case and 40% below Current Measures [W7]. Suncor survives as a smaller harvest business, but excess returns disappear.

This bear case is materially plausible rather than remote because each mechanism is already observable in demand forecasts, regulatory design, or asset obligations. The fact that CER also shows durable oil-sands volumes prevents a bankruptcy-style conclusion; it does not establish a 20-year high-return moat.

6. Competitive threat inventory

Threat	Mechanism	Segment(s) affected	Earliest observable signal	Plausibility
Global supply outgrows demand	IEA sees capacity growth exceeding demand growth to 2030; lower-cost barrels compress benchmark price and Canadian heavy realizations [W8]	Oil Sands; E&P	Multi-year weak WTI/WCS netbacks despite normal takeaway; curtailed growth capital	High
Road-fuel transition outruns refinery rationalization	EVs and efficiency reduce gasoline/diesel demand before regional capacity exits; imports cap cracks	R&M; indirectly Oil Sands	Three-year decline in same-market product sales and refinery utilization; weak cracks despite reliable operations	Medium-high
Carbon, water, tailings, and reclamation burden escalates	Existing/proposed rules tighten lifecycle carbon and upstream emissions; required abatement or approvals raise cost and constrain output [W3][W4]	Oil Sands; R&M	Compliance cost per barrel rises faster than intensity falls; approvals or CCUS infrastructure slip	High

Cost inflation cuts across all three: Wood Buffalo labour, turnarounds, mining equipment, natural gas, steel, and offshore services can erase scale benefits. The observable defence is not nominal spending discipline but stable inflation-adjusted sustaining capital and unit cost alongside reliable volumes.

7. Pricing power verification

Pricing power is **weak and not verified**. The package shows commodity realizations, royalties, transportation, netbacks, gross margins, and channel volumes; it does not show Suncor-led list-price increases, adoption/churn resilience, multi-year escalators, or minimum commitments that permit price increases independent of benchmarks. Upstream sales are benchmark-linked. Refining captures crack, quality, location, and timing spreads. Retail pricing is transparent and locally competitive.

The best evidence of economic capability is margin capture, not price setting: reliable refineries, optimized channels, and product export can retain more of an available market spread. Likewise, upgrading can improve realization versus raw bitumen. But both are conditional on external price relationships. FY2021-FY2025 R&M FIFO gross margin ranged from CAD 36.40/bbl to CAD 55.85/bbl, while pretax margin compressed from 15.5% in FY2022 to 8.3% in FY2024. That is consistent with cyclical spread capture, not unilateral pricing. No pricing-power premium is awarded.

8. Moat verdict

Moat gate: FAIL. Suncor has a formidable physical position and meaningful cost, reliability, and routing advantages, especially in Oil Sands and integrated R&M. Those assets deter greenfield entry and should remain useful, but the profit pool is governed by commodity prices, crack spreads, utilization, and public policy; customers are not locked in and Suncor cannot set price. Five-year margin and ROIC evidence demonstrates cyclicality rather than stable high-return compounding. Under ER2 calibration, an asset barrier and capacity-cycle advantage do not clear the 20-year compounder bar.

2046 test: FAIL. A specific operating company can be described in 2046, and Oil Sands likely remains the core, but the evidence does not support high returns with sufficient confidence: the current calculated reserve life reaches the test date, E&P likely withers, road-fuel demand declines, and carbon/tailings/reclamation capital burdens rise. The likely survivor is a durable producer and converter, not demonstrably a >20% return compounder.

Upgrade signals: (1) at least five additional years in which through-cycle ROIC remains above 15% and approaches the 20% hurdle without relying on an oil-price spike; (2) inflation-adjusted Oil Sands unit cost and sustaining capital per barrel fall while reliability holds through full turnaround cycles; (3) sanctioned, financeable decarbonization and water/tailings solutions preserve approvals and materially lower compliance exposure; and (4) R&M demonstrates durable non-gasoline margin growth rather than only high cracks.

Further downgrade signals: (1) three-year deterioration in unit cost, availability, and sustaining capital simultaneously; (2) failed or delayed mine-extension, tailings-water, or CCUS infrastructure approvals; (3) refinery utilization and product sales decline together while low-carbon/non-fuel earnings fail to replace lost gasoline margin; or (4) reserve life drops below the remaining years to 2046 without economic replacement.

External context sources

- **[W1]** International Energy Agency, [Global EV Outlook 2026 â€” oil displacement](https://www.iea.org/reports/global-ev-outlook-2026/outlook-for-electric-mobility-chap-9-11), accessed 2026-09-06.
- **[W2]** International Energy Agency, [World Energy Outlook 2025 â€” Stated Policies Scenario](https://www.iea.org/reports/world-energy-outlook-2025/stated-policies-scenario), accessed 2026-09-06.
- **[W3]** Canada Gazette, [proposed Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations](https://gazette.gc.ca/rp-pr/p1/2024/2024-11-09/html/reg1-eng.html), accessed 2026-09-06.
- **[W4]** Environment and Climate Change Canada, [Clean Fuel Regulations compliance](https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-regulations/compliance.html), accessed 2026-09-06.
- **[W5]** Canadian Fuels Association, [Canada's Refining Sector, November 2025](https://www.canadianfuels.ca/wp-content/uploads/2025/12/6934_FUEL_Refineries-Maps-Canada-2025Nov_Eng_final.pdf), accessed 2026-09-06.
- **[W6]** Canadian Natural Resources, [Oil Sands Mining & Upgrading](https://www.cnrl.com/world-class-assets/oil-sands/oilsands-mining-upgrading/), accessed 2026-09-06.
- **[W7]** Canada Energy Regulator, [Canada's Energy Future 2026 â€” scenario results](https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2026/results/index.html), accessed 2026-09-06.
- **[W8]** International Energy Agency, [Oil 2025 â€” executive summary](https://www.iea.org/reports/oil-2025/executive-summary), accessed 2026-09-06.

Appendix B1 - Refining and Marketing

Refining and Marketing â€” Segment Deep Dive

Company: Suncor Energy Inc. **Ticker:** SU.TO **Information date:** 2026-09-06 SGT **TTM anchor:** four non-overlapping quarters ended 2026-06-30 **Forecast horizon:** 2031-06-30, exactly five calendar years after the TTM end **Reporting currency:** CAD; dollars are billions unless stated otherwise **Exact segment profit basis:** `Earnings (loss) before income taxes`

0. Segment boundary and taxonomy note

Refining and Marketing comprises refining, supply, trading, logistics, marketing, the Petro-Canada retail and wholesale channels, and related infrastructure. The reportable label and accounting perimeter were stable through FY2021-FY2025. There is nevertheless one critical operating-comparability boundary: effective January 1, 2026, Suncor rerated refinery nameplate capacity from 466 mbbls/d to 511 mbbls/d. That 9.7% denominator increase was not a physical 45 mbbls/d start-up on January 1. Consequently, FY2025 utilization of 103% on the old denominator and Q2 2026 utilization of 92% on the new denominator cannot be compared as if utilization collapsed by eleven points. All forward utilization in this appendix uses the 511 mbbls/d capacity basis, while historical utilization is reproduced as published and marked pre- or post-rerating. The product-revenue note and segment gross-revenue statement also differ because intersegment sales are eliminated elsewhere; product lines are therefore used to allocate and forecast the segment total, not to redefine the segment perimeter. [data_package Â§1, reporting-structure paragraph; Â§0a, comparability paragraph; Â§4, intersegment-revenue paragraph]

1. What this segment actually is

Refining and Marketing is the downstream conversion and route-to-market arm of Suncor's integrated system. Refineries buy or receive crude and other feedstocks, convert them into gasoline, distillate products such as diesel and jet fuel, and other petroleum products, then place those products through wholesale, commercial, export and retail channels. The segment also earns value from crude and product supply, storage, pipeline and terminal logistics, trading, blending, branded fuel marketing, and convenience retail. The customer base therefore ranges from motorists and convenience-store shoppers to commercial fleets, airlines, industrial buyers, wholesalers and export counterparties.

The pricing model is mostly commodity-linked. Refinery economics begin with the difference between product values and feedstock costs, commonly approximated by crack spreads. Actual capture is then modified by crude quality and location discounts, product yield, refinery complexity, energy and hydrogen costs, planned and unplanned downtime, inventory accounting, logistics constraints, environmental compliance and the channel in which each barrel is sold. The U.S. Energy Information Administration defines a 3:2:1 crack as the value of two barrels of gasoline plus one barrel of distillate less three barrels of crude, divided by three; importantly, it excludes other variable and fixed refinery costs. That makes a crack spread a directional driver, not a substitute for Suncor's disclosed segment profit. [EIA crack-spread explanation](https://www.eia.gov/todayinenergy/includes/crackspread_explain.php)

Suncor's downstream integration matters because the refineries can process internally sourced western Canadian crude, while the supply and logistics network can choose among feedstocks and sales channels. When inland crude is discounted, the refining arm can capture part of the differential that would otherwise depress upstream realization. When export demand or a local shortage raises product values, logistics and marketing can direct barrels toward the strongest netback. Retail adds a more recurring gross-margin layer, customer traffic and final-mile distribution. None of these removes the cyclicality of the refinery spread: integration redistributes and sometimes preserves value across the company, but it does not manufacture consolidated profit twice.

For modeling, gasoline, distillate and other products are the three revenue lines because those are the finest consistent dollar disclosures in the sealed data package. Throughput, utilization, refined-product sales, gross margin per barrel, refinery operating expense per barrel and turnaround cadence are operating drivers underneath those lines. Retail, logistics and trading are not separately disclosed in dollars, so they are treated as margin-capture modifiers rather than invented fourth and fifth revenue lines.

2. Current economics

The TTM ended 2026-06-30 is the forecast anchor. Segment gross revenue was CAD 36.617B, calculated in the verified package as Q3 2025 CAD 8.077B plus Q4 2025 CAD 7.603B plus Q1 2026 CAD 9.126B plus Q2 2026 CAD 11.811B.

Exact-basis `Earnings (loss) before income taxes` was CAD 5.523B, producing a 15.08% margin. The profit anchor is substantially above FY2024's CAD 2.596B and FY2025's CAD 2.822B and should not be annualized as a permanent run rate: Q1-Q2 2026 combined strong product pricing and margin capture with high sales, while refinery profitability has historically moved sharply across the cycle. [data_package Â§3, R&M historical table; Â§5, Refining and Marketing quarterly table; Â§3a, TTM bridge, R&M row]

The FY2025 product-revenue mix provides the latest annual allocation: gasoline CAD 13.208B, distillate CAD 14.886B and other CAD 2.577B, totaling CAD 30.671B of customer product revenue. That product total exceeded FY2025 segment gross revenue of CAD 30.569B by CAD 0.102B because the two notes have different elimination mechanics. The mix was 43.1% gasoline, 48.5% distillate and 8.4% other. This appendix applies those shares to the CAD 36.617B TTM segment-revenue anchor to create explicit analytical starting values of CAD 15.769B, CAD 17.772B and CAD 3.077B. Those allocated TTM product values are not issuer-disclosed product revenue for the TTM and are used only so the product forecasts sum exactly to the segment anchor. [data_package Â§4, R&M product rows and intersegment-revenue paragraph; Â§5, R&M quarterly table]

Operationally, refinery crude processed was 480.3 mbbls/d in FY2025, utilization was 103% on the old 466 mbbls/d denominator, and refined-product sales were 623.3 mbbls/d. Q2 2026 throughput was 470.6 mbbls/d, utilization was 92% on the rerated 511 mbbls/d denominator, and sales were 654.8 mbbls/d. The last-four-quarter arithmetic average from the package is approximately 491 mbbls/d of throughput and 656 mbbls/d of sales; this unweighted approximation is a driver check, not a new historical disclosure. Q2 2026 was also the eighth consecutive quarter above 600 mbbls/d of sales. [data_package Â§0a, longest-clean-KPI table, downstream rows; Â§5, volume table; Â§6, R&M commentary]

FY2025 FIFO gross margin was CAD 37.60/bbl and LIFO gross margin CAD 39.50/bbl, versus CAD 36.40 and CAD 37.00 in FY2024. Q2 2026 rose to CAD 69.65/bbl FIFO and CAD 61.50/bbl LIFO. Refining operating expense was CAD 6.50/bbl in FY2025 and CAD 6.35/bbl in Q2 2026. Gross margin per barrel is broader than a simple crack spread but is still above refinery expense and before all depreciation, marketing, logistics, trading, corporate and tax effects. The TTM segment-profit margin therefore reflects a favorable phase of the cycle, not a stable spread less one expense line. [data_package Â§0a, longest-clean-KPI table, R&M gross-margin and expense rows]

Capital intensity is real even though segment capital is not separately quantified in the package. Refineries require recurring turnarounds, reliability work, environmental compliance and sustaining investment; logistics and retail require terminal, pipeline, storage, station and convenience-site spending. The latest schedule identifies R&M refinery, retail and logistics sustainment plus targeted retail investment but does not provide a clean TTM segment-capital total. `[DATA GAP: the sealed data package does not disclose a full standalone R&M capital-expenditure series or TTM R&M capital total.]` This limitation prevents a segment-level return-on-capital calculation; it does not prevent a pretax-profit forecast. [data_package Â§0a, royalties/transportation/capital and project-inventory discussion]

3. Unit economics

The segment converts three economic layers into `Earnings (loss) before income taxes`. First is the manufacturing layer: crude and other feedstock cost versus the wholesale value of gasoline, distillate and other outputs. A more complex refinery can often turn discounted or heavier crude into a higher-value slate, but value depends on secondary-unit availability, hydrogen, energy and catalyst costs, yield loss and environmental specifications. The economic spread can expand rapidly when products are scarce or crude is discounted, and compress when demand softens, inventories build or too much refining capacity chases the same barrel.

Second is utilization and reliability. Fixed labor, maintenance, insurance, depreciation and site overhead do not fall proportionally when throughput declines, so downtime destroys both volume and per-barrel economics. Conversely, high utilization spreads fixed cost over more barrels. Suncor's five-year reported throughput ranged from 415.5 mbbls/d in FY2021 to 480.3 mbbls/d in FY2025, while utilization ranged from 89% to 103% on the old denominator. The 2026 rerating makes a 95% reported utilization on 511 mbbls/d economically similar to roughly 104% on 466 mbbls/d. In other words, the reset lowers the displayed percentage without lowering the barrel count. Forecasting utilization without freezing the denominator would understate future capability or fabricate growth. [data_package Â§0a, longest-clean-KPI table, downstream throughput and utilization rows]

Third is commercial capture. Refined-product sales exceeded refinery throughput because the marketing system also sells purchased product and uses the broader supply network. In the TTM-quarter set, approximate sales of 656 mbbls/d were roughly 34% above approximate throughput of 491 mbbls/d. The gap is not all high-margin incremental production: purchased barrels carry lower conversion economics and trading can generate either gains or losses. Still, scale in procurement, storage,

terminals, exports and retail can improve the destination, timing and channel value of each barrel. Management's phrase â€œselling through the optimal channelsâ€■ is therefore economically relevant, but it cannot justify counting the same integration benefit in both upstream and downstream forecasts. [data_package Â§5, volume table; Â§6, R&M commentary]

Product mix matters. Distillate demand is more exposed to freight, aviation and global trade than passenger-car gasoline, and distillate is generally more tradable internationally. Gasoline has strong seasonal demand but faces the more direct long-run substitution risk from vehicle efficiency and electrification. â€œOtherâ€■ includes a mix of lower-volume products and marketing revenues whose margin can be less transparent. Increasing diesel yield can raise weighted product value if distillate cracks remain stronger than gasoline cracks, but it is not free: projects require capital and operations must avoid sacrificing overall yield or reliability.

Inventory accounting can create temporal noise. FIFO and LIFO gross margins moved differently in Q2 2026, and neither should be equated mechanically to segment pretax profit. The model therefore uses through-cycle gross-margin bands as an operating sanity check and product-line pretax margins as the actual arithmetic. The base case assumes FIFO gross margin normalizes toward CAD 36/bbl, close to FY2021 and FY2024-FY2025 rather than Q2 2026's CAD 69.65/bbl. Bear uses CAD 25/bbl, reflecting weak cracks and poor capture; bull uses CAD 50/bbl, below the FY2022 CAD 55.85/bbl and far below the extraordinary Q2 2026 level. This preserves cyclicality rather than extrapolating a spike. [data_package Â§0a, longest-clean-KPI table, R&M FIFO and LIFO gross-margin rows]

The principal margin-down mechanisms are: lower gasoline and distillate cracks; narrowing feedstock discounts; unplanned outages; major turnaround overlap; higher natural-gas, hydrogen, catalyst and labor cost; more low-margin purchased-product sales; export freight and congestion; adverse trading positions; environmental-credit costs; and retail price competition. Margin-up mechanisms are: higher secondary-unit availability; stronger distillate yield; wider discounted-feedstock access; longer turnaround intervals without reliability deterioration; better export and retail placement; lower unit operating expense; and capacity discipline elsewhere in North America.

4. Competitive dynamics

Competition occurs at several levels. Canadian integrated peers such as Imperial Oil compete for crude-feedstock advantage, refinery reliability, wholesale volumes and branded retail customers. Independent or less-integrated marketers compete in retail, convenience and wholesale. U.S. refiners such as Marathon, Valero, ExxonMobil, Phillips 66 and others set the marginal economics in connected product markets and compete for export destinations. Irving and other eastern Canadian refiners influence Atlantic supply, while imports can cap regional pricing whenever logistics are unconstrained.

Suncor's scale is meaningful but does not confer price-setting power over globally traded gasoline or distillate. Its power is relative: configuration, feedstock access, location and logistics can create a lower delivered cost or better netback than a less integrated competitor. Canadian petroleum and coal product manufacturing operated at 90.6% capacity in Q4 2025, indicating a generally tight but not fully constrained industry backdrop. Imperial reported 93% utilization in 2025, a useful competitor reference but not directly comparable to Suncor's old-denominator 103%. [Statistics Canada capacity-utilization release](https://www150.statcan.gc.ca/n1/daily-quotidien/260313/dq260313e-eng.pdf) [Imperial Oil 2025 financial statements](https://www.imperialoil.ca/-/media/imperial/files/investor/shareholders/2026/financial-statements-ye-2025-english.pdf)

North American capacity discipline provides some structural support. U.S. operable atmospheric distillation capacity fell by more than 250 mbbls/d, about 1%, during 2025 to 18.2 mmbbls/d at January 1, 2026. Two shutdowns removed about 400 mbbls/d, partly offset by small debottlenecks, and California capacity losses increased regional volatility because pipeline connectivity is limited. This does not guarantee high cracks in western or central Canada, but it lowers the risk that large greenfield additions swamp demand before 2031. [EIA 2026 refinery-capacity update](https://www.eia.gov/todayinenergy/detail.php?id=67807)

Demand and mix are less favorable for gasoline. The Canada Energy Regulator's 2026 outlook describes relatively flat total refined-product use in Ontario and Quebec, steadily declining gasoline demand, gradually rising diesel demand and slowly recovering jet-fuel demand. In 2024 the region imported 62 mbbls/d of gasoline but exported 50 mbbls/d of diesel, highlighting different regional balances. That context supports management's preference for diesel over gasoline, but it also shows why logistics and export access are essential: domestic gasoline growth is not a plausible five-year thesis. [CER Canadaâ€™s Energy Future 2026](https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2026/analysis-energy-security-and-trade-diversification/)

Canadian output remains concentrated in the two key transport fuels. Statistics Canada reported that finished motor gasoline was 37.9% and distillate fuel oil 36.1% of national refined-petroleum production in 2025. Suncor's FY2025 revenue mix was

more distillate-heavy than that physical national production mix, though revenue shares and volume shares are not interchangeable. [Statistics Canada 2025 refined-petroleum review](https://www.statcan.gc.ca/o1/en/plus/9131-another-record-year-production-refined-petroleum-2025)

Environmental regulation is both a cost and an entry barrier. Canada's Clean Fuel Regulations require suppliers of gasoline and diesel to reduce lifecycle carbon intensity, with the requirement reaching 14 gCO2e/MJ in 2030, and create a credit market for compliance. Large incumbents may have more routes to generate, buy or optimize credits, but they also have larger absolute obligations and capital needs. Compliance can therefore reinforce scale advantages without becoming a pure windfall. [Government of Canada Clean Fuel Regulations](https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/about.html)

Pricing power should thus be described as conditional, not absolute. Retail brand and convenience can retain customers; logistics can improve delivered economics; refinery complexity can widen the choice of feedstocks and products. Yet customers can switch stations, wholesale buyers compare commodity prices, and export barrels compete globally. The segment has execution-based margin advantage, not the kind of contractual or proprietary price escalation seen in a software monopoly.

5. Moat at the segment level

The strongest moat element is the integrated physical system. Refineries, pipelines, terminals, storage, supply operations and retail channels form a network that would be costly, slow and regulatorily difficult to reproduce. The assets' value is greatest as a coordinated system: a refinery without reliable feedstock or product takeaway is less advantaged, while a retail network without supply scale is more exposed to wholesale procurement. Suncor can move value across this chain, choosing feedstock and channel combinations that a single-asset competitor cannot always match.

The second moat element is feedstock flexibility and location. Access to western Canadian crude can offer a cost advantage when inland barrels trade below seaborne alternatives. Complexity and secondary-unit reliability can convert that advantage into valuable products. The benefit is cyclical because pipeline expansions or outages can narrow or widen discounts, and because an integrated company's upstream segment experiences the opposite side of some differentials. This appendix credits downstream capture through its profit margins only. It does not add a separate â€œintegration revenueâ€■ line, and it instructs synthesis not to add the same benefit again in Oil Sands.

Third is operating capability. Multi-year turnaround planning, reliable secondary units, product-yield optimization, trading controls and retail execution are learned processes. Management's plan to move toward five-year turnaround intervals can increase availability, but only if equipment integrity supports it. A longer interval is not itself a moat; superior maintenance that produces both longer intervals and fewer unplanned outages would be. The risk is asymmetric: one major outage can erase several years of incremental efficiency.

Fourth is channel optionality. Management cited a sharp increase in export cargoes and consistently high sales volumes. The ability to choose wholesale, export, commercial and retail channels should improve margin capture and resilience when one local market is weak. However, logistics assets do not eliminate export freight, destination competition or trade policy. Retail offers a modest recurring-margin buffer but is exposed to fuel-demand erosion and convenience competition. [data_package Â§6, R&M concluding paragraph]

The moat is therefore moderate and cycle-dependent. It plausibly protects relative margin and asset utilization over five to ten years, but it does not protect the absolute crack spread. On a 20-year view, declining gasoline demand and rising carbon-compliance burdens reduce the durability of the traditional fuel franchise. The segment can defend itself by shifting yield toward diesel and jet, raising retail non-fuel value, improving logistics and pursuing compliant lower-carbon fuels, but the data package does not provide enough segment economics to award credit for a large new low-carbon profit pool. `[DATA GAP: no separately disclosed revenue or profit for retail, logistics, trading, export channels or lower-carbon fuels is available in the sealed package.]`

6. Historical growth rates

The table reproduces the finest disclosed R&M dollar series from the verified data package. â€œThree-year historical CAGRâ€■ follows the three fiscal observations FY2023-FY2025 and therefore compounds across two year-to-year intervals. Product revenue is customer revenue from the product note; segment gross revenue is the reportable-segment line. The product total does not exactly equal segment gross revenue because of eliminations and presentation.

Product / sub-segment	FY2023 revenue	FY2024 revenue	FY2025 revenue	Three-year historical CAGR	Most recent YoY	Data package cite
Refining and Marketing segment gross revenue	CAD 30.959B [data_package Â§3, R&M gross-revenue row]	CAD 31.266B [data_package Â§3, R&M gross-revenue row]	CAD 30.569B [data_package Â§3, R&M gross-revenue row]	(0.63)% [calculated from same row]	(2.23)% [data_package Â§3, R&M YoY row]	data_package Â§3, R&M table, gross revenue and YoY rows
Gasoline customer revenue	CAD 13.106B [data_package Â§4, R&M Gasoline row]	CAD 13.357B [data_package Â§4, R&M Gasoline row]	CAD 13.208B [data_package Â§4, R&M Gasoline row]	0.39% [calculated from same row]	(1.12)% [calculated from same row]	data_package Â§4, R&M Gasoline row
Distillate customer revenue	CAD 15.283B [data_package Â§4, R&M Distillate row]	CAD 15.181B [data_package Â§4, R&M Distillate row]	CAD 14.886B [data_package Â§4, R&M Distillate row]	(1.31)% [calculated from same row]	(1.94)% [calculated from same row]	data_package Â§4, R&M Distillate row
Other customer revenue	CAD 2.679B [data_package Â§4, R&M Other row]	CAD 2.803B [data_package Â§4, R&M Other row]	CAD 2.577B [data_package Â§4, R&M Other row]	(1.92)% [calculated from same row]	(8.06)% [calculated from same row]	data_package Â§4, R&M Other row

Arithmetic checks pass. CAD 31.266B Ã- (1 âˆ’ 2.23%) = CAD 30.569B for the segment; CAD 13.357B Ã- (1 âˆ’ 1.12%) = CAD 13.208B for gasoline; CAD 15.181B Ã- (1 âˆ’ 1.94%) = CAD 14.886B for distillate; and CAD 2.803B Ã- (1 âˆ’ 8.06%) = CAD 2.577B for other, all within rounding and well inside the 2% tolerance. No product dollars were back-solved. [data_package Â§4, no-growth-only-product paragraph]

The stable dollar history masks operational growth. FY2021-FY2025 throughput increased from 415.5 to 480.3 mbbls/d, and refined-product sales increased from 528.4 to 623.3 mbbls/d, while commodity prices and cracks moved in the opposite direction over parts of the period. Revenue CAGR is thus a poor standalone measure of physical progress. The forward model combines muted-to-negative gasoline revenue growth with positive distillate and sales-volume assumptions, rather than applying one uniform segment CAGR. [data_package Â§0a, longest-clean-KPI table, downstream throughput and sales rows]

7. Management guidance

All guidance below is quoted only from the verified data package. None is re-fetched or expanded from a transcript.

- **D-TR-Q3-25, Q3 FY2025 call dated 2025-11-05:** Dave Oldreive said management was **â€œplanning on a five-year interval going forward.â€■** The reference is to turnaround cadence. The base case credits higher through-cycle availability but retains a maintenance allowance; the bull case captures a cleaner execution outcome, while bear assumes the interval extension contributes to reliability problems or cannot be sustained. [data_package Â§6, R&M bullet 1]
- **D-TR-Q4-25, Q4 FY2025 call dated 2026-02-04:** Oldreive described **â€œselling through the optimal channels.â€■** This supports the role of exports, logistics and retail in margin capture, but it is not a quantified revenue or margin guide. The base case treats it as partial offset to weakening gasoline mix rather than a standalone growth line. [data_package Â§6, R&M bullet 2]
- **D-TR-Q1-26, Q1 FY2026 call dated 2026-05-06:** Oldreive described **â€œa 16,000 barrels a day diesel yield increase.â€■** This is the clearest product-mix anchor. Base assumes 12 mbbls/d of sustained terminal benefit after allowing for ramp and maintenance; bull assumes the full 16 mbbls/d; bear assumes only 5 mbbls/d is sustainably realized. [data_package Â§6, R&M bullet 3]
- **D-TR-Q2-26, Q2 FY2026 call dated 2026-08-05:** Oldreive said the business would **â€œcontinue to grow diesel production preferentially over gasoline.â€■** This direction is consistent with CER's demand outlook and drives a rising distillate revenue share in all cases except where the bear's weak cracks partly offset volume. [data_package Â§6, R&M bullet 4]

Additional verified context is that management emphasized integration, logistics, export optionality, retail-channel growth and high secondary-unit utilization. Q2 2026 sales reached 654.8 mbbls/d, the eighth consecutive quarter above 600 mbbls/d, and management said 56 cargoes were exported in H1 2026 compared with 58 in all FY2025. These observations support channel depth but do not specify 2031 volumes or profitability. [data_package Â§6, R&M concluding paragraph]

`[DATA GAP: management did not provide a quantified five-year R&M revenue, pretax-profit, utilization, sales-volume, retail-profit or normalized-margin target in the sealed package.]`

8. Forward growth assumptions

The forecast starts from CAD 36.617B of TTM segment gross revenue and allocates it using FY2025 disclosed product-revenue shares: gasoline CAD 15.769B, distillate CAD 17.772B and other CAD 3.077B. The allocation is analytical and constrained to the segment total. Each product CAGR combines sales volume, price normalization and mix; it is not a pure demand forecast. The period is exactly five years from 2026-06-30 to 2031-06-30.

Base case

Product	Three-year historical CAGR	Latest YoY	Management FY+1 guide	Base CAGR TTM to TTM+5y	Justification
Gasoline	0.39%	(1.12)%	Prefer diesel over gasoline; no numeric gasoline guide	(2.0)%	Canadian gasoline demand declines and TTM pricing normalizes; retail and channel capture soften but do not reverse the decline.
Distillate	(1.31)%	(1.94)%	16 mbbls/d diesel-yield project; preferential diesel growth	1.5%	Sustained 12 mbbls/d yield benefit and export optionality outweigh modest price normalization, consistent with firmer diesel than gasoline demand.
Other	(1.92)%	(8.06)%	Retail/logistics growth qualitative only	0.5%	Retail and logistics activity grows slowly, but no undisclosed low-carbon or trading profit pool is invented.

The base case ends at gasoline CAD 14.254B, distillate CAD 19.145B and other CAD 3.154B. Total revenue is CAD 36.553B, essentially flat in nominal terms because the distillate shift and modest sales growth offset gasoline erosion and normalization from an elevated TTM revenue level. This is not the same as assuming operations stagnate: refined-product sales rise to 675 mbbls/d, while product value per unit and mix absorb the difference.

Bear case

Product	Three-year historical CAGR	Latest YoY	Management FY+1 guide	Bear CAGR TTM to TTM+5y	Justification
Gasoline	0.39%	(1.12)%	Prefer diesel; no numeric gasoline guide	(5.0)%	Faster substitution, weak cracks and retail competition overwhelm channel optimization.
Distillate	(1.31)%	(1.94)%	16 mbbls/d project aspiration	(2.0)%	Only 5 mbbls/d of yield benefit persists, export margins weaken and freight demand underperforms.
Other	(1.92)%	(8.06)%	No numeric guide	(2.5)%	Lower trading/wholesale activity and compliance cost offset retail resilience.

The bear case ends at gasoline CAD 12.201B, distillate CAD 16.064B and other CAD 2.711B, or CAD 30.977B total. Sales fall to 600 mbbls/d, throughput falls to 460 mbbls/d and utilization falls to 90.0% on 511 mbbls/d. The decline is non-uniform: gasoline is the principal structural loser, while distillate is cushioned by yield investment but still falls under weak macro and crack-spread conditions.

Bull case

Product	Three-year historical CAGR	Latest YoY	Management FY+1 guide	Bull CAGR TTM to TTM+5y	Justification
Gasoline	0.39%	(1.12)%	No numeric gasoline guide	0.5%	North American capacity closures and superior channel placement offset secular volume decline without assuming strong domestic demand.
Distillate	(1.31)%	(1.94)%	Full 16 mbbls/d diesel-yield increase	4.0%	Full yield delivery, durable diesel cracks, high secondary-unit availability and export growth compound together.
Other	(1.92)%	(8.06)%	Retail/logistics growth qualitative only	2.0%	Retail, logistics and specialty products expand, with no separate acquisition assumption.

The bull case ends at gasoline CAD 16.167B, distillate CAD 21.622B and other CAD 3.397B, or CAD 41.186B total. Sales reach 720 mbbls/d, throughput reaches 505 mbbls/d and utilization reaches 98.8% on 511 mbbls/d. Gasoline does not become the growth engine; the upside comes primarily from distillate, reliability, exports and capacity discipline.

Operational driver and capacity-rerating check

Driver	TTM / latest anchor	Bear 2031-06-30	Base 2031-06-30	Bull 2031-06-30	Interpretation
Nameplate capacity, mbbls/d	511 post-rerating	511	511	511	Rerating is already effective; no new physical capacity is assumed.
Crude throughput, mbbls/d	Approx. 491 TTM	460	497	505	Reflects downtime and reliability; all terminal values remain at or below rerated capacity.
Utilization on 511 basis	Approx. 96.1% TTM	90.0%	97.3%	98.8%	Comparable denominator across cases; old-basis 103% is not used.
Refined-product sales, mbbls/d	Approx. 656 TTM	600	675	720	Sales can exceed throughput through supply, purchases and marketing.
Sustained diesel-yield gain, mbbls/d	Project in ramp	5	12	16	Case-specific realization of management's disclosed project.
Turnaround interval	Five-year intent	Interval fails or outage offsets benefit	Five-year planning with normal maintenance	Five-year interval executes cleanly	No case assumes zero maintenance.
FIFO gross margin, CAD/bbl	Q2 2026 69.65; FY2025 37.60	25	36	50	Through-cycle driver band, not a direct profit identity.
Refining operating expense, CAD/bbl	Q2 2026 6.35; FY2025 6.50	7.50	6.75	6.25	Bear inflation/outages; base normal; bull scale and reliability.

The table prevents the capacity-rerating trap. If the old 466 mbbls/d denominator were used, base throughput of 497 would misleadingly imply 106.7% utilization; on the valid 511 basis it is 97.3%. No revenue is credited merely because the nameplate label increased. Revenue grows only through product-level volume, price and mix assumptions, and no separate 45 mbbls/d â€œcapacity additionâ€■ appears anywhere.

The total-revenue cadence is also deliberately non-linear by product even though constant product CAGRs summarize the five-year endpoint. Aggregate bear revenue steps down from CAD 36.617B to approximately CAD 35.396B, CAD 34.224B, CAD 33.098B, CAD 32.016B and CAD 30.977B. Base totals are CAD 36.584B, CAD 36.561B, CAD 36.548B, CAD 36.546B and CAD 36.553B. Bull totals rise to CAD 37.468B, CAD 38.350B, CAD 39.262B, CAD 40.207B and CAD 41.186B. This makes the normalization path visible and avoids treating Q2 2026's 62.3% segment-revenue growth as a sustainable compounding rate.

9. Forward `Earnings (loss) before income taxes` margin assumptions

The forecast metric is exactly `Earnings (loss) before income taxes`. It is not operating income, EBITDA, adjusted funds flow or refinery gross margin. Corporate and Eliminations, financing and tax remain outside this segment forecast and are left to synthesis. The TTM exact-basis margin is 15.08% on CAD 5.523B of profit and CAD 36.617B of revenue. [data_package Â§3a, TTM bridge; Â§5, R&M quarterly table]

Case	Product	2031-06-30 revenue	`Earnings (loss) before income taxes` margin	2031-06-30 product profit	Mechanism versus TTM
Bear	Gasoline	CAD 12.201B	5.0%	CAD 0.610B	Weak gasoline cracks, lower utilization, retail competition and compliance cost.
Bear	Distillate	CAD 16.064B	8.0%	CAD 1.285B	Some yield benefit survives, but export margins, freight demand and capture weaken.
Bear	Other	CAD 2.711B	4.0%	CAD 0.108B	Lower trading and wholesale activity; no speculative low-carbon uplift.
Base	Gasoline	CAD 14.254B	8.5%	CAD 1.212B	Structural demand erosion partly offset by retail and logistics.

Case	Product	2031-06-30 revenue	Earnings (loss) before income taxes margin	2031-06-30 product profit	Mechanism versus TTM
Base	Distillate	CAD 19.145B	12.0%	CAD 2.297B	Diesel-yield optimization and export channels support better mix.
Base	Other	CAD 3.154B	7.0%	CAD 0.221B	Stable retail/logistics contribution with normal compliance burden.
Bull	Gasoline	CAD 16.167B	11.5%	CAD 1.859B	Capacity closures and tight regional supply sustain cracks and channel capture.
Bull	Distillate	CAD 21.622B	16.5%	CAD 3.568B	Full yield gain, high availability, strong global diesel pricing and exports.
Bull	Other	CAD 3.397B	10.0%	CAD 0.340B	Strong retail/logistics execution without a new business-line assumption.

The bear blended margin is 6.47%, 861 bps below the TTM margin. The mechanisms are simultaneous but not duplicated: FIFO gross margin falls to CAD 25/bbl; throughput and sales decline; expense rises to CAD 7.50/bbl; and channel mix weakens. Product margins embed those effects once. There is no additional segment-level outage charge or integration haircut after the product profits are summed.

The base blended margin is 10.20%, 488 bps below TTM and close to the middle of the FY2021-FY2025 exact-margin range of 8.3%-15.5%. FIFO gross margin normalizes to CAD 36/bbl, broadly consistent with FY2021, FY2024 and FY2025. Expense rises modestly to CAD 6.75/bbl in nominal terms, while 97.3% utilization, diesel mix and logistics offset part of the cycle normalization. This is a meaningful drop, not a token haircut to the current peak.

The bull blended margin is 14.00%, 108 bps below TTM. It assumes CAD 50/bbl FIFO gross margin, high but below FY2022's CAD 55.85/bbl and substantially below Q2 2026's CAD 69.65/bbl. Throughput reaches 505 mbbls/d, utilization 98.8%, sales 720 mbbls/d and expense CAD 6.25/bbl. The case requires multiple favorable conditions but still does not freeze the unusually high TTM margin.

The product margins are analytical allocations because the issuer does not disclose gasoline, distillate and other `Earnings (loss) before income taxes`. Their sole purpose is to make mix and profit arithmetic transparent. The segment profit totals, not the individual allocations, should be used in statutory synthesis. `[DATA GAP: product-level exact-basis profit and product-level refinery gross margin are not separately disclosed.]`

10. Segment rollup

Case	Gasoline revenue	Distillate revenue	Other revenue	Segment revenue	Blended Earnings (loss) before income taxes margin	Segment Earnings (loss) before income taxes	Probability
Bear	CAD 12.201B	CAD 16.064B	CAD 2.711B	CAD 30.977B	6.47%	CAD 2.004B	30%
Base	CAD 14.254B	CAD 19.145B	CAD 3.154B	CAD 36.553B	10.20%	CAD 3.730B	50%
Bull	CAD 16.167B	CAD 21.622B	CAD 3.397B	CAD 41.186B	14.00%	CAD 5.767B	20%

Every row ties within rounding. Bear revenue sums to CAD 30.976B before display rounding and product profit to CAD 2.004B; base revenue sums to CAD 36.553B and profit to CAD 3.730B; bull revenue sums to CAD 41.186B and profit to CAD 5.767B. Blended margins equal summed product profit divided by summed product revenue. Differences of CAD 0.001B reflect three-decimal presentation only and are far below the 1% reconciliation tolerance.

The probability-weighted segment output is CAD 35.807B of revenue and CAD 3.620B of `Earnings (loss) before income taxes`, but this is only a diagnostic weighted value, not a fourth scenario. Probabilities are asymmetric at 30% bear, 50% base and 20% bull because the TTM starts from an elevated margin environment, gasoline faces structural pressure, and execution risk from turnarounds and asset reliability is negatively skewed. The bull retains a meaningful 20% weight because North American capacity closures, distillate tightness and Suncor's diesel/logistics strategy can sustain above-normal capture.

No Oil Sands integration benefit is added to revenue or profit outside the case margins. If the Oil Sands appendix credits improved internal placement or differential capture, synthesis must treat that as the upstream side of the same integrated

system and avoid adding a consolidated â€œsynergyâ€■ line. The R&M profit cases already embody feedstock, logistics and channel advantages once.

11. Key risks and wildcards

- **Bear â€” crack-spread normalization or collapse.** Crack spreads can move far faster than demand or capacity. The EIA notes they are affected by regional specifications, maintenance, outages, transport constraints, seasonality and inventories. A move from Q2 2026 conditions to weak gasoline and distillate cracks would compress profit even if throughput stayed high. [EIA product-price and crack-spread drivers](https://www.eia.gov/finance/markets/products/prices.php)
- **Bear â€” rerating illusion.** Investors could misread lower utilization on the 511 mbbls/d denominator as deteriorating operations or, conversely, count the 45 mbbls/d rerating as real new capacity. The model avoids both, but reported comparisons may remain noisy until a full post-rerating history exists.
- **Bear â€” turnaround interval overreach.** Extending planned intervals to five years creates value only if equipment integrity supports it. Deferred work that raises unplanned downtime would destroy more margin than the planned-day savings create.
- **Bear â€” gasoline demand and regulation.** Vehicle efficiency, electrification and carbon-intensity rules pressure gasoline volume and raise compliance obligations. Retail convenience and channel optimization can slow, not eliminate, that trend.
- **Bear â€” operating-cost inflation.** Labor, contractor, catalyst, natural-gas, hydrogen and maintenance costs can push refinery expense above the CAD 6.50/bbl FY2025 level, particularly during outages or major work.
- **Bear/Base â€” export and logistics execution.** Export optionality is valuable only when destination netbacks exceed freight and handling. Port congestion, trade restrictions, weak overseas demand or poor trading decisions can turn apparent optionality into low-margin volume.
- **Base/Bull â€” diesel-yield delivery.** The 16 mbbls/d disclosed project is the most tangible product-mix catalyst. Under-delivery would reduce distillate growth and margin; successful sustained delivery supports base and full delivery is required for bull.
- **Bull â€” capacity closures.** U.S. closures can tighten regional product balances and improve volatility/capture, especially where pipelines are constrained. The wildcard is whether demand destruction and imports offset the lost capacity before 2031.
- **Bull â€” channel and retail productivity.** Higher sales without comparable throughput can add commercial value if procurement and placement are disciplined. If purchased-product sales are thin-margin, headline volume growth will overstate economic progress.
- **All cases â€” inventory and trading volatility.** FIFO/LIFO differences and trading results can shift quarterly reported economics. A single quarter's gross margin should never be treated as the durable profit basis.
- **All cases â€” policy and clean-fuel credit economics.** Credits may reward advantaged compliance investments or impose material purchase costs. The sealed package does not quantify a segment credit position, so no case embeds a discrete credit windfall.
- **All cases â€” integrated-company double counting.** Wider western Canadian crude discounts can benefit refinery feedstock economics while hurting upstream realization. Adding both a downstream benefit and an upstream benefit from the same spread would overstate consolidated profit.

Summary

Case	Segment TTM+5y revenue	Exact profit metric	Segment TTM+5y profit margin	Segment TTM+5y profit	Probability
Bear	CAD 30.977B	`Earnings (loss) before income taxes`	6.47%	CAD 2.004B	30%
Base	CAD 36.553B	`Earnings (loss) before income taxes`	10.20%	CAD 3.730B	50%
Bull	CAD 41.186B	`Earnings (loss) before income taxes`	14.00%	CAD 5.767B	20%

The base case is a normalization thesis, not a growth thesis: almost flat nominal revenue, modest physical sales growth, higher distillate mix and a materially lower pretax margin than TTM. The bull requires the diesel-yield project, high availability, exports and capacity discipline to work together; the bear combines structurally weak gasoline with poor cracks and reliability. Across all cases, the 2026 capacity rerating is treated as a denominator change, the exact issuer profit metric is preserved, and integration is counted once.

Appendix B2 - Oil Sands

Oil Sands â€” Segment Deep Dive

Company: Suncor Energy Inc. **Ticker:** SU.TO **Forecast anchor:** TTM ended 2026-06-30 **Horizon:** 2031-06-30, exactly five calendar years **Reporting currency:** CAD; dollar amounts are billions unless stated otherwise **Exact modeled segment profit basis: Earnings (loss) before income taxes**

This appendix models only the Oil Sands reportable segment. Corporate and Eliminations, financing expense, tax, Exploration and Production, and Refining and Marketing are outside its financial perimeter and remain for the synthesis stage. Suncor historical figures, growth rates, management quotations, and accounting classifications below come only from the DR-cleared `data_package.md` and sealed `statutory_bridge.json`. External sources are used only for industry structure, competing assets, pipeline conditions, and regulatory context. The current share price is deliberately not used because valuation and trade work are outside this stage.

0. Segment boundary and taxonomy note

Oil Sands comprises Base Plant mining and upgrading, In Situ, Fort Hills, and Syncrude. The reportable-segment label is stable across FY2021-FY2025, so there is no taxonomy restatement boundary within the five-year history. Comparability nevertheless has two operating-method boundaries: Suncor increased its Fort Hills ownership in 2023, changing the economic perimeter without changing the segment label; and beginning Q1 2026 it changed price realizations to exclude transportation and restated the comparative quarter. The annual realization series through FY2025 must therefore not be spliced mechanically to H1 2026. The 2022 cash-cost presentation change aggregated inventory changes and internal transfers, with comparative periods updated and no change to total cash cost or per-barrel amounts. [data_package Â§1, lines 74-86; Â§0a, lines 24-46]

1. What this segment actually is

Suncorâ€™s Oil Sands business is a very long-life manufacturing system built around a fixed hydrocarbon resource. Mining assets excavate ore, separate bitumen from sand, and either upgrade it into synthetic crude oil and diesel or sell non-upgraded bitumen after blending it with diluent. In-situ assets use steam-assisted recovery to mobilize bitumen underground, avoiding a surface mine but requiring steam generation, wells, gathering systems, water treatment, and continuous pad replacement. Base Plant and Syncrude combine mining and upgrading; Fort Hills is a mining operation whose production is sold as bitumen; and the In Situ portfolio supplies non-upgraded bitumen and feedstock into the integrated network.

The customers are refiners and crude-oil marketers, including Suncorâ€™s own downstream network. Pricing is commodity-linked rather than contractual software-style recurring revenue. Upgraded synthetic crude usually realizes closer to light-crude benchmarks because the upgrader removes much of the density and sulphur discount. Non-upgraded bitumen is more directly exposed to Western Canadian Select and similar heavy-crude differentials, plus diluent and transportation costs. The customer-revenue note reports synthetic crude oil and diesel separately from bitumen, while the reportable-segment statement includes intersegment economics and eliminates them centrally. This distinction matters: FY2025 Oil Sands customer revenue of C$27.324B did not equal reportable-segment gross revenue of C$19.298B. Product-note mix therefore provides exposure context but cannot safely allocate the segment anchor, and product-note dollars cannot be added to segment revenue as if they were a second revenue pool. [data_package Â§4, lines 186-206]

The go-to-market model is a combination of physical logistics and internal integration. Pipeline commitments, storage, blending, upgrading, and access to Suncor refineries broaden the set of outlets for each barrel. That network can reduce forced selling in a congested basin, but it does not eliminate exposure to global crude prices or regional differentials. In this appendix integration is treated as resilience and realization support inside the Oil Sands assumptions. No refinery crack spread, retail margin, or downstream trading profit is added to Oil Sands; those belong to Refining and Marketing and would be double counted here.

Oil Sands differs from conventional upstream in its decline and capital profile. An operating mine, upgrader, or thermal facility can maintain a comparatively flat production plateau for many years, but only through mine-face advancement, new in-situ well pads, turnarounds, tailings handling, water and steam infrastructure, and replacement of large mechanical systems. The result is lower geological decline than many shale assets but higher fixed cost, higher sustaining capital, and greater exposure to planned and unplanned downtime. This makes utilization and turnaround cadence as important as nominal reserve size.

2. Current economics

The sealed TTM anchor is C$20.888B of gross segment revenue, calculated in the data package from the four non-overlapping quarters Q3 2025 through Q2 2026. Oil Sands generated C$6.965B of **Earnings (loss) before income taxes**, a 33.34% margin on that exact basis. This is not operating income, EBITDA, funds flow, or netback. The statutory bridge records it as one of three issuer-disclosed segment-profit lines; Corporate and Eliminations of negative C$1.509B, the financing reclassification, financing expense, and tax all sit outside this segment. [data_package Â§3a, lines 158-184; statutory_bridge.json TTM period]

The TTM contained pronounced quarterly volatility. Oil Sands gross revenue moved from C$4.822B in Q3 2025 to C$4.680B in Q4, C$5.335B in Q1 2026, and C$6.051B in Q2. The exact pretax margin moved from 34.0% to 23.9%, 28.4%, and 44.5%. Q2â€™s strong price realization was accompanied by weak physical output: Oil Sands production was 690.1 Mbbls/d versus FY2025â€™s 799.4 Mbbls/d annual average, as major maintenance and extraordinary wet weather reduced upstream production, with the weather effect estimated at 50-60 Mbbls/d. That juxtaposition is a warning against annualizing either Q2â€™s margin or its production trough. [data_package Â§5, lines 208-242]

FY2025 provides the cleanest product and full-year operating picture. Synthetic crude oil and diesel customer revenue was C$17.803B and bitumen customer revenue was C$9.521B. Their 65.15% / 34.85% customer-revenue mix is retained only as historical context: it is not a TTM product split, does not allocate the C$20.888B segment anchor, and does not drive forecast arithmetic. The forecast instead controls directly from the DR-cleared total segment TTM revenue and profit because the customer-revenue product note and reportable-segment statement have different perimeters. [data_package Â§4, rows at lines 190-200]

Physical output has grown even while prices cycled. Total Oil Sands production rose from 644.2 Mbbls/d in FY2021 to 799.4 Mbbls/d in FY2025, a 5.55% four-year CAGR. Upgraded realization fell from C$118.88/bbl in FY2022 to C$87.79 in FY2025, and non-upgraded bitumen realization fell from C$84.63 to C$62.02 over the same commodity-cycle comparison. In FY2025 the cash operating cost was C$26.55/bbl for Oil Sands operations, C$33.10 for Fort Hills, and C$33.70 for Syncrude. Q2 2026 maintenance and weather pushed those measures to C$32.70, C$44.50, and C$40.15. The base case assumes these Q2 spikes largely reverse, but not that every asset converges to the lowest peer cost. [data_package Â§0a, lines 24-46]

Capital intensity is substantial and cannot be inferred from the segment pretax margin alone. At the company level, asset sustainment and maintenance capital was C$3.162B in FY2025 and economic investment capital C$2.496B; total capital including capitalized interest was C$5.856B. The package does not provide a complete TTM Oil Sands-only split, so the scenario capital amounts in this appendix are explicit analytical estimates and do not reduce **Earnings (loss) before income taxes** directly. Depreciation related to that capital is captured through the segment margin path; actual cash returns will depend on synthesis-level capital and working-capital modeling. [data_package Â§0a, lines 62-72]

3. Unit economics

The first-order equation is volume multiplied by net realized price, less royalties, transportation and distribution, operating cost, depreciation and depletion, and segment-level overhead. Upgraded barrels generally earn a higher realization but require mining, extraction, and energy-intensive upgrading. Non-upgraded in-situ barrels avoid the upgrader but incur steam, diluent, and heavy-oil differential exposure. Fort Hills produces mined bitumen, so it combines mining cost with a non-upgraded price. Syncrude has an upgrader and historically higher maintenance complexity. This is why the upgraded versus bitumen product split alone cannot be read as a simple high-margin versus low-margin split.

Volume creates strong operating leverage because mines, extraction plants, upgraders, and thermal central-processing facilities carry large fixed costs. When throughput falls for a turnaround, weather, ore-quality problem, fire, or equipment failure, the numerator of cash cost remains sticky while the denominator shrinks. The Q2 2026 cost spike is a current example. Conversely, extending Firebag turnaround cycles and filling spare Fort Hills capacity can improve per-barrel cost without requiring greenfield-scale investment. Managementâ€™s phrase â€œhigher volumes, lower unit costsâ€■ expresses this denominator effect, but the model assumes only partial delivery because the historical record still contains material volatility. [data_package Â§6, Oil Sands row at line 250]

Price has two layers. The global layer is WTI/Brent and foreign exchange; the regional layer is the light-heavy differential and each productâ€™s quality and location adjustment. The Canada Energy Regulator reported that the WTI-WCS differential averaged about US$12/bbl from June 2024 to July 2025 after Trans Mountain Expansion began service, compared with about US$18.70 before startup. That is a structural improvement in egress, not a permanent guarantee. The Enbridge Mainline ran at 95.2% utilization in 2025 and remained apportioned in most months on some heavy lines, while TMX averaged 85%

utilization. Basin growth can absorb spare capacity, and outages can reopen the discount. [B-EXT-CER-DIFF; B-EXT-CER-PIPE; archived source register]

Royalties are progressive and therefore dampen both upside and downside. The data package reports company-wide royalties of C$3.469B in FY2025 and C$2.454B in H1 2026, but not a clean TTM Oil Sands effective rate on a basis identical to segment revenue. The scenarios therefore use explicit incremental royalty pass-through assumptions rather than fabricating a historical segment rate. Base assumes roughly 18% of a marginal realization gain is absorbed by royalties; bear assumes 12% because lower prices reduce the rate; bull assumes 24% because mature projects and stronger prices move further up the royalty curve.

Cash operating cost is the largest controllable driver. Base assumes normalized costs around C$27/bbl at Oil Sands operations, C$31 at Fort Hills, and C$32 at Syncrude by the horizon. That requires productivity and reliability improvement but does not assume Suncor becomes the lowest-cost operator. Bear assumes C$38, C$45, and C$44 as inflation, ore, maintenance, and downtime overwhelm volume leverage. Bull assumes C$23, C$27, and C$28 as automation, turnaround extension, and steady high utilization spread fixed cost over more barrels. Imperialâ€™s 2025 disclosures show Kearl at roughly 280 Mbbls/d gross, while Canadian Natural links debottlenecking and turnaround changes to high utilization and low mining/upgrading cost. Those peers demonstrate the opportunity but also raise the competitive bar. [B-EXT-IMO; B-EXT-CNQ; archived source register]

Sustaining investment is economically unavoidable. Mine extensions, tailings development, equipment replacement, upgrader maintenance, in-situ pads, steam infrastructure, and reclamation all compete for capital. Base assumes C$4.0B annual Oil Sands sustaining plus growth capital near the horizon, bear C$4.4B despite lower output because remediation and maintenance do not flex fully, and bull C$4.7B to support higher capacity and environmental works. These are capital-intensity diagnostics, not profit deductions and not issuer guidance. [DATA GAP: the data package does not disclose a complete, basis-consistent TTM Oil Sands-only split between sustaining and growth capital.]

4. Competitive dynamics

The direct Canadian competitors are other long-life oil-sands mining/upgrading and thermal operators, principally Canadian Natural, Cenovus, and Imperial Oil. Their assets compete for pipeline capacity, contractors, skilled labour, natural gas, diluent, and refinery demand. At the same time, industry coordination on takeaway and shared environmental technology can improve basin economics. Relative cost matters because all sell benchmark-linked barrels: a producer with lower cash cost and lower sustaining capital can preserve output and fund reinvestment deeper into an oil-price downturn.

Mining competition is primarily an execution contest. Canadian Naturalâ€™s Horizon and Athabasca Oil Sands Project operations have benefited from reliability enhancement and debottlenecking, while Imperialâ€™s Kearl has reached roughly 280 Mbbls/d gross. Suncorâ€™s competitive response is to improve Base Plant and Syncrude reliability, automate haulage, extend turnaround intervals, advance Mildred Lake Mine Extension East, and lift Fort Hills toward its capacity potential. These are not differentiated products; they are ways to lower the delivered cost of a fungible barrel. Cost leadership and reliability, not brand, determine the moat.

In-situ competition is similarly process-driven. Cenovus reported 644.1 Mboe/d of 2025 Oil Sands production and disclosed brownfield growth at Foster Creek, Christina Lake, and Sunrise. Foster Creek optimization added about 30 Mbbls/d and Christina Lake North targets about 40 Mbbls/d by 2028. This confirms that Suncorâ€™s â€œgrowth from withinâ€■ strategy is industry-wide rather than unique. Modular pads and debottlenecks can add low-risk barrels, but peers are pursuing the same playbook and may set the cost curve. [B-EXT-CVE; archived source register]

Suncorâ€™s integration provides a meaningful but bounded advantage. Access to upgrading, pipeline commitments, storage, trading, and refineries broadens the route to market, and Petro-Canada creates a downstream outlet. During regional dislocation, those assets can capture value elsewhere in the chain and reduce forced-sale risk. Yet the Oil Sands segment itself should receive only its transfer-priced upstream economics. The Refining and Marketing segment earns the refining and retail margin; assigning that downstream profit to Oil Sands would double count integration. The model therefore gives Oil Sands a narrower differential and better operational continuity in base and bull but no separate â€œintegration premiumâ€■ revenue line.

Substitution risk comes from lower-cost global crude, U.S. shale, efficiency, electric vehicles, climate policy, and carbon costs. Oil sands have long lives and low geological decline, but high emissions intensity and fixed infrastructure make them exposed to policy and demand-duration risk. If global demand weakens faster than expected, the marginal long-cycle barrel can lose pricing power even if its cash cost is competitive. Conversely, limited greenfield investment and decline elsewhere can sustain

prices, allowing existing low-decline assets to remain valuable. The correct competitive lens is therefore full-cycle sustaining economics and market access, not reserve size in isolation.

5. Moat at the segment level

The moat is an asset-and-network moat, not customer captivity. Suncor controls enormous long-life resources, already-built mines, upgraders, thermal facilities, pipelines, logistics, and permits that would be extremely expensive and slow for a new entrant to replicate. The data package shows net company 2P reserves of 6.265 billion boe and an analyst-calculated life of about 20 years at FY2025 production. Management separately described roughly 7 billion barrels of 2P reserves and 30 billion barrels of contingent resources for its Investor Day perimeter. These figures use different perimeters and are not reconciled here, but both point to resource duration well beyond the five-year forecast. [data_package Â§0a, lines 42-46; Â§6, lines 248-256]

Permitting, infrastructure, and capital scale are formidable entry barriers. A greenfield mine and upgrader must secure leases, approvals, tailings plans, water rights, pipelines, and billions of dollars before producing. Existing assets can add pads or debottleneck units at a fraction of greenfield risk. The advantage is strongest when Suncor executes reliably: sunk infrastructure turns small production gains into high incremental returns. It weakens when maintenance failures, poor ore quality, or tailings constraints strand that infrastructure.

The moat does not guarantee high margins because the product is priced by the market. Suncor cannot raise prices unilaterally, and a wide WCS differential or low WTI overwhelms operational excellence. The moat instead shifts the cost and resilience curve. Long reserve life reduces the need for expensive exploration; integration diversifies outlets; upgrading converts some heavy barrels into higher-value synthetic crude; and scale supports specialist engineering and automation. These benefits can sustain mid-cycle pretax margins around the modelâ€™s base level, but cyclical margins will remain wide.

Environmental liabilities are both a barrier and a moat leak. The AER requires annual fluid-tailings reporting under Directive 085 and publishes company reports for Suncor Base Plant, Fort Hills, Syncrude Aurora North, and Syncrude Mildred Lake. Suncorâ€™s company-wide decommissioning and restoration provision was C$12.620B at FY2025 and cash settlements were C$505M in FY2025 and C$290M in H1 2026. A new entrant faces the same regulatory burden, but the incumbent owns the accumulated obligation. Delayed treatment or tougher standards can turn a nominal reserve advantage into cash and capital drag. [data_package Â§0a, lines 42-44 and 62-72; B-EXT-AER-TAIL]

On balance, the segment has a durable medium moat for five to ten years, but it is conditional on reliability, market access, and disciplined reclamation. The asset base is hard to replicate; the commodity margin is not. The moat protects the ability to produce and reach market at competitive cost, not the selling price.

6. Historical growth rates

The following table reproduces only disclosed data-package history. â€œ3-year CAGRâ€■ means FY2023 to FY2025 over two compounding intervals because the package has three comparable product-year observations. Every figure is tied to a specific package row; no product dollars are back-solved.

Product / sub-segment	FY2023 rev	FY2024 rev	FY2025 rev	3-year CAGR	Most recent YoY	Data package cite
Oil Sands reportable segment gross revenue	C$18.569B	C$20.818B	C$19.298B	1.9%	(7.3)%	data_package Â§3, Oil Sands table, lines 112-117
Synthetic crude oil and diesel customer revenue	C$18.817B	C$19.336B	C$17.803B	(2.7)%	(7.9)%	data_package Â§4, Oil Sands product row, line 192
Bitumen customer revenue	C$7.218B	C$9.924B	C$9.521B	14.9%	(4.1)%	data_package Â§4, Oil Sands product row, line 193

Arithmetic checks: Oil Sands segment C$20.818B Ã- 0.927 = C$19.298B, synthetic crude and diesel C$19.336B Ã- 0.921 = C$17.803B, and bitumen C$9.924B Ã- 0.959 = C$9.521B. Each tie-out is within 0.1% after rounding. The product rows sum to customer revenue and should not tie to reportable-segment gross revenue because the statements have different intersegment and elimination perimeters. No hidden smoothing is applied.

The history is driven more by commodity price and mix than a conventional â€œsales growthâ€■ curve. Segment physical production rose strongly over the longer FY2021-FY2025 period, while product revenue fell in FY2025 as realizations weakened. Bitumenâ€™s 14.9% two-interval CAGR reflects both a low FY2023 base and greater non-upgraded sales, not a

durable pricing franchise. It would be unsafe to extrapolate that growth mechanically.

7. Management guidance

The data package contains five Oil Sands-specific quotations, all reproduced verbatim from its verified transcript excerpts. They are directional operating anchors, not financial forecasts.

- **Q3 FY2025, data_package Â§6 line 250 â€” â€œhigher volumes, lower unit costs.â€■** This is the clearest operating-leverage objective. The base case assumes meaningful but incomplete cost improvement from the Q2 maintenance spike; bull assumes high reliability makes the two sides reinforce each other; bear assumes downtime reverses the effect.

- **Q4 FY2025, data_package Â§6 line 251 â€” â€œgrowth from within.â€■** This supports brownfield rather than acquisition-led volume growth. The model reflects Fort Hills utilization, in-situ pads, mine extension, and debottlenecking; it does not assume a new greenfield project or a segment acquisition.

- **Q4 FY2025, data_package Â§6 line 252 â€” â€œWe can invest and replace production decline, perhaps even grow it.â€■** The phrase â€œperhapsâ€■ matters. Sustaining production is the floor management believes available with investment; the base case requires moderate growth, but the bear case allows decline when maintenance and cost inflation absorb capital.

- **Q1 FY2026, data_package Â§6 line 253 â€” â€œanother 100,000 barrels a day of upstream production growth.â€■** This is a three-year upstream commitment across Oil Sands and E&P, not an Oil Sands-only guide. The base case allocates 75 Mbbls/d of that specific commitment to Oil Sands and leaves 25 Mbbls/d for E&P, preventing cross-segment double counting. Relative to FY2025 Oil Sands production of 799.4 Mbbls/d, the separate 2031 base assumption of 900 Mbbls/d therefore includes another 25.6 Mbbls/d of explicitly analytical 2029-2031 debottlenecking beyond the three-year commitment allocation. Bull allocates 95 Mbbls/d of the commitment to Oil Sands plus further debottlenecking; bear assumes less than one-third of the group commitment survives offsets from decline and downtime.

- **Q2 FY2026, data_package Â§6 line 254 â€” â€œextending Plant 93 and 94â€™s next turnaround cycle to five years.â€■** Longer Firebag cycles can raise average utilization and reduce unit cost, but only if reliability between turnarounds is maintained. Base credits a modest availability gain; bull credits fuller benefit; bear assumes deferral creates larger later outages.

Management also described Fort Hills stream-day capacity near 220 Mbbls/d, 2025 annual production of 175 Mbbls/d, and a path toward 200 Mbbls/d in 2028; the North Pit opening; modular in-situ development south of Firebag and east of Base Plant; and the resource figures discussed above. The consolidated Investor Day framework targeted a further US$5/bbl enterprise-breakeven reduction and C$2B of incremental annual free funds flow over three years. This appendix uses those as consistency checks, not as guaranteed outputs and not as Oil Sands-only profit guidance. [data_package Â§6, lines 248-256 and 275-281]

8. Forward growth assumptions

Forecast construction and operational bridge

The forecast starts and controls at the DR-cleared total Oil Sands TTM revenue of C$20.888B. No upgraded-versus-bitumen TTM split is assumed. Each case applies one total-segment nominal revenue CAGR for exactly five calendar years to reach its horizon revenue; production, WTI, foreign exchange, differential, reliability, and cost assumptions provide the scenario mechanism rather than an unsupported product-sales bridge. The FY2023-FY2025 customer-revenue product history remains context only.

Operating driver at 2031-06-30	Bear	Base	Bull
Sealed TTM segment revenue control	C$20.888B	C$20.888B	C$20.888B
Total segment revenue CAGR, exactly five years	(4.5987)%	2.5331%	7.1751%

Operating driver at 2031-06-30	Bear	Base	Bull
Horizon segment revenue output	C$16.507B	C$23.671B	C$29.537B
Oil Sands average production assumption	720 Mbbls/d	900 Mbbls/d	970 Mbbls/d
Fort Hills operating expectation	155 Mbbls/d	200 Mbbls/d	215 Mbbls/d
WTI assumption	US$55/bbl	US$75/bbl	US$95/bbl
CAD per USD assumption	1.32	1.35	1.38
WTI-WCS differential assumption	US$20/bbl	US$13/bbl	US$9/bbl
Oil Sands / Fort Hills / Syncrude cash-cost cross-check	C$38 / 45 / 44 per bbl	C$27 / 31 / 32 per bbl	C$23 / 27 / 28 per bbl

The TTM revenue control is historical authority; the forward rows are explicit scenario assumptions, not Suncor guidance. Managementâ€™s Fort Hills, brownfield-growth, reliability, and enterprise-breakeven commentary bounds their direction, while the annual production and cost history tests plausibility. The model does not multiply an invented product volume by an invented product realization, and it does not back-solve royalties or intersegment eliminations to force a product bridge.

Base case growth

Forecast control	TTM anchor	Five-year CAGR	2031-06-30 output	Evidence and mechanism
Oil Sands reportable-segment revenue	C$20.888B	2.5331%	C$23.671B	Production reaches 900 Mbbls/d, Fort Hills reaches 200 Mbbls/d, US$75 WTI and a US$13 differential support mid-cycle realization, and normalized unit costs offset the absence of Q2 2026â€™s price spike.

The constant total-segment CAGR produces C$21.417B in year one, C$21.960B in year two, C$22.516B in year three, C$23.086B in year four, and C$23.671B at the exact horizon. This is conservative relative to the full management volume ambition because commodity revenue does not automatically rise with barrels.

Bear case growth

Forecast control	TTM anchor	Five-year CAGR	2031-06-30 output	Evidence and mechanism
Oil Sands reportable-segment revenue	C$20.888B	(4.5987)%	C$16.507B	US$55 WTI, a US$20 differential, 720 Mbbls/d production, missed Fort Hills ramp, weaker upgrader utilization, and C$38-44/bbl cash costs overpower partial brownfield growth.

The decline is not sharper than recent observed product volatility: both disclosed customer-revenue products fell in FY2025, and Oil Sands reportable-segment revenue declined 7.3%. What makes Bear persistent is the combination of lower global price, a wider differential, and reliability setbacks, rather than â€œmaturation generally.â€■

Bull case growth

Forecast control	TTM anchor	Five-year CAGR	2031-06-30 output	Evidence and mechanism
Oil Sands reportable-segment revenue	C$20.888B	7.1751%	C$29.537B	US$95 WTI, a US$9 differential, 970 Mbbls/d production, Fort Hills at 215 Mbbls/d, modular in-situ additions, and high upgrader availability reinforce each other.

Bull requires both price and execution; volume alone cannot generate this revenue. It is deliberately assigned only a 20% probability because the assumptions are positively correlated and a miss in oil price, differential, or uptime would weaken the outcome materially.

9. Forward segment-profit margin assumptions â€” Earnings (loss) before income taxes

The current TTM margin is 33.3445% on the exact issuer-disclosed basis, calculated as C$6.965B divided by C$20.888B. FY2025 was 27.3%, so TTM reflects a stronger commodity and quarterly mix. Product-level **Earnings (loss) before income taxes** is not disclosed, so no product margin or product profit is fabricated. Each scenario controls from a total-segment margin assumption applied to total-segment revenue. Common depreciation, support cost, and segment overhead remain inside that segment margin; no Corporate and Eliminations or financing item is inserted.

Margin driver	Bear	Base	Bull
Price and differential	US$55 WTI and US$20 WCS discount compress both lines	US$75 WTI and US$13 WCS discount normalize below Q2 2026	US$95 WTI and US$9 WCS discount lift realization
Volume and utilization	720 Mbbls/d; fixed-cost under-absorption	900 Mbbls/d; Fort Hills 200 and steadier upgrading	970 Mbbls/d; high availability and debottlenecking
Cash operating cost	C$38 / 45 / 44 per bbl across operations / Fort Hills / Syncrude	C$27 / 31 / 32 per bbl	C$23 / 27 / 28 per bbl
Incremental royalty pass-through	12%	18%	24%
Annual sustaining plus growth capital diagnostic	C$4.4B	C$4.0B	C$4.7B
Tailings and reclamation	Higher remediation and outage burden	Funded within normal sustaining program	Higher activity funded without disrupting uptime

Case	Horizon segment revenue	Precise Earnings (loss) before income taxes margin used	Display margin	Horizon Earnings (loss) before income taxes	Change versus TTM segment margin	Mechanism
Bear	C$16.507B	16.2113%	16.2%	C$2.676B	(1,713) bps	Low price, a wide differential, outages, and high fixed cost overwhelm lower progressive royalties.
Base	C$23.671B	29.7157%	29.7%	C$7.034B	(363) bps	Better uptime and normalized cash cost partly offset realization below the Q2 2026 spike.
Bull	C$29.537B	40.1700%	40.2%	C$11.865B	683 bps	Price, differential, reliability, and unit cost reinforce each other; the case is not merely a volume multiple.

The base margin declines by more than 100 bps from TTM, so the mechanism is explicit: the TTM included Q2 2026â€™s C$129.59/bbl weighted realization and 44.5% pretax margin, conditions not carried through five years. Higher average output and lower unit cost partially offset that normalization. Bear loses more than 1,700 bps because lower price hits revenue immediately while fixed cost, depreciation, tailings, and maintenance remain sticky. Bull gains almost 700 bps because realization and utilization rise together; the result would fail if only one of those assumptions held.

Oil-price and differential sensitivity

At base horizon volume of 900 Mbbls/d, a C$1/bbl change in weighted realization represents about C$329M of annual gross exposure before royalty effects and basis differences. The following local sensitivities are directional around the base case and are not substitutes for the full scenarios.

Sensitivity around Base	Approximate annual revenue effect	Approximate annual Earnings (loss) before income taxes effect	Key assumption
WTI +US$1/bbl	+C$377M	+C$309M	CAD/USD 1.35; 85% weighted realization pass-through; 18% marginal royalty
WTI -US$1/bbl	(C$377M)	(C$309M)	Symmetric local movement before nonlinear cost responses
WCS differential widens US$1/bbl	(C$244M)	(C$200M)	55% effective heavy/differential exposure after upgrading and logistics dampening

Sensitivity around Base	Approximate annual revenue effect	Approximate annual Earnings (loss) before income taxes effect	Key assumption
WCS differential narrows US$1/bbl	+C$244M	+C$200M	Same local exposure; no downstream crack margin included
Cash operating cost +C$1/bbl	no direct revenue effect	approximately (C$329M)	Applied across 900 Mbbls/d before secondary tax effects

The 55% differential exposure is an analytical hedge factor, not a disclosed hedge ratio. Upgrading, product mix, pipeline access, and downstream integration reduce direct WCS exposure, but the package does not disclose a volumetric commodity hedge book. [DATA GAP: exact TTM hedge volumes, product-level price formulas, and contract-coverage percentages are not disclosed in the data package.]

10. Segment rollup

Each case compounds the same DR-cleared C$20.888B total-segment TTM revenue anchor for exactly five years, then applies the stated total-segment margin on the sealed **Earnings (loss) before income taxes** basis. Product customer-revenue history informs exposure but does not enter the arithmetic. Probabilities are non-uniform: 25% Bear, 55% Base, and 20% Bull. Base receives the highest weight because brownfield growth and some cost improvement are supported by management plans and current projects. Bear exceeds Bull because commodity prices, outage risk, and environmental cost can each impair results independently, whereas Bull requires several favorable conditions simultaneously.

Case	TTM segment revenue control	Five-year revenue CAGR	Horizon segment revenue	Precise margin used	Display margin	Horizon Earnings (loss) before income taxes	Probability
Bear	C$20.888B	(4.5987)%	C$16.507B	16.2113%	16.2%	C$2.676B	25%
Base	C$20.888B	2.5331%	C$23.671B	29.7157%	29.7%	C$7.034B	55%
Bull	C$20.888B	7.1751%	C$29.537B	40.1700%	40.2%	C$11.865B	20%

Rollup checks at displayed precision: C$20.888B compounded at (4.5987)% / 2.5331% / 7.1751% for five years produces C$16.507B / C$23.671B / C$29.537B. Applying precise margins of 16.2113% / 29.7157% / 40.1700% produces C$2.676B / C$7.034B / C$11.865B. Every case ties at the nearest C$1M without a product allocation or plug.

The probability-weighted segment outcome is C$23.053B revenue and C$6.911B of **Earnings (loss) before income taxes**, a 30.0% implied margin. This is useful as a planning mean but should not replace the scenarios: price and differential distributions are skewed, and operating disruptions are lumpy.

Integration boundary and no-double-counting check

Oil Sands revenue is forecast only from its sealed reportable-segment anchor. The disclosed upgraded and bitumen customer-revenue history is non-model context, not an allocation of the TTM anchor and not additional forecast revenue. No R&M customer revenue, refinery throughput, crack spread, retail margin, logistics trading profit, or export cargo profit is included. The narrower Base/Bull differential assumes access and logistics help Oil Sands realization, but any downstream margin on those barrels remains for the R&M segment. Corporate and Eliminations, including intersegment eliminations, must be forecast once by synthesis rather than netted into Oil Sands here.

11. Key risks and wildcards

Bear â€” sustained commodity-price weakness. A five-year WTI environment near US$55 would compress upgraded and bitumen realization. Progressive royalties fall, but the savings do not compensate for lost revenue because fixed operating cost, depreciation, and sustaining capital remain. The segment can stay cash-generative at low prices yet earn well below its current pretax margin.

Bear â€” renewed Western Canadian congestion. TMX eased the historical bottleneck, but CER data show high utilization across major systems. Production growth, pipeline outages, quality constraints, or regulatory delays to optimization could widen WCS. Non-upgraded bitumen takes the direct hit; upgraded products and logistics dampen but do not eliminate it. The bear US$20 differential is not an extreme tail relative to the pre-TMX US$18.70 average reference.

Bear â€” reliability and turnaround execution. Mines and upgraders are complex, integrated systems. Longer turnaround intervals improve average availability only if equipment reliability supports them. Deferred work can create a larger later outage. Q2 2026 demonstrates the combined effect of maintenance, weather, and lower denominator on cost. Fort Hills and

Syncrude have less margin for execution error because their current costs are higher than the core Oil Sands operations measure.

Bear â€” ore quality, weather, fire, and water. Mining economics depend on ore grade and access to the mine face. Wet weather impairs mine movement; wildfire can disrupt in-situ operations and logistics; cold weather can affect equipment; drought or water constraints can limit steam and extraction. These risks are difficult to hedge and can coincide with high commodity prices, producing lost opportunity rather than merely shifted timing.

Bear â€” tailings and reclamation escalation. Directive 085 reporting makes tailings performance visible, and the company already carries a large decommissioning provision. Higher standards, weaker treatment performance, cost inflation, or accelerated closure requirements could raise both operating cost and capital. The modelâ€™s bear capital burden reflects this, but it does not quantify a discrete adverse regulatory judgment because the package provides no asset-level liability schedule.

Bear/Base â€” carbon policy and natural-gas exposure. In-situ steam and upgrading consume energy and generate emissions. A higher carbon price, tighter emissions cap, or unavailable abatement infrastructure can raise cost. Low natural-gas prices help steam and hydrogen economics, while high gas prices hurt. Carbon capture may preserve market access but requires capital and policy support. No unapproved project credit is embedded in base.

Base/Bull â€” Fort Hills ramp and mine extensions. Moving Fort Hills from 175 Mbbls/d in 2025 toward 200 by 2028 is a tangible denominator opportunity, while North Pit and mine-extension work can improve ore access. Base assumes the target is reached and sustained; bull assumes 215 by the horizon; bear assumes operating setbacks drive the asset to 155. The forecast does not equate stream-day capacity with annual average output.

Base/Bull â€” modular in-situ growth. Pads south of Firebag and east of Base Plant can add barrels with existing infrastructure. Peer evidence from Cenovus shows that brownfield thermal projects can deliver tens of thousands of barrels per day. The wildcard is steam-oil ratio and reservoir performance: a volume target reached with excessive steam or declining productivity may add less profit than expected.

Bull â€” operating-system transformation. Autonomous haulage, longer turnaround cycles, better maintenance planning, and standardized work can create a positive loop of higher availability and lower cost. The bull case requires Suncor to approach the best demonstrated peer operating systems while preserving safety and tailings performance. This is plausible but not yet a right; it must be proven through multi-year cost and uptime data.

Bull â€” scarce long-life supply. If global oil demand remains resilient while long-cycle investment stays constrained, existing low-decline resources can earn scarcity rents. Suncorâ€™s reserve duration and installed upgrading capacity would be valuable. The risk is that high prices invite substitution, policy response, or competing supply before the full five-year period elapses.

Data gaps

- [DATA GAP: the data package does not disclose a complete TTM Oil Sands-only sustaining-versus-growth capital schedule on a consistent basis. Scenario capital is analytical.]
- [DATA GAP: a DR-cleared TTM upgraded-versus-non-upgraded production split and exact product-to-reportable-segment revenue bridge are unavailable. The forecast therefore uses neither an invented TTM product split nor a product allocation of the sealed segment anchor.]
- [DATA GAP: a consistent issuer-calculated annual reserve replacement ratio is not disclosed; approximate life is company net 2P divided by production and is not an issuer reserve-life measure.]
- [DATA GAP: volumetric commodity hedge coverage and product-level contract coverage are not separately disclosed.]
- [DATA GAP: the Q2 2026 decommissioning provision lacks a full asset-level roll-forward, preventing a quantified Oil Sands-only reclamation schedule.]

External context source archive

The context sources and local archive hashes are registered in `raw/pulse-cio-20260906T220342+0800/b_oil_sands/external_context_source_register.md`. Live sources include the [Canada Energy Regulator pipeline-throughput snapshot](https://www.cer-rec.gc.ca/en/data-analysis/energy-mark

ets/market-snapshots/2026/market-snapshot-oil-pipeline-throughputs-remained-high-in-2025.html?wbdisable=true), [CER TMX and WCS differential snapshot](https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2025/market-snapshot-trans-mountain-expansion-eases-pipeline-constraints-and-increases-exports-to-overseas-markets.html?wbdisable=false), [Alberta Energy Regulator tailings reports](https://www.aer.ca/data-and-performance-reports/activity-and-data/tailings-management-reports-oil-sands-mining-schemes), [Imperial Oil 2025 Form 10-K](https://www.imperialoil.ca/-/media/imperial/files/2025-sec/2025-sec-form-10k-filing.pdf), [Canadian Natural 2025 annual report](https://www.cnrl.com/content/uploads/2026/03/CNQ_2025-Annual-Report.pdf), and [Cenovus 2025 results](https://www.cenovus.com/News-and-Stories/News-releases/2026/3240864). Direct downloads that failed were retried identically once and were not replaced with cache.

Summary table

Case	Segment TTM+5y Revenue	Exact profit metric	Segment TTM+5y Profit Margin	Segment TTM+5y Profit	Probability
Bear	C$16.507B	Earnings (loss) before income taxes	16.2%	C$2.676B	25%
Base	C$23.671B	Earnings (loss) before income taxes	29.7%	C$7.034B	55%
Bull	C$29.537B	Earnings (loss) before income taxes	40.2%	C$11.865B	20%

Appendix B3 - Exploration and Production

Exploration and Production â€” Segment Deep Dive

Company: Suncor Energy Inc. **Ticker:** SU.TO **Information date:** 2026-09-06 SGT **Forecast anchor:** TTM ended 2026-06-30 **Exact five-year horizon:** 2031-06-30 **Reporting currency:** CAD; dollar amounts are billions unless stated otherwise **Exact segment profit basis:** `Earnings (loss) before income taxes` **Run ID:** `pulse-cio-20260906T220342+0800`

This appendix is a segment operating model, not a valuation. Suncor's historical figures, management quotations, accounting perimeter and classifications come exclusively from the DR-cleared `data_package.md` and the QFR-sealed `statutory_bridge.json`. The sealed bridge SHA-256 is `fab6c20af72b9ac32c4bba687af9a32c3b9f0a764fd222ae134805fcc315ac88`. External sources are used only for competitive and market context.

0. Segment boundary and taxonomy note

Exploration and Production, or E&P, comprises Suncor's offshore East Coast Canada interests and international interests. The disclosed Canadian perimeter includes Hebron, Hibernia, White Rose and the West White Rose development; the international perimeter includes Libya, while Syrian operations remain indefinitely suspended. Libya is presented on an economic basis for operational metrics. The reportable-segment label was stable through FY2021-FY2025, but the economics are not fully comparable across the period because Suncor divested its U.K. E&P portfolio in 2023. That 2023 disposal is the meaningful perimeter boundary: FY2021-FY2022 describe a broader asset set than FY2023 onward. The model therefore reproduces the five-year segment history but gives greater weight to FY2023-FY2025, the TTM period and the current asset perimeter. It does not backfill the disposed U.K. assets or treat their lost revenue as organic decline. [data_package Â§1, paragraph beginning â€œReporting labels have been stableâ€■]

The product-revenue taxonomy also narrows after FY2023. The revenue note disclosed crude oil and natural gas liquids plus a CAD 0.006B natural-gas line in FY2023, but natural gas was no longer shown separately in FY2024-FY2025. This appendix therefore models one combined E&P gross-revenue line rather than inventing separate crude, NGL and gas dollars. Corporate and Eliminations, financing expense and income tax remain outside this segment model and are left for the synthesis stage exactly as required by the sealed statutory bridge. [data_package Â§3a, forecast-driver ledger; Â§4, E&P rows]

1. What this segment actually is

E&P is Suncor's comparatively small, high-operating-leverage conventional and offshore portfolio. Its customers are crude-oil and NGL buyers rather than retail consumers. The segment earns revenue by selling Suncor's working-interest production into market-linked channels. Pricing is primarily commodity-driven: offshore Canadian barrels are exposed to internationally traded crude benchmarks and quality differentials, while the CAD result also reflects foreign-exchange translation. Suncor cannot set the benchmark price. It can improve realized economics through reliability, production timing, crude quality, transportation choices, and capital discipline, but price-taking remains the dominant commercial fact.

The DR-cleared package identifies West White Rose and development drilling at Hebron and Hibernia, but it does not disclose field-level working interests, operators, control rights, capital allocations or project economics. The model therefore does not assume that Suncor controls field schedules or attribute partner economics to Suncor; it uses only the package's segment-level production, revenue and profit disclosures. `[DATA GAP: field-level ownership percentages, operators and control rights are not specified in the DR-cleared package.]`

The asset logic is different by bucket:

- **Hebron and Hibernia** are named in the current development-drilling schedule. The model treats that drilling as support for the combined Canadian production base and a possible offset to decline, not as a disclosed field forecast. The package does not provide their individual production, decline, cost or reserve profiles.
- **White Rose and West White Rose** are part of the named Canadian perimeter, but the package provides no field-level output split. West White Rose is the segment's clearest disclosed development project: it was â€œnearing completionâ€■ in Q2 2026 and remained in the official capital schedule. The model treats a phased contribution as an analyst assumption rather than issuer guidance and does not assign a disclosed field-level volume to it.

- **Libya** can add high-value light-crude exposure, but volumes and cash realization are subject to political, security, export-terminal and payment risk. It is modeled with scenario-specific availability rather than a smooth deterministic growth curve.
- **Syria** is indefinitely suspended. It contributes zero operating production and zero revenue in Bear, Base and Bull. No speculative reopening value is included. Any care-and-maintenance, legal or impairment cost is not separately disclosed in the package and therefore is not fabricated.

E&P is not a traditional high-frequency â€œexploration growthâ€■ platform in this forecast. The disclosed capital agenda is concentrated on completing West White Rose and drilling at Hebron and Hibernia. The go-to-market model is commodity sale; the strategic task is to turn finite reserves into cash at acceptable unit economics while replacing decline economically. That makes project selection, uptime and balance-sheet patience more important than branded pricing power.

2. Current economics at the TTM anchor

The four reported quarters ending 2026-06-30 produced gross revenue of CAD 3.223B: Q3 2025 CAD 0.665B, Q4 2025 CAD 0.450B, Q1 2026 CAD 0.961B and Q2 2026 CAD 1.147B. The exact sealed TTM `Earnings (loss) before income taxes` was CAD 1.050B, giving a 32.6% margin on the exact segment metric. This is not an operating margin and is not renamed as one. [data_package Â§5, E&P quarterly table; Â§3a, TTM bridge row â€œExploration and Productionâ€■]

The TTM pattern was sharply back-end weighted. E&P quarterly gross revenue rose from CAD 0.450B in Q4 2025 to CAD 0.961B in Q1 2026 and CAD 1.147B in Q2 2026. The exact pretax-margin percentage moved from 13.6% to 39.8% and 40.5%. Q2 E&P production was 70.8 mboe/d, up from 59.7 mboe/d a year earlier, while the disclosed Canada operating netback was CAD 92.78 per barrel versus CAD 56.20 in the comparative quarter. This combination shows the segment's two-sided operating leverage: restored or incremental barrels and stronger netbacks can move profit much faster than annual averages, while a price or outage reversal can unwind the same leverage. [data_package Â§0a, longest KPI history and latest netback table; Â§5, E&P quarterly table; Â§6, E&P commentary]

FY2025 provides a lower-cycle comparison. Gross revenue was CAD 2.509B and `Earnings (loss) before income taxes` was CAD 0.526B, a 21.0% margin. E&P contributed only 4.79% of consolidated FY2025 gross revenue, so it is not the principal determinant of Suncor's total revenue. It can nevertheless matter disproportionately at the margin because its segment profit varies with commodity realizations, offshore uptime and Libya availability. [data_package Â§1, FY2025 revenue table; Â§3, E&P historical table]

Capital intensity is high even though the package does not disclose a clean E&P-only capex series. Company-wide FY2025 capital expenditures were CAD 5.856B, including CAD 3.162B of asset sustainment and maintenance and CAD 2.496B of economic investment, with the balance largely capitalized interest. E&P projects named in the current schedule were West White Rose and development drilling at Hebron and Hibernia. Because the segment's share of those totals is not stated, this appendix uses project/activity indices rather than allocating corporate capex to E&P. `[DATA GAP: E&P-only sustaining capex, growth capex and capitalized-interest history are not separately disclosed in the DR-cleared data package.]` [data_package Â§0a, capital inventory; Â§7, capital allocation history]

Product mix is also only partly separable. FY2025 customer revenue identified CAD 2.509B of crude oil and NGL revenue, equal to the reportable segment's gross revenue that year. Natural gas was last separately shown at only CAD 0.006B in FY2023 and was not separately shown thereafter. The current product mix is therefore economically crude-dominant, but no precise TTM crude/NGL/gas split is published in the package. `[DATA GAP: TTM revenue and production by Hebron, Hibernia, White Rose/West White Rose, Libya and Syria are not separately disclosed in the data package.]`

3. Unit economics

E&P revenue can be reduced to three drivers: saleable production, realized CAD price per unit, and mix/capture. Production is the output of reservoir decline, development wells, project start-ups and facility uptime. Realized price combines global crude benchmarks, quality differentials, timing and CAD translation. Mix/capture reflects the relative share of Canadian offshore crude, Libya and small NGL/gas contributions. Because gross revenue is before royalties, royalties do not reduce the reported gross-revenue line; they reduce the economics that ultimately reach `Earnings (loss) before income taxes`.

The TTM model starts with CAD 3.223B of segment gross revenue. It uses Q2 2026 production of 70.8 mboe/d as a disclosed current run-rate proxy, not as a fabricated TTM average. The package gives annual E&P production of 60.8 mboe/d for

FY2025 but does not provide each of the four TTM quarters. The difference shows stronger current segment output than the FY2025 average, but the package does not attribute the increase to White Rose or any other field. [DATA GAP: exact TTM-average E&P production is not available; Q2 2026's 70.8 mboe/d is used only as the model's run-rate production anchor.]

Earnings (loss) before income taxes is much more volatile than revenue because offshore costs are partly fixed. Platform staffing, marine and aviation support, inspections, integrity work, logistics, insurance and maintenance continue even when production falls. Development drilling and workovers can raise near-term spending before generating barrels. Conversely, a high-uptime quarter can spread these costs over more units. This explains why the margin on Earnings (loss) before income taxes fell from 62.9% in FY2023 to 31.0% in FY2024 and 21.0% in FY2025, then recovered to 32.6% in the TTM period. Commodity prices, dispositions, project activity, impairments and outage timing can all affect the comparison; the package does not disaggregate those effects into a clean cost bridge. [data_package Â§3, E&P historical table; Â§3a, TTM bridge]

Royalties are price-sensitive and jurisdiction-specific. Company-wide royalties were CAD 3.469B in FY2025 and CAD 2.454B in H1 2026, but those totals span Oil Sands and E&P. Applying them pro rata to E&P would be false precision. The scenarios instead model the direction of the royalty burden: a higher realized-price case pays a higher royalty share and therefore does not convert every revenue dollar into profit; a low-price case gets some royalty relief, but that relief is insufficient to offset lower revenue and weak fixed-cost absorption. [DATA GAP: E&P-only royalty dollars and effective royalty rate are not separately disclosed.] [data_package Â§0a, royalties table]

The clearest current netback evidence is Canadian E&P's Q2 2026 operating netback of CAD 92.78 per barrel, versus CAD 56.20 a year earlier. It is a non-GAAP figure after royalties, transportation and net operating expenses, per barrel of disclosed Canadian sales volumes. It is an excellent sensitivity indicator but not a sufficient profit bridge: it excludes international mix and does not by itself reproduce segment pretax earnings, depreciation, exploration expense, project charges or impairments. The model therefore uses it to support the direction and magnitude of scenario margins, not as a substitute accounting metric. [data_package Â§0a, latest official realizations table]

Reinvestment is unavoidable in a depleting upstream business. The package identifies Hebron/Hibernia development drilling and West White Rose completion but does not disclose their sustaining-capital needs, field decline rates or Libya rehabilitation spending. The model therefore uses development-activity indices rather than currency allocations. Cutting activity can improve one year's free cash flow but may accelerate later decline; overspending cannot create durable value if production is delayed or price does not cover full-cycle capital. The relevant unit economic is not merely lifting cost: it is the after-royalty, after-sustaining-capital value of a reliable barrel over the remaining reservoir life.

Depletion and reserve life are central but incompletely disclosed at the segment level. The data package calculates approximately 20.0 years of company-wide net proved-plus-probable reserve life for FY2025, while an Investor Day claim uses a different perimeter and cites 25 years. Neither is an E&P-only reserve-life measure, so this appendix does not assign 20 or 25 years to E&P. The package's FY2021-FY2025 E&P production history declines from 87.5 mboe/d to 60.8 mboe/d, but the 2023 U.K. disposal means that series cannot isolate natural field decline. The five-year cases therefore test decline offset without claiming that any field is protected through a specific end date. [DATA GAP: E&P-only proved and probable reserves, reserve life, reserve replacement and depletion by field are not disclosed in the package.] [data_package Â§0a, longest KPI histories; Â§1, perimeter note]

4. Competitive dynamics

E&P competes in two markets. In the product market, commodity barrels compete for refinery demand. In the capital market, offshore development competes with alternative upstream projects. The DR-cleared package does not disclose field-level breakevens, benchmark realization bridges, transportation routes or project returns, so this appendix does not claim a precise competitive ranking against other basins. Bear, Base and Bull instead use explicit production, realization and mix indices without importing external Suncor asset economics. [DATA GAP: field-level breakevens and full-cycle returns are not disclosed in the package.]

Market share is not a useful moat measure here. Suncor's disclosed E&P production was 60.8 mboe/d in FY2025 and 70.8 mboe/d in Q2 2026, but the package does not separate Newfoundland and Libya or provide a matching regional denominator. A precise regional market-share calculation would therefore mix perimeters and is not made. [data_package Â§0a, KPI history]

Pricing power is weak at the product level. The buyer can substitute another suitable crude grade, subject to refinery configuration, transport and quality. Any protection must come from asset quality, reliability and cost position rather than customer lock-in, but the package does not quantify E&P's field-level cost rank. Offshore production can have attractive fixed-cost absorption when uptime and volume are strong; that analytical advantage does not immunize the business from commodity prices.

The medium-term oil balance is a genuine two-sided uncertainty. The IEA's Oil 2025 outlook projects oil demand reaching a plateau around 105.5 mb/d by 2030 while global production capacity rises faster, creating potential surplus and price pressure if OPEC+ supply is sustained. [IEA Oil 2025 executive summary](https://www.iea.org/reports/oil-2025/executive-summary) OPEC's 2025 outlook takes a stronger-demand view and expects interregional crude and condensate trade to rise from 36.8 mb/d in 2024 to 41.7 mb/d by 2030. [OPEC World Oil Outlook 2025 executive summary](https://www.opec.org/assets/assetdb/woo-2025-1.pdf) These conflicting primary-source views justify separate realized-price paths rather than a single â€œconsensusâ€■ forecast.

West White Rose has schedule and ramp risk. The only DR-cleared timing fact is that the project was â€œnearing completionâ€■ in the Q2 2026 official MD&A. The package provides no first-oil date, annual ramp schedule, ownership-based Suncor volume contribution or operator schedule. Base therefore uses a staged 2027-2028 contribution as an explicit analyst assumption; Bear tests slippage and underperformance, while Bull tests prompt completion and a stronger ramp. No external operator schedule is used. [data_package Â§6, E&P bullet 3]

Libya is structurally lower-cost in geological potential but much higher-risk in availability and cash conversion. The U.S. EIA notes that political factions and militias have repeatedly used oil exports as leverage and that civil unrest has caused major production disruptions. It also describes Libya's large light, sweet crude resource base. [U.S. EIA Libya country analysis](https://www.eia.gov/international/content/analysis/countries_long/libya/) The competitive advantage is therefore conditional: attractive crude and reservoirs do not create dependable earnings when terminals, fields or payment systems are interrupted.

5. Segment-level moat

The segment has a potential **asset and infrastructure moat, not a customer or pricing moat**. Capital-intensive offshore systems, regulatory approvals, engineering capability, safety requirements and partner coordination can create high entry barriers. Once capital is sunk, incremental barrels can benefit from fixed-cost absorption. However, the package does not disclose field infrastructure specifications, remaining project lives, ownership shares or asset-level returns, so the magnitude and duration of that advantage are not quantified here.

That moat is narrower than it first appears. Suncor does not control benchmark prices, and the package does not establish field-level operating control or cost leadership. Installed infrastructure can become a liability if reservoir productivity falls or integrity work rises. The economic moat therefore depends on economically recoverable resources, high uptime and disciplined incremental capital. If any fails, the fixed-cost base can destroy rather than protect margin.

The package's named development drilling at Hebron and Hibernia and completion work at West White Rose establish that reinvestment channels exist. They do not establish field-level reserves, project returns, ownership economics or a cost advantage over competing basins. The model therefore treats development success as a scenario lever, not as evidence that these projects automatically earn superior returns. [data_package Â§0a, capital and project inventory; Â§6, E&P commentary]

Libya has resource scarcity but not institutional durability. Its attractive light crude and resource depth could support strong economics in a stable environment, yet the history of disruptions means the asset cannot be valued like a contractually protected annuity. Syria contributes no moat value in this forecast because production remains suspended in every case.

Over five to ten years, the segment moat is **moderate but depleting**. Infrastructure and reservoir access can protect cash generation through 2031, especially if West White Rose ramps and existing-field drilling works. It is not a self-renewing moat: every barrel produced consumes the reserve base, and replacement requires new capital or discoveries. Without disclosed E&P reserve replacement, field-level reserves or project break-evens, the evidence does not support calling this a 20-year compounder by itself. The segment can be valuable as a cash-generating satellite within integrated Suncor, but integration benefits should not be confused with standalone E&P pricing power.

6. Historical growth rates â€” reproduced from the data package

The five-year segment history is shown because it is issuer-disclosed, but the FY2021-FY2022 figures include the subsequently divested U.K. portfolio. The cleanest current-perimeter growth comparison begins in FY2023. â€œThree-year

CAGRâ€■ below means FY2022 to FY2025 over three compounding intervals for the segment row; the product row has only FY2023-FY2025 dollars and therefore shows the two-interval CAGR explicitly. No product dollars are back-solved.

Product / sub-segment	FY2021 rev	FY2022 rev	FY2023 rev	FY2024 rev	FY2025 rev	Historical CAGR	Most recent YoY	Data package cite
E&P segment gross revenue	CAD 2.978B [Â§3 E&P gross-revenue row]	CAD 4.331B [Â§3 E&P gross-revenue row]	CAD 2.689B [Â§3 E&P gross-revenue row]	CAD 2.798B [Â§3 E&P gross-revenue row]	CAD 2.509B [Â§3 E&P gross-revenue row]	FY2022-25: (16.6%) [Â§3 E&P gross-revenue row]	FY2025: (10.3%) [Â§3 E&P YoY row]	[data_package Â§3, E&P table, rows â€œGross revenueâ€■ and â€œYoY percentâ€■]
Crude oil and natural gas liquids customer revenue	n/s [Â§4 E&P crude/NGL row]	n/s [Â§4 E&P crude/NGL row]	CAD 2.683B [Â§4 E&P crude/NGL row]	CAD 2.798B [Â§4 E&P crude/NGL row]	CAD 2.509B [Â§4 E&P crude/NGL row]	FY2023-25: (3.4%) [calculated from Â§4 values]	FY2025: (10.3%) [Â§4 E&P crude/NGL row]	[data_package Â§4, product table, E&P crude/NGL row]
Natural gas customer revenue	n/s [Â§4 E&P natural-gas row]	n/s [Â§4 E&P natural-gas row]	CAD 0.006B [Â§4 E&P natural-gas row]	Not separately shown [Â§4 E&P natural-gas row]	Not separately shown [Â§4 E&P natural-gas row]	n/m [Â§4 E&P natural-gas row]	n/m [Â§4 E&P natural-gas row]	[data_package Â§4, product table, E&P natural-gas row]

Arithmetic checks pass for the disclosed segment series: CAD 4.331B Ã- (1 âˆ’ 37.9%) = CAD 2.690B versus CAD 2.689B reported; CAD 2.689B Ã- 1.041 = CAD 2.799B versus CAD 2.798B; and CAD 2.798B Ã- (1 âˆ’ 10.3%) = CAD 2.510B versus CAD 2.509B. Each difference is rounding and well within 2%. The product line also ties: CAD 2.798B Ã- (1 âˆ’ 10.3%) = CAD 2.510B versus CAD 2.509B. FY2021 to FY2022 likewise ties at approximately 45.4%. No row requires back-solving.

The 2023 decline cannot be treated as a pure volume/price signal because the U.K. divestiture changed the perimeter. The subsequent FY2023-FY2025 crude/NGL revenue CAGR of negative 3.4% is more comparable but still mixes commodity price, volume, outages and project timing. The latest quarterly cadence then turned positive: gross revenue reached CAD 1.147B in Q2 2026, up 72.5% year over year, and exact pretax margin reached 40.5%. [data_package Â§5, E&P quarterly table]

7. Management guidance from the data package

Management provided less direct E&P guidance than it did for Oil Sands and Refining and Marketing. All relevant package items are preserved below without supplementing them from fresh Suncor sources.

- **Q3 FY2025 call, 2025-11-05 â€" Rich Kruger, CEO:** â€œa year-on-year-on-year capital expenditure at less than $6 billion a year.â€■ [data_package Â§6, E&P bullet 1] This is a company-wide capital-discipline anchor given in response to a question about West White Rose. It constrains the ability to solve every offshore decline with spending; the Base case assumes project sequencing within the consolidated ceiling rather than a large E&P capital surge.
- **Q1 FY2026 call, 2026-05-06 â€" Troy Little, CFO:** â€œmaintaining capital discipline.â€■ [data_package Â§6, E&P bullet 2] This supports phased development and a hurdle-rate approach. It does not quantify E&P capex, field decline or project returns, so the forecast does not manufacture those figures.
- **Q2 FY2026 report, 2026-08-04 â€" official MD&A:** West White Rose was â€œnearing completion.â€■ [data_package Â§6, E&P bullet 3] This is the sole project-timing anchor. Base assumes a staged 2027-2028 contribution after completion; Bull assumes prompt completion and a strong ramp; Bear assumes delay and underperformance. These timings are analyst assumptions because the package provides no first-oil or annual ramp guide.
- **Current operating context:** The official capital schedule continued to identify West White Rose plus development drilling at Hebron and Hibernia. E&P quarterly production rose to 70.8 mboe/d in Q2 2026 from 59.7 mboe/d a year earlier. Libya remained politically exposed and Syria remained indefinitely suspended. [data_package Â§6, E&P closing paragraph] This supports growth from project execution but rules out treating recent momentum as risk-free.

There is no management-provided E&P five-year production target, asset-level decline rate, E&P capital budget, field-level break-even, or West White Rose contribution net to Suncor in the package. `[DATA GAP: management has not provided a complete E&P-specific five-year volume, capex or profit guide in the data package.]` The scenario ranges are therefore analyst cases anchored to disclosed segment economics, not disguised guidance.

8. Forward growth assumptions â€" explicit and bottom-up

The model compounds exactly five calendar years from the TTM ended 2026-06-30 to 2031-06-30. The revenue formula is:

`TTM gross revenue Ã- production factor Ã- realized CAD price factor Ã- mix/capture factor.`

Production starts from the disclosed Q2 2026 run rate of 70.8 mboe/d because the package does not provide an exact TTM average. The price index starts at 100 and includes benchmark price, CAD translation and differential effects; it is an analytical index, not a claimed forward curve. Mix/capture includes the changing contribution of Canadian offshore production, Libya and NGL/gas. Syria remains zero throughout.

Base case growth assumptions

Product / driver	Historical CAGR	Latest YoY	Mgmt FY+1 guide	Base CAGR TTM to TTM+5y	Justification
E&P gross revenue; crude/NGL plus undisclosed gas	FY2023-25: (3.4%)	Q2 2026: 72.5%	West White Rose â€œnearing completionâ€■; capex below CAD 6B company-wide	2.17%	West White Rose and drilling offset mature decline; realized CAD price eases slightly, preventing volume growth from fully reaching revenue.
Production run rate	FY2021-25: (8.7%)	Q2 2026: +18.6% versus 59.7 mboe/d	Development drilling at Hebron/Hibernia; West White Rose completion	2.47%	70.8 mboe/d rises to 80.0 by 2031 as new barrels more than offset underlying decline.
Realized CAD price index	n/a	Canada netback rose to CAD 92.78/bbl from CAD 56.20	No price guide	(0.50%)	IEA surplus risk limits price durability; no collapse is assumed because global supply remains geopolitically exposed.
Mix/capture factor	n/a	Libya and asset mix not separated	Syria suspended; Libya politically exposed	0.20%	Slight uplift from higher-value offshore and stable Libya mix; no Syria restart value.

The historical production CAGR in the table is the simple FY2021 87.5 mboe/d to FY2025 60.8 mboe/d comparison from the package; it is heavily affected by the 2023 U.K. disposal and is not used mechanically. The Base production path is 72.6, 74.3, 76.2, 78.1 and 80.0 mboe/d at each successive horizon anniversary. The realized-price index declines to 97.5 by 2031. Gross revenue grows from CAD 3.223B to CAD 3.587B.

The Base mechanism is non-uniform by driver. The established Canadian production base carries decline risk, while the package-identified Hebron/Hibernia drilling offsets part of the fall. West White Rose provides the modeled net growth through a phased analyst-assumption ramp rather than appearing instantly. Libya remains intermittently available but does not receive heroic expansion capital. Syria stays at zero. Because field-level output is undisclosed, these effects are not presented as issuer-provided field allocations. This case deliberately does not extrapolate Q2 2026's 72.5% revenue growth.

Bull case growth assumptions

Product / driver	Historical CAGR	Latest YoY	Mgmt FY+1 guide	Bull CAGR TTM to TTM+5y	Justification
E&P gross revenue; crude/NGL plus undisclosed gas	FY2023-25: (3.4%)	Q2 2026: 72.5%	West White Rose â€œnearing completionâ€■	7.49%	Strong West White Rose ramp, successful development drilling, high uptime, stable Libya and firm CAD realizations compound together.
Production run rate	FY2021-25: (8.7%)	Q2 2026: +18.6%	Development drilling continues	5.38%	70.8 mboe/d rises to 92.0 by 2031; project delivery and reservoir response exceed Base.
Realized CAD price index	n/a	Canada netback CAD 92.78/bbl	No price guide	1.50%	OPEC's stronger trade/demand view and geopolitical supply restraint support price; no extreme supercycle is assumed.
Mix/capture factor	n/a	Not separately disclosed	Libya remains in perimeter; Syria suspended	0.50%	Reliable Libya and a richer offshore mix add modest capture; Syria still contributes zero.

The Bull production path is 74.6, 78.6, 82.8, 87.3 and 92.0 mboe/d. The price index reaches 107.7, while revenue rises to CAD 4.626B. Bull is not a mechanical uplift of Base: it assumes prompt commissioning and strong reservoir response, fewer outages, sustained Libya exports and modestly firmer pricing. It also assumes operating reliability avoids a cost surge even as activity rises. The ramp timing and Suncor volume effect are analyst assumptions because the package omits first-oil guidance, annual project cadence, project interest and net contribution.

Bear case growth assumptions

Product / driver	Historical CAGR	Latest YoY	Mgmt FY+1 guide	Bear CAGR TTM to TTM+5y	Justification
E&P gross revenue; crude/NGL plus undisclosed gas	FY2023-25: (3.4%)	Q2 2026: 72.5%	Capital discipline limits rescue spending	(7.59%)	Mature-field decline, West White Rose delay/underperformance, Libya disruption and lower prices reinforce each other.
Production run rate	FY2021-25: (8.7%)	Q2 2026: +18.6%	West White Rose not quantitatively guided	(4.93%)	70.8 mboe/d falls to 55.0 by 2031 as decline and outages outrun development additions.
Realized CAD price index	n/a	Canada netback CAD 92.78/bbl	No price guide	(3.00%)	Supply-capacity growth and demand plateau compress benchmark prices and netbacks.
Mix/capture factor	n/a	Not separately disclosed	Libya exposed; Syria suspended	0.20%	Small quality/currency offset cannot overcome Libya shut-ins and weaker asset mix.

The Bear production path is 67.3, 64.0, 60.8, 57.8 and 55.0 mboe/d. The realized-price index falls to 85.9, and gross revenue declines to CAD 2.172B. Bear does not simply apply a lower percentage to all lines. The central mechanism is a timing and reliability failure: West White Rose slips or ramps below plan, mature Canadian assets decline, and Libya loses 18-24 cumulative months of availability. Lower prices reduce royalties but also deter discretionary drilling. Syria remains suspended, so there is no offsetting reopening windfall.

Five-year revenue cadence and thesis-consistency check

Case	TTM anchor	2027-06-30	2028-06-30	2029-06-30	2030-06-30	2031-06-30
Bear gross revenue	CAD 3.223B	CAD 2.978B	CAD 2.752B	CAD 2.543B	CAD 2.350B	CAD 2.172B
Base gross revenue	CAD 3.223B	CAD 3.293B	CAD 3.364B	CAD 3.437B	CAD 3.511B	CAD 3.587B
Bull gross revenue	CAD 3.223B	CAD 3.465B	CAD 3.724B	CAD 4.003B	CAD 4.303B	CAD 4.626B

The cadence explicitly rejects a straight-line extrapolation of Q2 2026. The Base case moves from a 72.5% quarterly YoY revenue comparison to low-single-digit five-year growth because the comparison quarter was weak, the TTM already includes a large recovery, mature-field decline persists, and price is normalized slightly lower. Bull preserves strong volume growth but not 72.5% revenue growth. Bear assumes the recent recovery proves temporary.

9. Forward `Earnings (loss) before income taxes` margin assumptions

The exact margin is `Earnings (loss) before income taxes` divided by segment gross revenue. The TTM anchor is 32.6%. It is not an operating margin. No Corporate and Eliminations, financing expense or tax line is allocated to E&P.

Case	TTM exact margin	2031 exact margin	Change	Cost / royalty / project mechanism
Bear	32.6%	6.0%	(2,660) bps	Fixed-cost under-absorption, weaker netback, project delay, higher unit maintenance and possible impairment overwhelm royalty relief.
Base	32.6%	29.0%	(360) bps	Volume offsets decline, but price normalization, mature-field work and West White Rose depreciation keep margin below the TTM recovery level.
Bull	32.6%	44.0%	+1,140 bps	High uptime, successful ramp, stronger mix and lower operating cost per boe outweigh higher price-linked royalty burden and depreciation.

The Bear margin contraction is intentionally nonlinear. The first step down reflects price normalization and lower volume; later steps reflect fixed-cost absorption and development underperformance. The horizon margin remains positive because

operating production and royalty relief survive, but only a small pretax return remains. A major impairment could make a reported period negative even if normalized field cash flow is positive; no separate impairment amount is forecast because the package does not disclose a reliable field-level basis.

The Base margin falls modestly despite revenue growth. West White Rose contributes barrels, but the ramp brings depreciation and maintenance, while mature-field drilling continues. The TTM's 32.6% margin benefited from a strong Q2 netback and rising output, so using it unchanged would overstate normalized economics. Base ends near 29%, above FY2025's 21% but below the TTM peak cadence.

Bull expands margin because volume and uptime improve faster than the cost base. The operating-cost-per-boe index falls to 92 from 100 even as total activity grows. This is not an assumption that absolute cost falls by 8%; it means production grows faster than relevant operating cost. Higher prices increase the royalty burden, preventing one-for-one conversion of price to profit. The margin remains below the 60%-plus outcomes seen in FY2021-FY2023, avoiding reliance on the prior U.K. perimeter or an extreme commodity environment.

Case	Operating cost per boe index, TTM=100	Royalty burden direction	Development/capex activity index, TTM=100	Depletion / project charge direction	Geopolitical availability
Bear	125	Lower rate, lower dollars	85	Higher per barrel; impairment risk	Libya disrupted; Syria zero
Base	105	Near anchor; modestly price-sensitive	95 by 2031 after near-term WWR work	Higher absolute depreciation as WWR ramps	Libya intermittent but available; Syria zero
Bull	92	Higher rate and dollars	115	Higher absolute depreciation but lower burden per barrel	Libya stable; Syria zero

These indices are explicit forecast assumptions, not historical facts. The project index is not a currency allocation. In Base, activity can be above 100 during completion and initial drilling before settling to 95 at the horizon; the table reports the horizon state. In Bear, reduced activity does not help margin enough because it accelerates decline and leaves fixed infrastructure underused. In Bull, higher activity earns a return through stronger production rather than being treated as an automatic cost penalty.

Annual margin and profit cadence

Case / exact metric	TTM 2026-06-30	2027-06-30	2028-06-30	2029-06-30	2030-06-30	2031-06-30
Bear margin on `Earnings (loss) before income taxes`	32.6%	24.0%	18.0%	13.0%	9.0%	6.0%
Bear `Earnings (loss) before income taxes`	CAD 1.050B	CAD 0.715B	CAD 0.495B	CAD 0.331B	CAD 0.212B	CAD 0.130B
Base margin on `Earnings (loss) before income taxes`	32.6%	31.5%	31.0%	30.5%	30.0%	29.0%
Base `Earnings (loss) before income taxes`	CAD 1.050B	CAD 1.037B	CAD 1.043B	CAD 1.048B	CAD 1.053B	CAD 1.040B
Bull margin on `Earnings (loss) before income taxes`	32.6%	35.0%	38.0%	40.0%	42.0%	44.0%
Bull `Earnings (loss) before income taxes`	CAD 1.050B	CAD 1.213B	CAD 1.415B	CAD 1.601B	CAD 1.807B	CAD 2.035B

Base profit is approximately flat despite rising revenue because the exact margin normalizes lower. Bear profit falls faster than revenue because fixed costs and project disappointment compress margin. Bull profit grows faster than revenue through utilization and unit-cost leverage. Those are three different economic mechanisms, not a uniform scalar.

10. Segment rollup â€” bottoms-up arithmetic

Because the package does not separately disclose current crude, NGL and gas revenue, the only honest product rollup is one combined E&P gross-revenue line. The volume-price-mix bridge in Section 8 makes that line reconstructable. A fabricated field revenue split would look more detailed but be less accurate.

Case	Combined crude/NGL/gas gross revenue	Natural gas separately modeled	Product sum	Segment revenue	Difference
Bear	CAD 2.172B	CAD 0.000B; included in combined line	CAD 2.172B	CAD 2.172B	CAD 0.000B
Base	CAD 3.587B	CAD 0.000B; included in combined line	CAD 3.587B	CAD 3.587B	CAD 0.000B
Bull	CAD 4.626B	CAD 0.000B; included in combined line	CAD 4.626B	CAD 4.626B	CAD 0.000B

The separate natural-gas modeled amount is zero only to prevent double counting; it does not mean actual gas production is zero. Natural gas is included in the combined segment line because the issuer stopped showing it separately after FY2023.

Case	Production endpoint	Price index endpoint	Mix factor CAGR	Revenue CAGR	Segment revenue	Exact profit margin	`Earnings (loss) before income taxes`
Bear	55.0 mboe/d	85.9	0.20%	(7.59%)	CAD 2.172B	6.0%	CAD 0.130B
Base	80.0 mboe/d	97.5	0.20%	2.17%	CAD 3.587B	29.0%	CAD 1.040B
Bull	92.0 mboe/d	107.7	0.50%	7.49%	CAD 4.626B	44.0%	CAD 2.035B

The arithmetic is exact within rounding. Bear: CAD 3.223B Ã- the five-year compounded production, price and mix factors = CAD 2.172B; CAD 2.172B Ã- 6.0% = CAD 0.130B. Base: the same bridge equals CAD 3.587B; Ã- 29.0% = CAD 1.040B. Bull: the bridge equals CAD 4.626B; Ã- 44.0% = CAD 2.035B. Product and segment revenue reconcile with zero residual, well within the 1% requirement.

Probabilities are 30% Bear, 50% Base and 20% Bull. The Bear weight is intentionally meaningful because commodity price and Libya/project timing risks can coincide. Base has the highest weight because West White Rose was nearing completion and recent Canadian production improved, but its margin is normalized below the TTM level. Bull receives 20% because it requires simultaneous success in project ramp, mature-field drilling, uptime, Libya availability and price.

The probability-weighted horizon output is CAD 3.370B of segment revenue and CAD 0.966B of `Earnings (loss) before income taxes`, implying a 28.7% revenue-weighted exact pretax margin. It is calculated from scenario-weighted outcomes rather than as a fourth operating scenario. These figures are context for synthesis only; the combined model should retain the three discrete cases rather than replace them with the average.

11. Key risks and wildcards

[Bear] Commodity-price and CAD realization risk. E&P is a price taker. A global capacity surplus or weaker demand can depress benchmark prices, while a stronger Canadian dollar can reduce CAD realization. The IEA's medium-term supply-capacity warning is a credible mechanism for the Bear price path. Royalty relief helps but cannot offset the full revenue loss.

[Bear] Mature-field decline exceeds drilling additions. Hebron and Hibernia require development work to arrest decline. If reservoir response disappoints or partner schedules slip, the segment can spend capital without holding production. The 70.8 mboe/d Q2 run rate would then be a temporary high rather than a stable base.

[Bear] West White Rose delay or underperformance. â€œNearing completionâ€■ reduces construction risk but does not eliminate commissioning, drilling, ramp or reservoir risk. A one-quarter delay is manageable; a multi-year delay or weak ramp damages both volume and capital efficiency. The package does not disclose field-level operator or control rights, so schedule controllability cannot be assessed.

[Bear] Libya disruption. Fields, pipelines, terminals or payment channels can be interrupted by political conflict. The Bear case assumes substantial cumulative downtime. The risk is not merely lower production: prolonged interruption can require restart expenditure and increase receivable or impairment risk.

[Bear/Base] Offshore reliability and weather. Fixed facilities and FPSOs are exposed to turnaround, integrity, weather and marine-logistics events. Production can move abruptly between quarters, causing strong operating leverage in both directions. Safety or environmental incidents could produce costs well beyond normal maintenance.

[Base] Capital rationing. Company-wide capex discipline is rational, but the E&P portfolio must still fund West White Rose completion, Hebron/Hibernia drilling and sustaining work. If Oil Sands or downstream projects win the internal capital competition, E&P may decline faster. If E&P receives too much capital at weak prices, full-cycle returns suffer.

[Base] Reserve-life uncertainty. The company-wide approximate reserve life does not establish E&P durability. Missing field-level reserves and replacement data reduce confidence in the post-2031 tail. The Base case is therefore a five-year operating view, not proof of a long-duration compounder.

[Bull] West White Rose ramp exceeds expectations. Strong commissioning and high well productivity could lift volumes faster than modeled. This would also spread fixed costs and raise the exact pretax margin; no field-level volume or facility-integration claim is treated as disclosed.

[Bull] Libya normalization. Sustained political stability, reliable exports and rehabilitation could increase high-value light-crude contribution. Bull includes stability but not a major greenfield expansion, leaving upside if conditions improve more than expected.

[Bull] Commodity scarcity premium. The Bull price path is modest. A period of geopolitical supply restraint or underinvestment could produce much higher realizations and netbacks. Because royalties rise with price, the profit sensitivity would be strong but not one-for-one.

[All cases] Syria optionality is excluded. A lawful, economically viable restart would be upside not in the model. Continued suspension is already assumed, so Syria cannot worsen operating production below zero, though legal, impairment or remediation costs remain possible and unquantified.

[All cases] Accounting volatility. `Earnings (loss) before income taxes` can reflect items not captured in operating netback, including depreciation, exploration expense, gains/losses and impairments. The model forecasts a normalized segment outcome. Reported annual results may deviate materially even if production and price assumptions are broadly right.

Scenario summary

Case	Segment TTM+5y Revenue	Exact profit metric	Segment TTM+5y Profit Margin	Segment TTM+5y Profit	Probability
Bear	CAD 2.172B	Earnings (loss) before income taxes	6.0%	CAD 0.130B	30%
Base	CAD 3.587B	Earnings (loss) before income taxes	29.0%	CAD 1.040B	50%
Bull	CAD 4.626B	Earnings (loss) before income taxes	44.0%	CAD 2.035B	20%

The segment is best understood as a volatile, capital-intensive cash generator with a real installed-infrastructure advantage but little commodity pricing power. The Base case assumes West White Rose and ongoing drilling modestly grow production while price and margin normalize. Bear combines decline, project delay, Libya disruption and weaker price; Bull requires successful execution across all of those dimensions. The five-year outlook can be attractive without establishing a durable 20-year moat, and the missing E&P-specific reserve and capital disclosures should remain visible in synthesis rather than being replaced by false precision.

Appendix S - Synthesis (Combined Earnings Model)

Suncor Energy Inc. â€” Synthesis (Combined Earnings Model)

This appendix mechanically consolidates the three DR-cleared and peer-reviewed operating-segment forecasts into statutory operating income, pretax income, net income, and listed-unit EPS. It does not select a security-return valuation method, choose an exit multiple, calculate an IRR, score the company, or change any reviewed segment forecast. All currency amounts are Canadian dollars. Unless otherwise stated, income-statement and balance-sheet amounts are billions and share counts are millions.

1. Anchors and gate state

- Today and Stage-0 date: **2026-09-06**.
- Fiscal year end: **December 31**.
- Latest completed fiscal year used only for historical tie-out: **FY2025**, year ended 2025-12-31.
- TTM anchor: **2026-06-30**, comprising **Q3 2025 + Q4 2025 + Q1 2026 + Q2 2026**.
- Horizon: **2031-06-30**, exactly 5.0 calendar years after the TTM end. No forecast line compounds from FY2025 or for six fiscal years.
- Valuation anchor: **C$93.14 per XTSE:SU common share**, raw exchange close for the 2026-09-04 session. Raw quote-source SHA-256: `b4d8c761f4fd02e0dbe3f29e3be07a46a1ebbdaa55b3698df7dc01c021f85790`. QFR-sealed packet SHA-256: `694c23701637f13abfeb5da64d081846ebc80dc7a89b33bc53e4e287bdb4e3ea`. Actionability expiry: `2026-09-07T22:16:48+08:00`.
- The quote validator was rerun at `2026-09-07T00:04:13+08:00` with the expected packet hash and returned `QUOTE_PACKET_VALID`. The packet was unexpired at validation.
- Reporting and quote currency are both CAD. The listed security is the common share, not an ADR. Depositary ratio = 1.0, share-class factor = 1.0, and financial shares per listed unit = 1.0. FX, quote currency per reporting currency, = 1.0 as of 2026-09-04.
- The financial-statement diluted-share anchor of 1,179.0 million at 2026-06-30 multiplied by the no-intervening-split factor of 1.0 equals 1,179.0 million quote-basis financial shares. Dividing by the 1.0 listed-unit factor equals 1,179.0 million listed-unit equivalents.
- Statutory bridge SHA-256: `fab6c20af72b9ac32c4bba687af9a32c3b9f0a764fd222ae134805fcc315ac88`. The validator rerun returned `STATUTORY_BRIDGE_VALID` with exact hash equality. `gate_manifest.json` records both durable DR tokens, including `STATUTORY BRIDGE VERIFIED â€" CLEARED FOR FORECASTING` and `DATA PACKAGE VERIFIED â€" CLEARED FOR WAVE 2`.
- Reviewed artifact hashes were independently recomputed and matched the durable records: Oil Sands `eb3cc0f71e52434ccca9830ed6052695096ac7dcb3379de0d29f46925c4855af`; Exploration and Production `b7c89b29f9ba8b5e38e0f3085df2e93856093ea09c7c9cb28a6af08dc2893477`; Refining and Marketing `f4850e8816b88c919e466a3e7a7f5eb0d0e40da00fddd5385f8bc37171dd068b`; management `e78abf1fa226fb5a157505c48c852c2f81e266ed76ab008a619ef53bd05fae51`; and moat `5568dd0134d9ef5329344d3975a96f7db4a58808931bb16004a20661e5921b53`.

The exact common operating-segment profit basis is `Earnings (loss) before income taxes`. This label is preserved throughout. It is not renamed operating income. `Corporate and Eliminations` remains an explicit bridge line and is not treated as a fourth modeled operating segment.

2. Segment-level forward assumptions reproduced from reviewed appendices

Every terminal segment amount below is reproduced from the post-review appendix rather than recalculated or normalized by synthesis. Oil Sands controls at the total-segment level because no product-level TTM revenue/profit perimeter is disclosed. E&P uses one combined crude/NGL/gas line. R&M uses product allocations for transparency, while synthesis consumes only the reviewed segment total.

Segment	Exact profit metric	TTM revenue	Bear revenue / margin / profit	Base revenue / margin / profit	Bull revenue / margin / profit	Reviewed source
Oil Sands	Earnings (loss) before income taxes	C$20.888B	C$16.507B / 16.2113% / C$2.676B	C$23.671B / 29.7157% / C$7.034B	C$29.537B / 40.1700% / C$11.865B	`appendix_B_oil_sands.md Â§Â§8-10`
Exploration and Production	Earnings (loss) before income taxes	C$3.223B	C$2.172B / 6.0% / C$0.130B	C$3.587B / 29.0% / C$1.040B	C$4.626B / 44.0% / C$2.035B	`appendix_B_exploration_and_production.md Â§Â§8-10`
Refining and Marketing	Earnings (loss) before income taxes	C$36.617B	C$30.977B / 6.47% / C$2.004B	C$36.553B / 10.20% / C$3.730B	C$41.186B / 14.00% / C$5.767B	`appendix_B_refining_and_marketing.md Â§Â§8-10`

The segment economics are deliberately different. Oil Sands Base assumes moderate brownfield volume growth and lower unit cost but a margin below the TTM spike. E&P Base assumes West White Rose and development drilling offset decline, while its margin also normalizes below TTM. R&M Base is nearly flat in nominal revenue: diesel yield, exports, and channel optimization offset gasoline erosion and a lower through-cycle crack environment. No integration â€œsynergyâ€■ is added in consolidation because both upstream realization benefits and downstream channel economics already sit inside the reviewed segment margins.

The original segment probabilities are Oil Sands 25% Bear / 55% Base / 20% Bull, E&P 30% / 50% / 20%, and R&M 30% / 50% / 20%. For consolidated reporting, this appendix uses **28% Bear / 52% Base / 20% Bull**. These are probabilities for three joint macro-execution states, not averages applied independently to each segment. Bull stays at 20% because all three reviewers assigned the same weight and the joint case requires high commodity realization plus strong execution. Of the remaining 80%, Base receives 52% because the largest segment, Oil Sands, has the most concrete brownfield and cost program and carried a 55% Base prior. Bear receives 28% because E&P and R&M each carried a 30% downside prior and the company-wide moat/2046 gate failed, while Oil Sandsâ€™ scale and current balance sheet keep the joint downside below 30%. The probabilities therefore preserve the reviewed asymmetry without using uniform 33/33/34 weights or casually averaging terminal outputs.

3. Combined revenue build

The corporate revenue line is fixed at C$0.001B in all cases because both FY2025 and TTM disclosed C$0.001B for Corporate and Eliminations revenue. It is a sourced consolidation line, not a residual chosen to force the total. The operating-segment sum is otherwise the consolidated forecast.

Line	Bear	Base	Bull
Oil Sands horizon revenue	16.507	23.671	29.537
E&P horizon revenue	2.172	3.587	4.626
R&M horizon revenue	30.977	36.553	41.186
Sum of operating-segment horizon revenue	49.656	63.811	75.349
Corporate and Eliminations revenue	0.001	0.001	0.001
Combined horizon revenue	**49.657**	**63.812**	**75.350**
TTM to horizon CAGR over exactly five years	(3.9457)%	0.9953%	4.4089%

Arithmetic is direct: Bear `16.507 + 2.172 + 30.977 + 0.001 = 49.657`; Base `23.671 + 3.587 + 36.553 + 0.001 = 63.812`; Bull `29.537 + 4.626 + 41.186 + 0.001 = 75.350`. The CAGRs use the consolidated TTM revenue of C$60.729B and exactly five annual compounding intervals.

4. Combined statutory operating-income build

The forecast-driver ledger contains three relevant bridge families: Corporate and Eliminations, the mechanical reversal of financing expense required to reach statutory operating income before financing, and the opposite-sign financing line below operating income. Each is projected separately. The financing reversal never creates pretax earnings: it is added above the statutory operating-income subtotal and removed below it.

Horizon bridge line and explicit rule	Bear	Base	Bull
Sum of segment profit on exact sealed metric	4.810	11.804	19.667

Horizon bridge line and explicit rule	Bear	Base	Bull
Corporate and Eliminations	(1.700)	(1.100)	(0.800)
Consolidated segment-profit metric	3.110	10.704	18.867
Reverse financing expense to reach operating income	1.800	1.350	1.100
Combined statutory operating income	**4.910**	**12.054**	**19.967**
Combined operating-income margin	9.8878%	18.8899%	26.4990%

Corporate and Eliminations is anchored to a C$1.509B TTM loss and C$0.677B FY2025 loss. Bear holds the recent burden and allows central, FX, environmental, and project-support costs to rise to C$1.700B. Base gradually normalizes the loss to C$1.100B, giving partial credit to managementâ€™s enterprise-breakeven and cost program without assigning the full C$2B incremental free-funds-flow aspiration to this one line. Bull reaches C$0.800B through stronger utilization and cost absorption. These amounts are explicit assumptions; none is the difference between a desired consolidated result and segment profit.

Financing expense is anchored to C$1.636B TTM. Its scenario path is tied directionally to the Q2 2026 debt and lease anchors, not derived as a residual. At the horizon, Bear C$1.800B on C$16.700B of gross debt plus leases implies a 10.78% all-in burden; Base C$1.350B on C$13.600B implies 9.93%; Bull C$1.100B on C$11.700B implies 9.40%. These broad ratios include the mixed items historically presented in financing expense and are not asserted to be coupon rates. The operating reversal is exactly equal and opposite in every year and case.

Driver cadence	TTM 2026-06-30	2027-06-30	2028-06-30	2029-06-30	2030-06-30	2031-06-30
Bear Corporate and Eliminations	(1.509)	(1.550)	(1.580)	(1.620)	(1.660)	(1.700)
Base Corporate and Eliminations	(1.509)	(1.400)	(1.300)	(1.220)	(1.160)	(1.100)
Bull Corporate and Eliminations	(1.509)	(1.350)	(1.200)	(1.050)	(0.920)	(0.800)
Bear financing expense	(1.636)	(1.700)	(1.750)	(1.780)	(1.790)	(1.800)
Base financing expense	(1.636)	(1.550)	(1.480)	(1.420)	(1.380)	(1.350)
Bull financing expense	(1.636)	(1.500)	(1.400)	(1.300)	(1.200)	(1.100)
Operating reversal in each case	+opposite of financing expense	+opposite	+opposite	+opposite	+opposite	+opposite
Other non-operating income / expense	0.000	0.000	0.000	0.000	0.000	0.000

The zero other-income line is not a plug. The sealed latest-FY and TTM bridge contains no separate other-income line between statutory operating income and pretax income; financing expense is the only below-line item. Synthesis therefore carries zero rather than inventing a recurring gain or loss.

5. Net income and listed-unit EPS build

The tax schedule is anchored to the verified 25.54% FY2025 and 25.79% TTM effective statutory rates. Base uses 25.75%. Bear uses 24.00% because lower taxable resource profits and mix reduce the effective rate, while Bull uses 27.00% to recognize higher taxable resource rent and mix. Segment royalties already affect segment profit and are not deducted again.

Line	Bear	Base	Bull
Combined statutory operating income	4.910	12.054	19.967
Financing expense	(1.800)	(1.350)	(1.100)
Other income / expense	0.000	0.000	0.000
Pretax income	3.110	10.704	18.867
Effective tax rate	24.00%	25.75%	27.00%
Income tax expense	(0.746400)	(2.756280)	(5.094090)
Net income	**2.363600**	**7.947720**	**13.772910**
Quote-basis diluted financial shares at horizon	1,157.592089	1,015.463209	982.986435

Line	Bear	Base	Bull
Reporting-currency EPS per quote-basis share	2.041825	7.826694	14.011292
Financial shares per listed unit	1.0	1.0	1.0
Reporting-currency EPS per listed unit	2.041825	7.826694	14.011292
FX, quote currency per reporting currency	1.0	1.0	1.0
Quote-currency EPS per listed unit	**C$2.041825**	**C$7.826694**	**C$14.011292**

The required bridge is reproduced exactly. Bear: `C$2.363600B Ã- 1,000 / 1,157.592089M = C$2.041825` per quote-basis financial share; multiplying by 1.0 financial shares per listed unit and 1.0 CAD/CAD FX produces C$2.041825 per XTSE:SU common share. Base: `7.947720 Ã- 1,000 / 1,015.463209 = 7.826694`; applying both unit factors of 1.0 leaves C$7.826694. Bull: `13.772910 Ã- 1,000 / 982.986435 = 14.011292`; applying both unit factors produces C$14.011292.

5a. Return-method input bridge for later VP/CS work

This subsection supplies method-compatible operating and capital-structure inputs only. It does not select P/E, EV/NOPAT, or P/B-ROE; does not choose a multiple; and does not calculate security returns.

Input at 2031-06-30	Bear	Base	Bull	Source-bound path or explicit availability finding
Statutory operating income	4.910	12.054	19.967	Section 4 mechanical bridge from reviewed segment profit
Normalized cash tax rate	24.00%	25.75%	27.00%	TTM/FY statutory tax-rate anchor; scenario mix rule in Section 5
Normalized NOPAT	3.731600	8.950095	14.575910	Operating income Ã- one minus normalized cash tax rate
Cash	3.500	4.500	6.000	Q2 2026 anchor C$5.372B from `data_package.md` Â§8; explicit liquidity paths below
Gross debt excluding leases	10.500	8.000	6.500	Q2 2026 anchor C$9.853B from `data_package.md` Â§8; explicit debt paths below
Lease liabilities	6.200	5.600	5.200	Q2 2026 anchor C$4.827B from `data_package.md` Â§8; explicit lease paths below
Preferred equity	Unavailable	Unavailable	Unavailable	DR-cleared ledger provides no source-bound preferred-claim balance or terminal path
Minority interest / NCI claim	Unavailable	Unavailable	Unavailable	DR-cleared ledger provides no source-bound NCI balance or terminal path
Other senior claims	Unavailable	Unavailable	Unavailable	No complete source-bound claim inventory in the DR-cleared ledger
Separately valued non-operating assets	Unavailable	Unavailable	Unavailable	Current short-term investments are disclosed as zero; no separate terminal asset value is source-bound
Diluted listed-equivalent shares, M	1,157.592089	1,015.463209	982.986435	Section 6; quote-basis shares divided by the sealed 1.0 listed-unit factor

The explicit terminal balance-sheet paths are not residual net-debt targets. Bear cash moves from C$5.372B to C$4.500B, C$4.000B, C$3.800B, C$3.600B, and C$3.500B as cash is used to absorb weaker operating conditions. Bear debt moves to C$10.000B, C$10.200B, C$10.300B, C$10.400B, and C$10.500B. Base cash moves to C$5.000B, C$4.800B, C$4.600B, C$4.500B, and C$4.500B as excess liquidity is distributed; debt declines to C$9.500B, C$9.100B, C$8.700B, C$8.300B, and C$8.000B. Bull cash moves to C$5.500B, C$5.700B, C$5.900B, C$6.000B, and C$6.000B; debt declines to C$9.200B, C$8.500B, C$7.800B, C$7.100B, and C$6.500B. Lease liabilities rise in Bear to C$5.100B, C$5.350B, C$5.650B, C$5.950B,

and C$6.200B; in Base to C$5.000B, C$5.150B, C$5.300B, C$5.450B, and C$5.600B; and in Bull to C$4.950B, C$5.000B, C$5.050B, C$5.100B, and C$5.200B.

Because preferred equity, minority interest, other senior claims, and separately valued non-operating assets are not completely source-bound upstream, synthesis does not declare the EV-to-equity claim perimeter complete. VP must treat those explicit unavailability findings when determining whether EV/NOPAT is suitable. They do not impair the reconciled statutory EPS bridge.

5b. P&C insurer lane

NOT TRIGGERED â€” issuer is not a P&C insurer or reinsurer. No `insurer_return_bridge.json` is created.

6. Explicit five-year share-count, buyback, SBC, and distribution paths

All paths begin with the quote packetâ€™s 1,179.0 million quote-basis financial shares, not the 1,195.5 million TTM weighted-average denominator. Repurchase cash is anchored to C$3.456B TTM and the latest management cadence of C$500M per month, but no case assumes that cadence is guaranteed. SBC expense is anchored to C$0.650B TTM. Shares issued are approximated as annual SBC expense divided by the assumed average repurchase/share price, as required; this is disclosed approximation, not an assertion that all accounting SBC settles one-for-one in shares. Because CAD is both reporting and quote currency, no transaction-period FX conversion is required.

Case / year	Starting shares	Buyback cash	Average price	Shares retired	SBC expense	SBC issuance	Ending shares
Bear 2027	1,179.000000	1.500	85	17.647059	0.650	7.647059	1,169.000000
Bear 2028	1,169.000000	1.250	80	15.625000	0.650	8.125000	1,161.500000
Bear 2029	1,161.500000	1.000	78	12.820513	0.650	8.333333	1,157.012821
Bear 2030	1,157.012821	0.750	80	9.375000	0.650	8.125000	1,155.762821
Bear 2031	1,155.762821	0.500	82	6.097561	0.650	7.926829	1,157.592089
Base 2027	1,179.000000	4.000	100	40.000000	0.650	6.500000	1,145.500000
Base 2028	1,145.500000	4.200	107	39.252336	0.663	6.196262	1,112.443925
Base 2029	1,112.443925	4.400	114	38.596491	0.676	5.929825	1,079.777259
Base 2030	1,079.777259	4.600	121	38.016529	0.690	5.702479	1,047.463209
Base 2031	1,047.463209	4.800	128	37.500000	0.704	5.500000	1,015.463209
Bull 2027	1,179.000000	5.000	110	45.454545	0.650	5.909091	1,139.454545
Bull 2028	1,139.454545	5.500	122	45.081967	0.663	5.434426	1,099.807004
Bull 2029	1,099.807004	6.000	135	44.444444	0.676	5.007407	1,060.369967
Bull 2030	1,060.369967	6.500	149	43.624161	0.690	4.630872	1,021.376679
Bull 2031	1,021.376679	7.000	164	42.682927	0.704	4.292683	982.986435

Bear cumulative repurchases are C$5.000B and retire 61.565133 million shares; estimated SBC issues 40.157221 million, so `1,179.000000 - 61.565133 + 40.157221 = 1,157.592089`. Base cumulative repurchases are C$22.000B and retire 193.365357 million shares; estimated SBC issues 29.828566 million, so `1,179.000000 - 193.365357 + 29.828566 = 1,015.463209`. Bull cumulative repurchases are C$30.000B and retire 221.288045 million shares; estimated SBC issues 25.274480 million, so `1,179.000000 - 221.288045 + 25.274480 = 982.986435`.

Distributions are preserved separately for later return work and are not deducted from terminal EPS. Annual common dividends use each yearâ€™s average of starting and ending shares to calculate per-share cash.

Case	Annual dividends, 2027-2031	Cumulative dividends	Cumulative dividends per listed unit	Cumulative buybacks	Treatment
Bear	2.700 / 2.650 / 2.600 / 2.500 / 2.400	12.850	11.053650	5.000	Separate distribution input; not added to earnings
Base	2.900 / 3.000 / 3.100 / 3.200 / 3.300	15.500	14.188558	22.000	Separate distribution input; not added to earnings
Bull	3.000 / 3.200 / 3.400 / 3.600 / 3.800	17.000	15.844268	30.000	Separate distribution input; not added to earnings

The base annual buyback average is C$4.4B, above the C$3.456B TTM cash outflow but below managementâ€™s latest C$6B annualized cadence. The bull path requires sustained free cash generation and reaches the current stated cadence in

2029 before exceeding it. The bear path cuts repurchases aggressively while maintaining a gradually lower dividend. This explicit divergence prevents buybacks from functioning as an automatic EPS plug.

Capital consistency is bounded by managementâ€™s stated less-than-C$6B annual company-wide capex framework. The Oil Sands appendixâ€™s horizon diagnostic is C$4.4B Bear, C$4.0B Base, and C$4.7B Bull. That leaves C$1.6B, C$2.0B, and C$1.3B respectively inside a C$6B envelope for E&P, R&M, and corporate needs. The reviewed E&P and R&M appendices do not provide CAD capex allocations, so this synthesis does not invent them or assert that the remaining envelope is sufficient. The cash/debt and buyback paths are therefore explicit scenario assumptions for later valuation preflight, not a hidden free-cash-flow reconciliation.

7. Binary P/E 15 entry-price test

Required EPS at the sealed C$93.14 common-share price is `93.14 / 15 = C$6.209333` per listed unit. The P/E 15 entry-price gate is separate from later exit-method selection and is controlled by the Base case.

Case	Horizon EPS per listed unit	EPS Ã- 15	Sealed price	Cushion	Pass?
Bear	C$2.041825	C$30.627369	C$93.14	(67.1168)%	FAIL
Base	C$7.826694	C$117.400413	C$93.14	26.0473%	PASS
Bull	C$14.011292	C$210.169380	C$93.14	125.6489%	PASS

The binary result is **PASS**, with a **26.0473% Base-case cushion**. The result does not override the Management YELLOW, Moat FAIL, or 2046 FAIL gates and is not itself a trade recommendation. The Bear caseâ€™s failure shows that the entry-price conclusion remains highly sensitive to the commodity and operating state.

8. Reflexivity, interim-period, and recency checks

The TTM anchor ties without a plug. Segment revenue is `20.888 + 3.223 + 36.617 = 60.728`; adding the disclosed C$0.001B Corporate and Eliminations revenue yields C$60.729B, equal to consolidated TTM revenue. Segment profit is `6.965 + 1.050 + 5.523 = 13.538`; Corporate and Eliminations of C$(1.509)B reaches pretax/segment-metric C$12.029B; adding the C$1.636B financing reversal reaches C$13.665B statutory operating income; subtracting C$1.636B financing expense returns C$12.029B pretax; subtracting C$3.102B tax reaches C$8.927B net income. All residuals are zero.

The FY2025 sanity check also ties: `19.298 + 2.509 + 30.569 + 0.001 = 52.377` revenue; `5.277 + 0.526 + 2.822 = 8.625` segment profit; `8.625 - 0.677 = 7.948` pretax; `7.948 + 1.080 = 9.028` statutory operating income; `9.028 - 1.080 = 7.948` pretax; and `7.948 - 2.030 = 5.918` net income.

The latest interim bridge is **NOT TRIGGERED â€" four non-overlapping quarters used**: Q3 2025, Q4 2025, Q1 2026, and Q2 2026. Q4 values were derived where necessary as FY2025 less the official nine-month period, after which the four standalone quarter values were summed. No cumulative H1 or nine-month period overlaps a standalone quarter in the TTM.

First-forward-year combined revenue stays within 10% of the C$60.729B TTM run rate in all cases. Bear uses Oil Sands C$19.927424B, E&P C$2.978B, R&M C$35.396B, and corporate revenue C$0.001B, totaling C$58.302424B, 3.9957% below TTM. Base totals `21.417114 + 3.293 + 36.584 + 0.001 = 61.295114`, 0.9322% above TTM. Bull totals `22.386735 + 3.465 + 37.468 + 0.001 = 63.320735`, 4.2677% above TTM. The model therefore does not convert Q2 2026â€™s unusually strong comparison into an unsupported first-year step change.

9. Sensitivity: which variables matter most

Sensitivity holds every unvaried Base input constant. Oil Sands is Segment 1 and E&P is Segment 2. The exact Base segment-profit metric, Corporate and Eliminations, tax, financing classification, and share path remain unchanged except for the named variable.

Variable change around Base	Low-case horizon EPS	Base EPS	High-case horizon EPS	EPS change versus Base
Oil Sands revenue CAGR Â±200 bps	7.344280 at 0.5331% CAGR	7.826694	8.348275 at 4.5331% CAGR	(0.482414) / +0.521581
E&P exact profit margin Â±200 bps	7.774407 at 27.0%	7.826694	7.879318 at 31.0%	(0.052288) / +0.052624
Horizon diluted shares Â±5%	8.238625 at 95% of Base shares	7.826694	7.453994 at 105%	+0.411931 / (0.372700)
Tax rate Â±300 bps	8.142924 at 22.75%	7.826694	7.510464 at 28.75%	+0.316230 / (0.316230)

The dominant local driver is Oil Sands revenue growth, followed by the share-count path. E&P margin is much less influential because the segment is small. The P/E 15 cushion is therefore primarily exposed to Oil Sands production/realization and whether free cash generation actually supports the modeled net share retirement.

10. Combined earnings summary

Probability-weighted figures are diagnostics calculated from the three discrete outcomes, not a fourth scenario. Weighted EPS is the sum of scenario EPS times probability, not weighted net income divided by weighted shares.

Case	Revenue	Statutory OI	OI margin	Net income	EPS per listed unit	Probability	EPS Ã- 15	Versus C$93.14
Bear	C$49.657B	C$4.910B	9.8878%	C$2.363600B	C$2.041825	28%	C$30.627369	(67.1168)%
Base	C$63.812B	C$12.054B	18.8899%	C$7.947720B	C$7.826694	52%	C$117.400413	26.0473%
Bull	C$75.350B	C$19.967B	26.4990%	C$13.772910B	C$14.011292	20%	C$210.169380	125.6489%
Probability weighted	C$62.156200B	C$11.636280B	n/m	C$7.549204B	C$7.443850	100%	C$111.657754	19.8816%

The Base case is a modest-revenue-growth, lower-share-count outcome rather than an aggressive top-line thesis. Revenue grows just 0.9953% annually, while Oil Sands normalization and R&M cycle normalization keep profitability below the strongest recent quarter. The EPS result depends materially on retiring 163.536791 million net shares over five years. If buybacks weaken, EPS loses some of its cushion even when business-level pretax income holds.

The Bear case preserves positive earnings but fails the entry-price test decisively. It combines weaker commodity realization, E&P project/geopolitical setbacks, soft refining cracks, a higher corporate burden, and lower repurchase capacity. The Bull case requires favorable commodity, differential, reliability, and downstream-capture assumptions simultaneously, which is why its 20% probability is not raised despite the large EPS output.

11. Mandatory arithmetic tie-out checks

Check 1 â€” Reported-financial and statutory-bridge tie-out: PASS

TTM revenue: `20.888 + 3.223 + 36.617 + 0.001 = 60.729`, exactly the consolidated source. TTM profit: `6.965 + 1.050 + 5.523 - 1.509 = 12.029`; `12.029 + 1.636 = 13.665` statutory OI; `13.665 - 1.636 = 12.029` pretax; `12.029 - 3.102 = 8.927` NI. FY2025 revenue: `19.298 + 2.509 + 30.569 + 0.001 = 52.377`. FY2025 profit: `5.277 + 0.526 + 2.822 - 0.677 = 7.948`; `7.948 + 1.080 = 9.028` OI; `9.028 - 1.080 - 2.030 = 5.918` NI. All bridge residuals are zero, within the C$1M packet tolerance and the 2% reflexivity threshold. Sources: `statutory_bridge.json`; `data_package.md` Â§Â§2, 3, 3a.

Check 2 â€” NI / shares / listed-unit / FX equals EPS: PASS

Bear `2.363600 Ã- 1,000 / 1,157.592089 Ã- 1.0 Ã- 1.0 = C$2.041825`. Base `7.947720 Ã- 1,000 / 1,015.463209 Ã- 1.0 Ã- 1.0 = C$7.826694`. Bull `13.772910 Ã- 1,000 / 982.986435 Ã- 1.0 Ã- 1.0 = C$14.011292`. Source: Section 5 and QFR-sealed `quote_packet.json`.

Check 3 â€” Segment sum at horizon: PASS

Bear segment revenue is C$49.656B and combined revenue is C$49.657B after the named C$0.001B corporate line; `49.657 / 49.656 = 100.0020%`. Base `63.812 / 63.811 = 100.0016%`. Bull `75.350 / 75.349 = 100.0013%`. Each is within 1%, and the only gap is the disclosed Corporate and Eliminations revenue line. Source: Section 3.

Check 4 â€” Product-to-segment rollup: PASS

R&M Bear `12.201 + 16.064 + 2.711 = 30.976B`, versus C$30.977B displayed segment revenue; the C$0.001B difference is rounding. Base `14.254 + 19.145 + 3.154 = 36.553B`, exact. Bull `16.167 + 21.622 + 3.397 = 41.186B`, exact. E&P has one combined crude/NGL/gas revenue line, so product sum equals segment revenue at C$2.172B / C$3.587B / C$4.626B with zero residual. Oil Sands does not model product revenues because a compatible TTM product perimeter is unavailable; its reviewed total-segment control is C$16.507B / C$23.671B / C$29.537B with no additive product line. Sources: all three reviewed appendices Â§10.

Check 5 â€” Weighted margin: PASS

R&M is the only segment with more than one modeled product. Bear product profit is `12.201Ã-5.0% + 16.064Ã-8.0% + 2.711Ã-4.0% = 2.003610B`; divided by C$30.976B gives 6.4683%, reconciling to the reviewed 6.47% and C$2.004B after rounding. Base `14.254Ã-8.5% + 19.145Ã-12.0% + 3.154Ã-7.0% = 3.729770B`; divided by C$36.553B gives 10.2033%, reconciling to 10.20% and C$3.730B. Bull `16.167Ã-11.5% + 21.622Ã-16.5% + 3.397Ã-10.0% = 5.766535B`; divided by C$41.186B gives 14.0000%, reconciling to 14.00% and C$5.767B. Oil Sands and E&P have no multi-product exact-profit allocation. Source: reviewed R&M Â§Â§9-10.

Check 6 â€” Share count and security-unit path: PASS

`1,179.0 financial-statement diluted shares Ã- 1.0 split factor = 1,179.0 quote-basis financial shares`; `1,179.0 / (1.0 depositary ratio Ã- 1.0 share-class factor) = 1,179.0 listed-unit equivalents`. Bear `1,179.000000 - 61.565133 + 40.157221 = 1,157.592089`; Base `1,179.000000 - 193.365357 + 29.828566 = 1,015.463209`; Bull `1,179.000000 - 221.288045 + 25.274480 = 982.986435`. Each path contains exactly five annual buyback/SBC steps. Source: `quote_packet.json`, `quant_foundation.md` P6, and Section 6.

Check 7 â€” Growth plausibility: PASS

Oil Sands Base 2.5331% is slightly above 1.2 times its 1.9% FY2023-FY2025 segment CAGR, but the reviewed appendix explicitly supports the difference with the 100,000 bbls/d upstream commitment allocation, Fort Hills ramp, in-situ pads, debottlenecking, and a margin below TTM. E&P Base 2.17% exceeds its negative current-perimeter revenue history but is explicitly tied to West White Rose nearing completion, Hebron/Hibernia development drilling, and a run-rate rising only to 80 mboe/d; it does not extrapolate Q2â€™s 72.5% comparison. R&M gasoline Base is negative 2.0%; distillateâ€™s positive 1.5% is explicitly tied to the disclosed 16 mbbls/d yield project with only 12 mbbls/d sustained; Otherâ€™s 0.5% is modest. The reviewed appendices contain the required quantified mechanisms rather than unsupported extrapolation.

Check 8 â€” Historical arithmetic of every forward revenue row: PASS

Oil Sands: `20.888Ã-(1-4.5987%)^5 = 16.507007`, `20.888Ã-(1+2.5331%)^5 = 23.671038`, and `20.888Ã-(1+7.1751%)^5 = 29.536997`, reproducing C$16.507B / C$23.671B / C$29.537B. E&P: `3.223Ã-(1-7.59%)^5 = 2.171977`, `3.223Ã-(1+2.17%)^5 = 3.588205`, and `3.223Ã-(1+7.49%)^5 = 4.624882`, each within 0.04% of the reviewed displayed C$2.172B / C$3.587B / C$4.626B. R&M Bear product rows recompute to C$12.201752B, C$16.064480B, and C$2.711131B; Base to C$14.253927B, C$19.145491B, and C$3.154698B; Bull to C$16.167187B, C$21.622355B, and C$3.397257B. Every difference is below 0.03%, comfortably inside 1%. Sources: reviewed appendix Â§8 tables.

Check 9 â€” Recency anchor: PASS

First-forward-year revenue versus C$60.729B TTM is C$58.302424B Bear, down 3.9957%; C$61.295114B Base, up 0.9322%; and C$63.320735B Bull, up 4.2677%. All are inside Â±10%. Each value is the sum of the reviewed first-year segment cadence plus C$0.001B corporate revenue. Source: Section 8 and segment Â§8 cadence tables.

Check 10 â€” Period and horizon integrity: PASS

The TTM uses four non-overlapping quarters: Q3 2025 + Q4 2025 + Q1 2026 + Q2 2026. No cumulative YTD bridge is combined with overlapping standalone quarters. Every terminal CAGR runs from 2026-06-30 to 2031-06-30 for exactly five years. FY2025 is used only for historical tie-out, never as the forecast base. Source: Stage-0 anchors, `quant_foundation.md` P4, and Sections 1 and 8.

Check 11 â€” Valuation, unit bridge, hashes, and probability arithmetic: PASS

Exact SHA-256 recomputation matched `694c23701637f13abfeb5da64d081846ebc80dc7a89b33bc53e4e287bdb4e3ea` for `quote_packet.json` and `fab6c20af72b9ac32c4bba687af9a32c3b9f0a764fd222ae134805fcc315ac88` for `statutory_bridge.json`. Listing XTSE:SU, C$93.14 raw close, 1.0 split, 1.0 depositary ratio, 1.0 share-class factor, 1.0 financial share per listed unit, and 1.0 CAD/CAD FX all reproduce. EPS Ã- 15 equals C$30.627369 / C$117.400413 / C$210.169380. Probabilities `28% + 52% + 20% = 100%`. Probability-weighted EPS is `2.041825Ã-0.28 + 7.826694Ã-0.52 + 14.011292Ã-0.20 = C$7.443850`; multiplying by 15 gives C$111.657754. Cushion is `(117.400413 - 93.14) / 93.14 = 26.0473%`, and Base controls the binary PASS.

Synthesis gate conclusion

All eleven checks pass with visible arithmetic and no plugs. The mechanical Base outcome at the exact five-year horizon is C$63.812B revenue, C$12.054B statutory operating income, C$7.947720B net income, and C$7.826694 EPS per XTSE:SU common share. Required EPS at 15 times and the sealed C$93.14 price is C$6.209333, leaving a 26.0473% cushion. Terminal capital-structure inputs are supplied where an explicit path can be anchored; preferred, NCI, other senior claims, and separately valued non-operating assets remain explicitly unavailable for later method selection. Distributions remain separate from earnings and terminal valuation.

SYNTHESIS CLEARED â€” 11/11 TIE-OUTS PASSED

Appendix CS - Compounder Score

Suncor Energy Inc. â€” Compounder Score

Security: XTSE:SU common share (SU.TO) **Analysis date:** 2026-09-07 **Current price:** CAD 93.14, 2026-09-04 close **TTM end / terminal date / exact underwriting horizon:** 2026-06-30 / 2031-06-30 / exactly 5.0 years **Reporting and return currency:** CAD; net-SGD overlay shown separately **Valuation preflight:** `C:/Users/Admin/OneDrive/GPT/ER 2.0/Suncor Energy Inc/valuation_preflight.json` **Valuation preflight SHA-256:** `3ff196132fb7f68906bba300d74c2b3db1ad6ec6f8354f444eec7a97a6afbd07` **Validator:** `VALUATION_PREFLIGHT_VALID`; all five foundations passed; blockers empty

1. Executive Verdict

Compounder Score: 45/100. Business Quality Score: 43/80. 20% Return Underwriting Score: 2/20. Score-implied classification: Reject.

The evidence supports a financially sound, integrated commodity producer with strong cash conversion, falling leverage, substantial share-count reduction and a credible recent operating reset. It does not support a high-ROIIC, durable 20-year compounder at the current price. Standardized ROIC had a five-observation median of 11.85% and was below 12% in four of FY2021-FY2025. A credible standard or acquisition-inclusive ROIIC cannot be calculated from the reviewed package because extractive depletion makes net capex negative, working-capital movements are volatile and deal-level returns are not disclosed. The Moat and 2046 gates both failed, while Management is YELLOW because the April 2027 CEO hand-off and permanent CFO solution remain unproven.

The locked P/E return model is decisive. It produces finite five-year gross CAD shareholder IRRs of **-17.52% Bear, -0.15% Base and 4.11% Bull**. Probability-weighted terminal wealth is CAD 80.817075 per share at weights of 28% / 52% / 20%, producing a **-2.80%** probability-weighted gross CAD CAGR. The same P/E method and scenario weights produce net-SGD returns of **-19.76% / -0.69% / 5.23%**, with a **-3.12%** probability-weighted net-SGD CAGR under the specified cost, withholding and FX convention. Returns are not suppressed by the Reject classification.

Confidence is **Medium**. The statutory bridge, price, shares, scenario EPS, distributions and exit multiples are hash-bound and arithmetic-complete. Confidence is capped by the commodity cycle, only five clean annual observations, unavailable credible ROIIC, undisclosed project-level returns, the failed long-duration moat evidence and management transition risk.

2. Data Source Map

All local source hashes were recomputed before scoring. The synthesis SHA-256 is `beb2f5acb31c1bfbb9299f8c6ea5bdd7006a8e4dee43a6ab4f75c5c4471f48ee`.

Evidence family	Source used	Period / currency	Use in this score
Price / market cap	`quote_packet.json`; archived FMP stable quote	2026-09-04; CAD	CAD 93.14 price; FMP market cap CAD 109.975055B
Enterprise value	FMP market cap plus `data_package.md` Q2 2026 cash, debt and leases	2026-06-30 balance sheet; CAD	CAD 119.283055B including leases; diagnostic only because P/E controls returns
Income statement	`quant_foundation.md`; `data_package.md`; `statutory_bridge.json`	FY2021-FY2025 and TTM 2026-06-30; CAD	Revenue, operating income, NOPAT, net income and statutory EPS
Balance sheet	`quant_foundation.md`; `data_package.md`; official Q2 2026 filing	2026-06-30; CAD	Cash CAD 5.372B, debt ex leases CAD 9.853B, leases CAD 4.827B
Cash flow	`quant_foundation.md`; `data_package.md`; official annual and interim filings	FY2021-TTM 2026-06-30; CAD	CFO, capex, FCF, dividends and repurchases
Share count	`quote_packet.json`; `quant_foundation.md`; `appendix_synthesis.md`	FY2021-2031 horizon; millions	Historical shrinkage and scenario repurchase/SBC dilution paths
SBC	`quant_foundation.md`; `appendix_management.md`; `appendix_synthesis.md`	FY2024, FY2025, TTM 2026; CAD	TTM expense CAD 0.650B; modeled issuance explicit

Evidence family	Source used	Period / currency	Use in this score
Segment data	Three reviewed `appendix_B_*.md` files; official segment notes	FY2021-TTM 2026 and 2031 scenarios; CAD	Oil Sands, E&P and R&M unit economics and runway
Management commentary	`appendix_management.md`; archived last eight calls; 2026 proxy and Investor Day	Through 2026-09-06	Operating record, incentives, succession, capital discipline
Capital allocation	`data_package.md`; `appendix_management.md`	FY2021-H1 2026; CAD	Capex, Fort Hills, debt reduction, dividends and buybacks
Compensation / governance	`appendix_management.md`; 2026 proxy	2025-2026	Incentive alignment, ownership, controls and board independence
TAM / demand / regulation	`appendix_moat.md`; IEA WEO/Oil/EV reports; CER 2026; Canada regulations	Current to 2046/2050	Oil-demand, refining, carbon, reserve-life and transition risks
Competitors	Segment appendices; CNRL, Cenovus and Imperial primary materials	FY2025-2026	Scale, asset quality, capital allocation and refining comparisons
Valuation method / exits	Validator-cleared `valuation_preflight.json`	Current and 2031; CAD	P/E locked; Bear/Base/Bull exits 12.0x / 10.0x / 7.0x

Source-bound files include `quant_foundation.md` SHA-256 `725d67d0634b4e344664abecd491848e6a10304dc4394a2ec023648556529d18`, `data_package.md` SHA-256 `841b967cfb20642a4d05774daa683618a97b3d1d9973143b5c89ce7ec82cf251`, management SHA-256 `e78abf1fa226fb5a157505c48c852c2f81e266ed76ab008a619ef53bd05fae51`, and moat SHA-256 `5568dd0134d9ef5329344d3975a96f7db4a58808931bb16004a20661e5921b53`.

3. Key Financial and Quality Metrics

For this asset-heavy producer, standard industrial ROIC is informative but incomplete. Depletion, sustaining capital, reserve replacement, environmental obligations and commodity marks complicate incremental-return measurement. The table therefore distinguishes calculated values from unavailable items. â€œFive observationsâ€■ means FY2021-FY2025 and four year-to-year compounding intervals.

Metric	1-year	3-year	Five observations	10-year	Basis / interpretation
Revenue CAGR	(3.51)%	(5.71)%	5.73%	n/a	FMP post-royalty revenue; 3-year is FY2022-2025
NOPAT CAGR	(10.33)%	(16.60)%	6.38%	n/a	Standardized analytical NOPAT from `data_package.md`
FCF CAGR	(26.93)%	(13.12)%	(1.00)%	n/a	CFO less capex
Standardized ROIC	9.95%	11.85% median	11.85% median	n/a	FY2021-FY2025 range 8.74%-19.21%
Standard / acquisition-inclusive ROIIC	n/m	Insufficient evidence	Insufficient evidence	n/a	Net-capex denominator is negative and deal-level returns are unavailable
Reinvestment rate	n/m	n/m	n/m	n/a	Prescribed net-capex-plus-WC measure is not economically stable here
FCF / NOPAT conversion	116.33%	118.19% aggregate	118.62% aggregate	n/a	Strong cash support for earnings
Operating margin	16.35%	17.68% median	17.68% median	n/a	FY2021-FY2025 range 16.06%-23.87%
Diluted share-count CAGR	(4.39)%	(4.26)%	(4.86)%	n/a	1,489M FY2021 to 1,220M FY2025
SBC / revenue	0.97%	n/a	n/a	n/a	FY2025 official SBC CAD 0.473B / revenue CAD 48.908B
SBC / FCF	6.83%	n/a	n/a	n/a	FY2025 official SBC / FCF CAD 6.925B
Net debt / EBITDA	0.91x	n/a	n/a	n/a	FY2025 standardized metric; issuer Q2 2026 net debt/AFFO was 0.3x
EV / TTM NOPAT	11.76x	n/a	n/a	n/a	Diagnostic only; P/E is the locked return method
TTM FCF yield	9.39%	n/a	n/a	n/a	CAD 10.327B / FMP quote market cap

Metric	1-year	3-year	Five observations	10-year	Basis / interpretation
TTM dividend-yield proxy	2.54%	n/a	n/a	n/a	Dividends paid / TTM weighted shares / current price
TTM net-buyback-yield proxy	3.14%	n/a	n/a	n/a	Repurchases / current market cap; average market cap unavailable

The five-year median standardized ROIC of 11.85% earns only 2/5 under the fixed rubric. It is not an accounting artifact: FY2025 invested capital was CAD 59.857B, so the denominator is neither tiny nor negative. However, the data do not support the >20% incremental-return profile the compounder test seeks.

4. Rubric Scorecard

Rubric item	Score	Maximum	Evidence-led judgment
1A. Normalized ROIC is high	2	5	Five-observation median 11.85%
1B. ROIIC is high	0	8	Credible standard and acquisition-inclusive ROIIC unavailable
1C. ROIIC is not deteriorating sharply	0	3	NOPAT fell sharply from the FY2022 cycle peak
1D. Unit economics support returns	2	3	Long-life integrated assets help cost/capture, but returns remain price-driven
1E. Cash conversion is real	3	3	FY2021-FY2025 aggregate FCF/NOPAT 118.62%
1F. ROIC is not an accounting artifact	2	3	Meaningful capital base; incomplete lease/R&D normalization caps credit
Category 1 â€” Incremental Returns on Capital	**9**	**25**	**Well below compounder standard**
2A. Large remaining market opportunity	3	5	Large liquid-fuel market and resource base, but mature/declining demand risk
2B. Proven ability to reinvest at scale	3	5	Operating improvement and brownfield projects; project-level returns not isolated
2C. Organic growth opportunity	3	4	Fort Hills, in-situ, debottlenecking, WWR and diesel yield projects
2D. Repeatable expansion playbook	2	3	Brownfield operating playbook credible but not fully cycle-tested under new team
2E. Market structure supports long growth	1	2	Refinery scarcity helps; global oil supply and demand cap economics
2F. Growth does not require ROIC collapse	0	1	Not proven across a commodity cycle
Category 2 â€” Reinvestment Runway	**12**	**20**	**Real five-year projects; weak 20-year proof**
3A. Clear source of advantage	3	4	Scale, installed infrastructure, integration and operating learning
3B. Pricing power	0	3	Upstream benchmarks and refining cracks set economics
3C. Competitive evidence	1	3	Asset utility and reliability, but peers own comparable scale/configuration
3D. Customer stickiness	0	2	No material upstream switching cost; fuel retail is competitive
3E. Resilience through stress	2	2	All segments stayed profitable across the clean five-year history
3F. Low disruption risk	0	1	Policy, carbon, demand transition and reserve replacement remain material
Category 3 â€” Durability of Moat	**6**	**15**	**Moat gate FAIL; 2046 test FAIL**
4A. Clean revenue and earnings quality	1	2	Audited bridge is clean; TTM is cycle/event-heavy and needs normalization

Rubric item	Score	Maximum	Evidence-led judgment
4B. Cash flow supports earnings	2	2	Strong multi-year FCF conversion
4C. Conservative SBC and dilution treatment	2	2	SBC expensed; modeled issuance explicit; net shares fell materially
4D. Balance sheet strength	2	2	Q2 2026 net debt ex leases CAD 4.481B; ample credit
4E. Transparent disclosures	1	1	Good operating and capital disclosure with named gaps
4F. No governance/accounting red flags	1	1	No identified restatement, related-party or controls problem
Category 4 â€" Accounting and Financial Quality	**9**	**10**	**Strongest part of the score**
5A. Reinvestment priority is rational	2	2	Sustain base, fund brownfield economics, then return excess cash
5B. Acquisition discipline	1	2	No serial empire building; Fort Hills deal return is not disclosed
5C. Buyback discipline	1	2	Material shrinkage, but cadence is capacity-led rather than valuation-led
5D. Incentives align with value creation	2	2	TSR/ROCE and cash gate provide real alignment
5E. Owner mentality	0	1	CEO had no actual common shares at proxy date; exposure is award-heavy
5F. Evidence from past decisions	1	1	Reliability, debt reduction and per-share shrinkage are observable
Category 5 â€" Capital Allocation	**7**	**10**	**Good recent evidence, incomplete cycle and succession proof**
6A. Base-case IRR at least 20%	0	6	Base gross CAD IRR is (0.15)%
6B. Conservative exit multiple	0	4	The Base 20% case needs 27.7989x, 44.8981% above normalized current P/E: major expansion
6C. Bear case is acceptable	0	3	Bear gross CAD IRR is (17.52)%
6D. Reverse-return hurdle is beatable	0	3	Required EPS CAD 21.757357 versus Base CAD 7.826694
6E. Multiple does not already price perfection	0	2	Normalized current P/E 19.19x versus 10.0x Base exit and near-zero Base return
6F. Cash returns help	2	2	CAD 11.05-CAD 15.84 distributions per share materially soften outcomes
Category 6 â€" Price and 20% Underwriting	**2**	**20**	**Major expansion required for the Base 20% case**
Business Quality Score	**43**	**80**	**Fails 65/80 investable threshold**
Compounder Score	**45**	**100**	**Score-implied Reject**

The ROIIC-plus-runway subtotal is **21/45**, below the required 35/45. The fixed denominators are retained; missing evidence earns zero rather than being removed from the denominator.

5. ROIIC and Reinvestment Analysis

The prescribed ROIIC denominator is cumulative net capex plus change in non-cash working capital, capitalized R&D/growth opex where justified, and acquisitions net of disposals. It is not economically stable for Suncor over the reviewed period. D&A/depletion exceeded capex in FY2023-FY2025, making net capex negative. Working-capital cash movements also reversed materially, and FMP's signed `acquisitionsNet` field is not gross deal consideration. A mechanical quotient could therefore print a high positive ROIIC from a falling NOPAT numerator divided by a negative reinvestment denominator. That would be economically false.

The evidence does show deterioration rather than compounding: standardized NOPAT fell from CAD 10.263B in FY2022 to CAD 5.953B in FY2025. A conservative gross-capex proxy over FY2023-FY2025 also produces a negative incremental return because NOPAT declined while the company spent CAD 18.167B of capex. This is not proof that each project destroys value; it is proof that consolidated commodity-cycle data cannot establish high ROIIC. Accordingly, standard and

acquisition-inclusive ROIIC are marked **Insufficient evidence** and score 0/8, with no denominator waiver.

Cash conversion is materially better. Aggregate FY2021-FY2025 FCF of CAD 40.687B divided by aggregate standardized NOPAT of CAD 34.301B equals 118.62%. TTM CFO of CAD 15.796B less capex of CAD 5.469B produced CAD 10.327B of FCF. Strong conversion supports accounting quality and shareholder distributions, but harvesting/depletion cash flow is not automatically high-return reinvestment.

6. Runway Analysis

There is a credible five-year project runway. Oil Sands has long-life, low-decline resources, Fort Hills throughput potential, in-situ pads, mine/debottlenecking work and a management commitment to more than 100,000 bbl/d of upstream growth. E&P has West White Rose near completion and Hebron/Hibernia drilling, though field-level reserves, decline rates and capital returns are incomplete. R&M has diesel-yield optimization, logistics/export channels, secondary-unit reliability and a scarce installed refinery footprint. Management targets these projects within less than CAD 6B of annual company-wide capital.

The evidence does not support a 20-year runway at high incremental returns. The approximate Oil Sands reserve life reaches roughly the 2046 test date; E&P is depleting and geopolitically exposed; gasoline demand faces efficiency and EV substitution; and carbon, water, tailings and reclamation requirements can absorb savings. The Base consolidated revenue CAGR is only 0.9953% from TTM to 2031. Most Base EPS support comes from margin normalization and a net reduction of 163.536791M shares, not broad organic revenue compounding.

7. Moat Analysis

Suncor's advantage can be explained in one paragraph: a large, permitted, hard-to-replicate system of long-life oil-sands assets, upgraders, refineries, pipelines, terminals, storage and retail channels, reinforced by operating know-how, can lower unit cost and route barrels toward better realizations than a standalone asset. The advantage is real, but it does not detach profits from WTI/WCS prices, crack spreads, utilization, royalties, carbon policy or local fuel competition. Peers such as CNRL, Cenovus and Imperial possess comparable scale or integration, customers face low switching costs, and Suncor has no verified ability to set commodity prices.

The reviewed moat conclusion is therefore controlling: **Moat gate FAIL; 2046 test FAIL.** The five-year record demonstrates survivability and asset utility, not a stable high-return franchise. AI is not the main disruption threat; demand transition, regulation, reserve replacement, maintenance execution and global marginal supply are.

8. Accounting and Capital Allocation Analysis

Accounting quality is high relative to the business model. The official statutory bridge reconciles segment pretax profit, Corporate and Eliminations, financing, tax and net income with zero residual. FMP classification differences are explicitly overridden by official filings rather than hidden. The TTM contains an unusually strong Q2 2026 commodity/refining environment, but the preflight normalizes it with FY2025 statutory EPS and scenario-specific margins. SBC is treated as an economic cost and issuance is modeled explicitly.

The balance sheet is a strength. At Q2 2026, cash was CAD 5.372B, debt excluding leases CAD 9.853B, lease liabilities CAD 4.827B and net debt excluding leases CAD 4.481B. Available credit was CAD 5.307B. The diluted share count fell from 1,489M in FY2021 to 1,220M in FY2025 while the company paid CAD 12.507B of dividends and spent CAD 15.709B on repurchases over FY2021-FY2025.

Capital allocation is good but not exemplary. Fort Hills consolidation improved operational control, yet disclosed data do not isolate the acquisition return. Buybacks created observable per-share shrinkage, but cadence follows cash/debt capacity rather than an explicit valuation hurdle. Incentives include TSR and ROCE, but CEO actual common-share ownership was zero at the proxy date. Management is **YELLOW**, not FAIL: the operating record and disclosure are strong, while succession and the future CFO structure remain unresolved.

9. 20% Return Underwriting

Locked denominator and valuation method

Primary valuation method: P/E. This reproduces the validator-cleared preflight exactly. EV/NOPAT is rejected because the terminal enterprise-to-equity claim perimeter is incomplete; P/B-ROE is secondary and lacks a zero-residual parent-common-equity roll-forward. No terminal cash, debt, lease or non-operating asset adjustment is added after EPS times

P/E.

Denominator / multiple	Value	Integrity conclusion
Reported current statutory diluted EPS	CAD 7.4671685487	TTM ended 2026-06-30; event-heavy
Reported current P/E	12.4732687353x	Disclosure row; not used to set exits
Normalized current statutory diluted EPS	CAD 4.8547990156	FY2025 through-cycle proxy locked by VP
Comparable normalized current P/E	19.1851402501x	Directly recomputed as 93.14 / 4.8547990156
Terminal denominator	2031 statutory diluted EPS	Same CAD/listed-common-share perimeter
Bear / Base / Bull exit P/E	12.0x / 10.0x / 7.0x	Reproduced exactly from VP

The exits were selected before returns. Bear 12.0x is near the low-earnings end of the FY2021-FY2025 6.58x-12.56x observed range; Base 10.0x is an interior through-cycle anchor; Bull 7.0x is tied to the 6.58x-6.71x peak-earnings observations to avoid double counting cycle-peak EPS. VP's excessive-optimism and excessive-bearishness tests both passed. The multiples are independently justified and not changed to make the score pass.

Gross CAD scenario returns

Case	Weight	Terminal EPS	Exit P/E	Terminal equity value / share	Cumulative distributions / share	Terminal shareholder wealth / share	Gross CAD IRR
Bear	28%	2.041825	12.0x	24.501900	11.053650	35.555550	(17.52)%
Base	52%	7.826694	10.0x	78.266940	14.188558	92.455498	(0.15)%
Bull	20%	14.011292	7.0x	98.079044	15.844268	113.923312	4.11%
Probability weighted	100%	n/a	n/a	n/a	n/a	80.817075	(2.80)%

The exact formula is `(terminal shareholder wealth / 93.14)^(1 / 5.0) - 1`. Probability-weighted wealth is `28% Ã- 35.555550 + 52% Ã- 92.455498 + 20% Ã- 113.923312 = CAD 80.81707536`; its five-year CAGR is -2.7984077155%. Scenario IRRs are not averaged.

Reverse-return hurdle and maximum price

At 20%, required terminal shareholder wealth is `93.14 Ã- 1.20^5 = CAD 231.7621248`. After Base distributions of CAD 14.188558, required terminal equity value is CAD 217.5735668. At the locked 10.0x Base exit P/E, required terminal EPS is **CAD 21.75735668**, implying **23.8483%** annual EPS growth from VP's current statutory diluted EPS of CAD 7.4671685487. Modeled Base terminal EPS is only CAD 7.826694.

Holding modeled Base EPS constant, the required exit P/E is 27.7989x, above the comparable normalized current 19.1851x. The 20% Base case therefore requires unsupported expansion and fails the hard veto. The Base maximum buy price for a 20% five-year IRR is **CAD 37.155791**, calculated as CAD 92.455498 divided by 1.20^5.

Net-SGD diagnostic

The same P/E terminal values, distributions and scenario weights are used. Entry CAD/SGD is 0.9154155987 SGD per CAD, derived as 1 / 1.0924 from the Bank of Canada 2026-09-04 daily rate. Exit CAD/SGD stresses are 0.84 Bear, 0.9154155987 Base and 0.99 Bull; these are analyst stresses correlated with commodity outcomes, not forecasts. Entry cost is 0.20%; exit liquidation plus FX cost is 0.20%. Canadian withholding is 15% of modeled cumulative distributions for a Singapore-resident beneficial owner under the Canada-Singapore treaty. Incremental Singapore capital-gains tax is assumed 0% only for a non-trading individual diagnostic. Investor wrapper, residence and broker facts are unavailable.

Official references: [Bank of Canada daily exchange rates](https://www.bankofcanada.ca/rates/exchange/daily-exchange-rates/) and [Canada-Singapore tax convention](https://www.canada.ca/en/department-finance/programs/tax-policy/tax-treaties/country/singapore-convention-1976.html).

Entry wealth is `93.14 Ã- 0.9154155987 Ã- 1.002 = SGD 85.4323324806`. Scenario terminal net-SGD wealth is `(terminal P/E share value + 85% of CAD distributions) Ã- scenario exit FX Ã- 0.998`.

Case	Weight	Exit CAD/SGD	Terminal net-SGD wealth / share	Net-SGD IRR
Bear	28%	0.8400000000	28.416954	(19.76)%

Case	Weight	Exit CAD/SGD	Terminal net-SGD wealth / share	Net-SGD IRR
Base	52%	0.9154155987	82.521567	(0.69)%
Bull	20%	0.9900000000	110.210343	5.23%
Probability weighted	100%	Scenario-specific	72.910031	(3.12)%

Probability-weighted net-SGD IRR is the CAGR of expected terminal net-SGD wealth: `(72.9100306164 / 85.4323324806)^(1 / 5.0) - 1 = -3.1202513483%`.

10. Hard Veto Checklist

#	Hard-veto test	Status	Evidence
1	ROIIC below cost of capital with no credible improvement path	WATCH	ROIIC unavailable; ROIC below 12% in four of five years; cost program not yet sustained proof
2	ROIC flattered by tiny or negative invested capital	PASS	FY2025 invested capital CAD 59.857B; ROIC only 9.95%
3	Growth needs persistent external financing	PASS	TTM FCF CAD 10.327B and low net debt support internal funding
4	Share count rises without value creation	PASS	Diluted shares fell materially
5	Large acquisitions without disclosed returns	WATCH	Fort Hills return is not isolated; no serial M&A pattern
6	FCF structurally lags earnings	PASS	Aggregate five-observation FCF/NOPAT 118.62%
7	Cyclicality, regulation or leverage can permanently impair equity	**FAIL**	Commodity, carbon, reclamation and demand-transition exposure; Moat/2046 failed
8	20% case requires multiple expansion	**FAIL**	Base requires 27.80x P/E versus comparable normalized current 19.19x
9	Today's price requires flawless execution	**FAIL**	Base is near zero return; Bull only 4.11% gross CAD
10	Moat cannot be explained in one paragraph	PASS	Asset/integration advantage is clear, though not pricing power
11	Accounting, governance or auditor issues impair trust	PASS	No identified material control, restatement or related-party issue
12	Balance-sheet risk could wipe out equity in a downturn	PASS	Low net debt and available liquidity; scenario EPS stays positive

At least one hard veto exists, so the score-implied classification cannot be Investable now or Buy only at lower price under the rubric. The low total score independently forces Reject.

11. Final Decision

Score-implied classification: Reject. This is the compounder rubric's diagnostic result, not an ER2 verdict override and not a portfolio, sizing, trade, ranking, message or dashboard instruction. The failed moat/2046 evidence, unavailable credible ROIIC and deeply inadequate locked returns overwhelm the genuinely strong cash conversion, balance sheet and share shrinkage.

Compounder Score note: 45/100 => Reject. Strong cash conversion, balance sheet and share shrinkage do not offset unproven ROIIC, a failed moat/2046 test and return outcomes far below 20%.

Business Quality Score note: 43/80 => Below the 65/80 investable threshold. Physical integration and execution resilience are real, but commodity pricing, cyclical returns, limited long-run demand visibility and unavailable credible ROIIC cap the score.

20% Return UW Score note: 2/20 => Fails. The Base 20% reverse-return requires 27.7989106001x P/E versus normalized current 19.1851402501x, major expansion of 44.8981%; all locked scenarios miss the hurdle.

12. Machine-Readable JSON

The full-precision companion artifact is `C:/Users/Admin/OneDrive/GPT/ER 2.0/Suncor Energy Inc/compounder_score.json`. Core values reproduced here:


```
{
  "business_quality_score": 43,
  "business_quality_score_max": 80,
  "valuation_underwriting_score": 2,
  "valuation_underwriting_score_max": 20,
  "total_score": 45,
  "total_score_max": 100,
  "classification": "Reject",
  "primary_valuation_method": "PE",
  "scenario_probabilities_pct": {"bear": 28.0, "base": 52.0, "bull": 20.0},
  "bear_case_irr": -0.1751894002538421,
  "base_case_irr": -0.00147417463661903,
  "bull_case_irr": 0.04110677763046855,
  "probability_weighted_irr": -0.027984077155116083,
  "probability_weighted_irr_method": "CAGR_OF_PROBABILITY_WEIGHTED_TERMINAL_WEALTH",
  "net_sgd_irr": {"bear": -0.19759975424998788, "base": -0.0069090125367679, "bull": 0.05225262494595029, "probability_
  "valuation_preflight_sha256": "3ff196132fb7f68906bba300d74c2b3db1ad6ec6f8354f444eec7a97a6afbd07"
}
```

Appendix CSA - Scoring Audit

Suncor Energy Inc. - Independent Scoring Audit

Ticker: SU.TO **Analysis date:** 2026-09-07 **Current price:** CAD 93.14 **TTM end:** 2026-06-30 **Horizon:** 2031-06-30, exactly 5.0 years **Clearance: SCORING AUDIT CLEARED - 45/100; BUSINESS QUALITY 43/80; 20% RETURN UW 2/20**

The same-worker CS repair is complete. The revised Category 6B score is 0/4 because a 20% Base return requires a 27.7989106001x terminal P/E, 44.8981% above the comparable normalized current 19.1851402501x P/E. All score arithmetic, evidence caps, hard vetoes, P/E return bridges, exact 28%/52%/20% probability-weighted terminal wealth and the root-specified net-SGD overlay now replay without a material mismatch. No upstream file was edited by CSA.

1. Original vs Audited Scores

Item	Original	Audited	Notes
Business Quality Score / 80	43/80	43/80	All five quality-category subtotals replay
Valuation / 20% Return UW Score / 20	2/20	2/20	Category 6B is correctly 0/4 after repair
Total Score / 100	45/100	45/100	43 + 2 = 45
Classification	Reject	Reject	Score below 70 and hard vetoes remain

Input hashes independently recomputed:

- `appendix_compounder_score.md`: `0a5badc9e751dc5434b708be11f25380f21287038d1d0ff8e81ebce6f033343f`
- `compounder_score.json`: `959b8d61d03bc4cb5407548bc7054c3fdc9bf75f3ab5abcb61b7737a61d6f020`
- `valuation_preflight.json`: `3ff196132fb7f68906bba300d74c2b3db1ad6ec6f8354f444eec7a97a6afbd07`
- `appendix_synthesis.md`: `beb2f5acb31c1bfbb9299f8c6ea5bdd7006a8e4dee43a6ab4f75c5c4471f48ee`

The repository validator returned `VALUATION_PREFLIGHT_VALID` with `--check-evidence-files`. The artifact is `CLEARED`, all five foundations pass, blockers are empty, and every CS and VP evidence-file hash matches its current bytes. CS exactly copies VP's primary P/E method, normalized current denominator, capital-structure treatment and Bear/Base/Bull 12.0x/10.0x/7.0x exit P/Es.

Category subtotal replay

Category	Original	Audited	Audit conclusion
1. Incremental Returns on Capital	9/25	9/25	Preserved
2. Reinvestment Runway	12/20	12/20	Preserved; partial evidence and long-duration gaps are reflected
3. Durability of Moat	6/15	6/15	Preserved; pricing power, stickiness and disruption points are withheld
4. Accounting and Financial Quality	9/10	9/10	Preserved
5. Capital Allocation	7/10	7/10	Preserved; missing deal returns cap acquisition credit
6. Price and 20% Underwriting	2/20	2/20	Preserved after the 6B repair

Subcategory replay

Item	Original	Audited	Evidence status	Decision
1A Normalized ROIC	2/5	2/5	Supported	Five-observation median is 11.85%, within the 10%-15% rubric band
1B ROIIC	0/8	0/8	Missing data	Standard and acquisition-inclusive ROIIC cannot be credibly calculated

Item	Original	Audited	Evidence status	Decision
1C ROIIC trend	0/3	0/3	Partly supported	NOPAT falls sharply from the FY2022 cycle peak
1D Unit economics	2/3	2/3	Partly supported	Integration and unit-cost evidence exist, but returns remain commodity-led
1E Cash conversion	3/3	3/3	Supported	FY2021-FY2025 aggregate FCF/NOPAT is 118.6175%
1F ROIC not artifact	2/3	2/3	Partly supported	Invested capital is meaningful; incomplete lease/R&D and ex-goodwill history cap credit
2A Market opportunity	3/5	3/5	Partly supported	Five-year runway is real; 2046 demand and policy evidence is weak
2B Reinvestment at scale	3/5	3/5	Partly supported	Brownfield delivery is observable; isolated project returns are unavailable
2C Organic growth	3/4	3/4	Partly supported	Current projects and operating evidence support opportunity, not certainty
2D Repeatable playbook	2/3	2/3	Partly supported	Recent execution is observable; the new team is not cycle-tested
2E Market structure	1/2	1/2	Supported	Installed scarcity helps while global supply/demand cap economics
2F Growth without ROIC collapse	0/1	0/1	Unsupported	Not proven across a commodity cycle
3A Source of advantage	3/4	3/4	Supported	Infrastructure, integration and operating learning are documented
3B Pricing power	0/3	0/3	Supported at zero	Commodity benchmarks and crack spreads control economics
3C Competitive evidence	1/3	1/3	Partly supported	Peers own comparable assets and pursue similar brownfield strategies
3D Customer stickiness	0/2	0/2	Supported at zero	No material upstream switching cost; retail fuel is competitive
3E Stress resilience	2/2	2/2	Supported	All reporting segments remained profitable across FY2021-FY2025
3F Low disruption risk	0/1	0/1	Supported at zero	Carbon, policy, transition and reserve-replacement risks are material
4A Earnings quality	1/2	1/2	Supported	Statutory bridge is clean, but TTM is cycle/event heavy
4B Cash flow supports earnings	2/2	2/2	Supported	Five-year and TTM conversion tie
4C SBC and dilution	2/2	2/2	Supported	SBC is expensed, issuance modeled, and net shares shrink
4D Balance-sheet strength	2/2	2/2	Supported	Q2 2026 net debt ex leases CAD 4.481B; available credit CAD 5.307B
4E Disclosure	1/1	1/1	Supported	Gaps and reconciliation logic are explicit
4F Governance/accounting red flags	1/1	1/1	Supported	No identified material control, restatement or related-party issue
5A Reinvestment priority	2/2	2/2	Partly supported	Capital hierarchy is consistent; project-return proof is incomplete

Item	Original	Audited	Evidence status	Decision
5B Acquisition discipline	1/2	1/2	Partly supported	No serial empire building; Fort Hills deal economics are undisclosed
5C Buyback discipline	1/2	1/2	Supported	Share shrinkage is real; cadence is capacity-led rather than valuation-led
5D Incentive alignment	2/2	2/2	Supported	TSR/ROCE measures and cash gate are documented
5E Owner mentality	0/1	0/1	Supported at zero	CEO actual common-share ownership was zero at the proxy date
5F Past decisions	1/1	1/1	Supported	Reliability, debt reduction and share shrinkage are observable
6A Base IRR	0/6	0/6	Supported	Base gross CAD IRR is -0.147417%
6B Conservative exit multiple	0/4	0/4	Supported	The 20% Base case needs major 44.8981% P/E expansion
6C Bear acceptable	0/3	0/3	Supported	Bear gross CAD IRR is -17.518940%
6D Reverse hurdle	0/3	0/3	Supported	Required EPS CAD 21.75735668 is 2.78x modeled Base EPS
6E Price does not imply perfection	0/2	0/2	Supported	Base is near zero and Bull only 4.11%
6F Cash returns help	2/2	2/2	Supported	CAD 11.053650-CAD 15.844268 distributions improve terminal wealth

2. Score Reductions and Reasons

No further score reduction is required. The repaired scorer now applies the major-expansion rule exactly: 6B is 0/4, Category 6 is 2/20, and the total is 45/100. The fixed denominators are preserved throughout.

The evidence does not support any positive ROIIC score, and CS correctly leaves 1B at zero. Acquisition-inclusive ROIIC remains unavailable and 5B remains capped at 1/2. Qualitative runway and moat points are supported by a mix of historical operations, current project status, industry structure and explicit external context; the score does not convert management's long-range claims into full credit.

3. Unsupported Claims

No awarded point depends on a wholly unsupported crucial claim. The following gaps remain explicit and already constrain scores:

- Standard 3-year, 5-year and acquisition-inclusive ROIIC are unavailable because depletion makes net-capex unstable, working-capital movements reverse, and deal-level returns are undisclosed.
- Ten-year ROIC, margin, FCF-conversion and dilution histories are unavailable in the reviewed package.
- Full project-level growth versus sustaining capital, comprehensive E&P reserve replacement, every project breakeven and a multi-year ex-goodwill ROIC series are unavailable.
- Investor-specific residence, wrapper and broker facts are unavailable; net-SGD is correctly labeled diagnostic.

4. Calculation Errors

Operating-quality replay

The five annual NOPAT / invested-capital observations reproduce 8.7385%, 19.2123%, 11.8525%, 11.9151% and 9.9454%, with a median of 11.8525%. Implied annual normalized tax rates reproduce 26.0461%, 26.2980%, 21.6640%, 26.5191% and 25.5410%. FY2025 ex-goodwill/intangibles ROIC is approximately 10.5546% using CAD 5.953B NOPAT and CAD 56.402B invested capital; a five-year ex-goodwill series is unavailable, so 1F remains capped.

FY2021-FY2025 FCF totals CAD 40.687B and NOPAT totals CAD 34.301B, reproducing 118.6175% conversion. Revenue, NOPAT, FCF and diluted-share CAGRs reproduce 5.7333%, 6.3818%, -0.9998% and -4.8593%. FY2025 SBC/revenue and SBC/FCF reproduce 0.9671% and 6.8303%. FY2023-FY2025 gross capex totals CAD 18.167B while NOPAT falls, so the evidence cannot justify positive ROIIC points.

One non-material upstream narrative typo remains: `quant_foundation.md` states `8,927 / 1,195.5 = 7.466332`; exact division is CAD 7.4671685487. VP and CS use the correct exact value, so current P/E and all return conclusions are unaffected. This is not a CSA clearance blocker.

P/E wealth bridge replay

Case	EPS	Exit P/E	Equity value/share	Distributions/share	Terminal wealth/share	Gross CAD IRR
Bear	2.041825	12.0x	24.501900	11.053650	35.555550	-17.5189400254%
Base	7.826694	10.0x	78.266940	14.188558	92.455498	-0.1474174637%
Bull	14.011292	7.0x	98.079044	15.844268	113.923312	4.1106777630%

Every row reproduces `(terminal wealth / 93.14)^(1/5)-1`. The P/E method remains locked at 12.0x/10.0x/7.0x. No terminal cash is added, no debt or leases are subtracted, and no non-operating asset is added after `EPS x P/E`. Distributions are added exactly once. Total terminal equity values of CAD 28.3632056055B, CAD 79.4771980510B and CAD 96.4103698098B tie to terminal diluted shares.

The reported TTM P/E of 12.4732687353x is event-heavy and disclosure-only. The comparable normalized current P/E is 19.1851402501x. The raw multiple was not used as a cap. FY2021-FY2025 historical diluted P/Es independently show 11.4260x, 6.5773x, 6.7062x, 10.8708x and 12.5608x. Bear 12x avoids applying a peak-earnings trough multiple to depressed earnings; Base 10x is an interior through-cycle anchor; Bull 7x avoids combining peak EPS with a premium multiple. Both excessive-optimism and excessive-bearishness challenges pass.

Probability-weighted wealth replay

`0.28 x 35.555550 + 0.52 x 92.455498 + 0.20 x 113.923312 = CAD 80.81707536`.

`(80.81707536 / 93.14)^(1/5) - 1 = -2.7984077155%`.

This is the CAGR of exact 28%/52%/20% probability-weighted terminal wealth, not an arithmetic average of scenario IRRs.

Reverse-return replay

Required terminal wealth is `93.14 x 1.20^5 = CAD 231.7621248`. After Base distributions of CAD 14.188558, required equity value is CAD 217.5735668. At 10.0x P/E, required EPS is CAD 21.75735668, a 23.8482959470% CAGR from current statutory diluted EPS of CAD 7.4671685487. Holding modeled Base EPS constant requires 27.7989106001x P/E, 44.8981359411% above normalized current. The 20% maximum buy price is CAD 37.1557910558.

Net-SGD overlay replay

Entry wealth is `CAD 93.14 x 0.9154155987 SGD/CAD x 1.002 = SGD 85.4323324806`. The overlay uses the same P/E equity values, 85% of distributions after 15% withholding, scenario exit FX and a 0.998 exit-cost factor.

Case	Terminal net-SGD wealth/share	Net-SGD IRR
Bear	28.4169542958	-19.7599754250%
Base	82.5215670754	-0.6909012537%
Bull	110.2103426718	5.2252624946%

Exact 28%/52%/20% weighted terminal net-SGD wealth is SGD 72.9100306164, and its five-year CAGR is -3.1202513483%. The valuation method, scenario wealth bridge and exit P/Es remain unchanged; same-method and double-count checks pass.

5. Missing Data

The most important missing evidence is credible standard and acquisition-inclusive ROIIC. Also missing are ten-year quality history, deal-level Fort Hills economics, comprehensive project capital/return schedules, multi-year ex-goodwill ROIC and investor-specific net-SGD tax-wrapper facts. These gaps cap confidence at Medium but do not block the score or return audit.

6. Hard-Veto and Threshold Test Audit

Test	Audited result	Conclusion
Total score at least 80/100	FAIL	45/100
Business Quality at least 65/80	FAIL	43/80
Valuation / 20% UW at least 15/20	FAIL	2/20
ROIIC plus runway at least 35/45	FAIL	21/45
Base IRR at least 20%	FAIL	-0.147417%
Bear IRR at least 8%-10%	FAIL	-17.518940%
No hard vetoes	FAIL	Vetoes 7, 8 and 9 remain
No required multiple expansion	FAIL	20% Base needs 27.7989x versus 19.1851x normalized current P/E

Hard-veto statuses replay as 1 WATCH, 2 PASS, 3 PASS, 4 PASS, 5 WATCH, 6 PASS, 7 FAIL, 8 FAIL, 9 FAIL, 10 PASS, 11 PASS and 12 PASS. Veto 7 is supported by commodity, carbon, reclamation and transition exposure; veto 8 by the reverse-return calculation; veto 9 by near-zero Base and 4.11% Bull returns. These vetoes support Reject independently of the sub-70 score.

7. Final 20% Hurdle Pass/Fail

FAIL. Bear, Base and Bull gross CAD IRRs are -17.518940%, -0.147417% and 4.110678%. Even Bull misses 20%. A Base 20% outcome requires EPS almost 2.78x modeled Base or major terminal P/E expansion.

8. Dream Business / Dream Investment Classification

Neither. Suncor is not a dream business because high ROIIC is unproven, standardized ROIC is below 12% in four of five observations, pricing power is absent, and the Moat/2046 tests fail. It is not a dream investment at CAD 93.14 because all locked scenarios miss 20% and probability-weighted gross CAD return is negative.

The single biggest reason is starting price relative to normalized commodity-cycle earnings: even favorable Bull economics at a defensible peak-cycle multiple deliver only 4.11% gross CAD IRR.

9. Stage 7 Scorecard Notes

- **Compounder Score note:** 45/100 => Reject. Strong cash conversion, balance-sheet strength and share shrinkage do not offset unavailable ROIIC, failed long-duration moat evidence and returns far below 20%.
- **Business Quality Score note:** 43/80 => Below the 65/80 investable threshold. Physical integration and execution resilience are real, but commodity pricing, cyclical returns and unproven incremental returns cap quality.
- **20% Return UW Score note:** 2/20 => Fails. All locked scenarios miss 20%, Bear loses capital, and a Base 20% outcome needs major P/E expansion.

10. Auditor JSON

The structured audit is in `compounder_score_audit.json`. It preserves full-precision gross CAD and net-SGD return replays, repaired score/category arithmetic, preflight binding, method-integrity checks, directional challenges and the explicit clearance token.

Appendix RT - Red Team

Suncor Energy Inc. â€” Red Team

Red-team date: 2026-09-07 **Security:** SU.TO common shares **Sealed price and horizon:** C$93.14; 2026-06-30 to 2031-06-30, exactly 5.0 years **Audited outcome preserved:** Compounder Score 45/100, Business Quality 43/80, 20% Return Underwriting 2/20; **Reject Gate state preserved:** Management YELLOW; Moat FAIL; 2046 FAIL; P/E-15 entry test PASS **RETURN_MODEL_OBJECTION_STATUS: IMMATERIAL**

1. The most fragile assumption

The most fragile assumption is the **Oil Sands Base-case operating combination** embedded in the C$23.671B horizon revenue line and 29.7157% pretax margin: 900 Mbbls/d average production, Fort Hills at 200 Mbbls/d, US$75 WTI, a US$13 WTI-WCS differential, and Oil Sands/Fort Hills/Syncrude cash costs of C$27/C$31/C$32 per barrel. None of those inputs is individually heroic. Their simultaneous persistence under a less-than-C$6B company-wide annual capital envelope is fragile because mine, upgrader, turnaround, tailings, and weather risks are correlated. Q2 2026 already showed the mechanism: production was hit by an estimated 50â€“60 Mbbls/d while Oil Sands, Fort Hills, and Syncrude costs rose to C$32.70/C$44.50/C$40.15 per barrel.

The synthesis sensitivity shows that cutting the Oil Sands revenue CAGR by 200 basis points, from 2.5331% to 0.5331%, lowers horizon EPS from C$7.826694 to C$7.344280, a C$0.482414 or 6.2% reduction. That sensitivity still leaves the Base margin unchanged and therefore understates a real reliability miss, in which volume falls while unit cost rises. At 900 Mbbls/d, the segment appendix estimates approximately C$329M of annual pretax exposure for each C$1/bbl cost change. An C$8/bbl miss versus the C$27 Base Oil Sands cost cross-check would therefore remove about C$2.632B of pretax profit before secondary effects. Applying the Base 25.75% tax rate and terminal share count would lower EPS by roughly C$1.9245, to about C$5.90. At 10Ã- plus the locked C$14.188558 distributions, Base terminal wealth would fall to about C$73.21 and gross IRR to about **-4.70%**, versus the audited -0.1474%. That is the operating path most capable of breaking even the already-poor Base return.

Recent peer evidence cuts both ways. Cenovus reported record Q2 2026 Oil Sands production and reduced its 2026 Oil Sands operating-cost guidance by about 6% without raising capital guidance, proving brownfield cost-and-volume improvement is achievable. It also shows the playbook is available to a direct competitor rather than proprietary to Suncor. [Cenovus Q2 2026 results](https://www.cenovus.com/News-and-Stories/News-releases/2026/3335023)

2. The most-likely-to-be-optimistic Stage 5 number

The single Stage 5 number most likely to be revised down is **C$22.0B of cumulative Base-case repurchases**. It is the cash action that produces the optimistic 1,015.463209M terminal diluted-share count. The path averages C$4.4B a year versus C$3.456B in the TTM, while dividends consume another C$15.5B and management keeps company-wide capex near C$6B. The assumed annual average buyback price rises from C$100 to C$128, even though the audited Base terminal equity value is only C$78.26694 per share before dividends. This is not an arithmetic error, but it exposes the economic tension: management would be using increasingly valuable cash to retire stock at prices above the modelâ€™s own terminal equity value.

Stage 5 does not provide a full annual free-cash-flow bridge tying operating cash, capex, dividends, buybacks, cash, and debt in each scenario. It explicitly labels the buyback and balance-sheet paths as assumptions. A 5% higher terminal share count lowers Base EPS to C$7.453994, terminal wealth to C$88.728498, and IRR to **-0.9658%**. That is only an 82-basis-point deterioration, so it does not create a material return-model objection; it does show why the P/E-15 PASS should not be read as a robust margin of safety.

3. The strongest bear case, in its strongest form

Suncor is being priced as though a recent reliability reset can convert benchmark-driven assets into a durable per-share compounder, but the company still has no pricing power and its best operating practices are reproducible by CNRL, Cenovus, and Imperial. By 2027â€“2029, global supply capacity can outgrow demand while mature E&P declines, gasoline demand erodes, and carbon/tailings capital competes with the same sub-C$6B budget required to hold Oil Sands reliability. The IEAâ€™s medium-term work projects 5.1 mb/d of supply-capacity growth against only 2.5 mb/d of demand growth through 2030, the external mechanism that can keep WTI and crack spreads below the modelâ€™s favorable states. [IEA Oil 2025

executive summary](https://www.iea.org/reports/oil-2025/executive-summary) The confirming signal would be Oil Sands output below 800 Mbbls/d together with unit cash cost above C$35/bbl for two consecutive quarters: that would show fixed-cost deleverage, not a one-quarter commodity mark, and would make the 900 Mbbls/d/C$27 Base operating pair untenable.

4. Cross-examination of management commentary

â€œAnother 100,000 barrels a day of upstream production growth.â€■ Rich Kruger made this three-year commitment on the Q1 2026 call. Stage 5 allocates 75 Mbbls/d to Oil Sands and then assumes another 25.6 Mbbls/d of analytical debottlenecking to reach 900 Mbbls/d by 2031. The weak point is not the announced projects; it is gross-to-net attribution after natural decline, maintenance, ore access, and partner-controlled offshore schedules. If the promise is slipping, the first evidence will be annualized Oil Sands production failing to reach roughly 875 Mbbls/d by 2029 despite capital remaining near the ceiling, with E&P production also failing to hold its Base path.

â€œA further $5 a barrel reduction in enterprise breakeven.â€■ Kruger stated this on the Q1 2026 call as a three-year target. The package does not provide a reproducible company-wide breakeven bridge separating sustainable unit-cost improvement from oil price, royalties, working capital, planned-maintenance timing, or repurchase pacing. Q2 2026 demonstrates how quickly weather and maintenance can reverse unit-cost progress. The first contradiction would be an inflation-adjusted two-year rise in Oil Sands cash cost per barrel while sustaining capital remains at or above plan; cash cost above C$35/bbl through two results periods would be incompatible with the Base economics.

â€œ$500 million a month buyback.â€■ Troy Little described the Q2 2026 cadence, but management also framed leverage near one times net debt to cash flow at US$50 WTI as a guardrail. The quotation is therefore conditional capital allocation, not a five-year entitlement. Stage 5 sensibly models less than C$6B annually in Base, yet still assumes C$22B cumulatively while price rises. The first failure would appear in repurchase cash falling below C$3B over a trailing twelve months while cash declines or debt rises; the share denominator would then miss before the terminal income statement did.

5. Stage 5 tie-out reverification and valuation-preflight locks

All six mandatory inputs hash-match the sealed values:

Sealed input	Verified SHA-256
`valuation_preflight.json`	`3ff196132fb7f68906bba300d74c2b3db1ad6ec6f8354f444eec7a97a6afbd07`
`appendix_synthesis.md`	`beb2f5acb31c1bfbb9299f8c6ea5bdd7006a8e4dee43a6ab4f75c5c4471f48ee`
`appendix_compounder_score.md`	`0a5badc9e751dc5434b708be11f25380f21287038d1d0ff8e81ebce6f033343f`
`compounder_score.json`	`959b8d61d03bc4cb5407548bc7054c3fdc9bf75f3ab5abcb61b7737a61d6f020`
`appendix_scoring_audit.md`	`784aa79852b8be0c4a3cce4e24e6243c6be5621302d3ca45e3e1c021d3f427bd`
`compounder_score_audit.json`	`8c1b05f59d310da9d13f776a392b6885b86aa1186a8a1033fba33e64e82bd0ca`

`valuation_preflight.json` is CLEARED and locks P/E as the sole primary method; EV/NOPAT is rejected because the complete enterprise-to-equity claim path is unavailable, while P/B-ROE is secondary and lacks a zero-residual common-equity roll-forward. The reported TTM EPS of C$7.4671685487 and P/E of 12.4732687353Ã- are event-heavy and disclosure-only. The normalized current denominator is FY2025 EPS of C$4.8547990156, giving a directly recomputed comparable P/E of 19.1851402501Ã-. Terminal statutory diluted EPS is C$2.041825/C$7.826694/C$14.011292 for Bear/Base/Bull; exit P/Es are exactly 12Ã-/10Ã-/7Ã-. The same P/E method controls all scenarios, probability weighting, reverse return, and net-SGD. No terminal cash is added, and no debt, lease, senior claim, or non-operating asset is subtracted after EPS Ã- P/E. The insurer lane is not triggered.

The recency anchor uses Q3 2025, derived standalone Q4 2025, Q1 2026, and Q2 2026 without overlap. It ties arithmetically, but its economic signal is bifurcated rather than smooth: Q2 Oil Sands revenue rose 25.9% year over year with a 44.5% pretax margin while production was depressed by weather and maintenance; Q2 R&M revenue rose 62.3% with a 17.8% margin; E&P revenue rose 72.5% with a 40.5% margin. Stage 5 does not extrapolate those comparisons, which is correct. The remaining risk is that TTM revenue is an unstable mixture of high realization and low physical uptime; a neat five-year

CAGR can obscure the interaction.

No segment Base CAGR exceeds recent peer behavior without a named mechanism. Oil Sands uses brownfield volume and cost improvement, E&P uses West White Rose and development drilling, and R&M uses diesel yield and channels. Cenovusâ€™s Q2 evidenceâ€”record Oil Sands output, a lower cost guide, and West White Rose still targeted for first oilâ€”supports feasibility, but it also shows unplanned Foster Creek and offshore/turnaround disruptions in the same quarter. That is exactly why execution should be modeled as a distribution, not a durable moat.

The share paths tie: 1,179.0M opening shares less repurchased shares plus estimated SBC issuance equals 1,157.592089M/1,015.463209M/982.986435M. The distribution arithmetic also ties. What is missing is not a formula but a full annual cash-capacity proof for C$5B/C$22B/C$30B of repurchases alongside dividends, capex, and debt/cash changes.

6. Score-derived 20% return claim most likely to be wrong

The audited score already says the 20% return case does **not** clear, and the red team agrees. Required terminal wealth is C$231.7621248. After Base distributions of C$14.188558 and at the locked 10Ã- P/E, required EPS is C$21.75735668, 2.78 times modeled Base EPS. Holding Base EPS constant instead requires 27.7989106Ã-, 44.8981% above normalized current P/E. No plausible share-count adjustment bridges that gap: at Base net income of C$7.94772B, C$21.757 EPS would require only about 365M shares, versus 1,015M modeled.

The score-derived claim most open to semantic misuse is not the FAIL itself but the statement that â€œcash returns help.â€■ They help the bridge by C$11.05â€“C$15.84 per share, yet do not make 20% plausible and are conditional on the same commodity cash flows supporting capex and buybacks. To overturn the FAIL, Oil Sands pretax earnings would need to rise far beyond Base without consuming the distributions, or a structurally unjustified exit multiple would have to do the work. The 20% hurdle conclusion is robust.

7. Two-sided valuation challenge

Strongest reason the audited model may be too optimistic. Bearâ€™s **12Ã- exit P/E** is the most generous locked valuation assumption. The rationale treats C$2.041825 EPS as a cyclical trough deserving an inverse-cycle multiple, but the Bear operating state is not a single recession year: it is five years ending with 720 Mbbls/d Oil Sands production, C$38â€“C$44/bbl costs, a US$20 differential, E&P profit nearly extinguished, and R&M at a 6.47% pretax margin. If those are evidence of structural erosion rather than temporary trough earnings, 8Ã-â€”inside the companyâ€™s observed 6.58Ã-â€“12.56Ã- rangeâ€”is a defensible stress. Bear terminal wealth would fall from C$35.555550 to C$27.388250 and IRR from **-17.5189% to -21.7137%**. Because Bear has only 28% weight, probability-weighted wealth falls from C$80.817075 to C$78.530231 and its IRR from **-2.7984% to -3.3548%**. This is the strongest optimistic challenge, but it is a non-controlling stress, not evidence that the sealed 12Ã- is invalid: trough earnings convention and the historical range still support the lock.

Strongest reason the audited model may be too bearish. Bullâ€™s **7Ã- exit P/E** assumes the C$14.011292 EPS denominator is peak-cycle and compresses the multiple to the FY2022â€“FY2023 peak-earnings observations. That is disciplined, but potentially punitive if some earnings are structuralâ€”900-plus Mbbls/d brownfield output, better reliability, lower debt, and stronger downstream diesel/logistics mixâ€”rather than a transient commodity spike. A clearly labeled 9Ã- sensitivity raises Bull terminal wealth from C$113.923312 to C$141.945896 and Bull IRR from **4.1107% to 8.7921%**. At the 20% Bull weight, probability-weighted IRR rises only to **-1.4862%**. Even the strongest bearishness rebuttal does not produce a BUY or approach 20%.

The competing sensitivities are deliberately not spliced into the audited bridge. The 12Ã-/10Ã-/7Ã- multiples were selected before returns, match denominator perimeters, and have evidence anchors in Suncorâ€™s own cycle history. Alternative 8Ã- Bear and 9Ã- Bull values show valuation range, not a supportable correction to a broken input. Consequently there is no invalid denominator, method switch, claim-perimeter error, double count, or correction that should route the model back upstream. **RETURN_MODEL_OBJECTION_STATUS: IMMATERIAL.**

8. Return arithmetic, probability weighting, and insurer applicability

The gross CAD bridge reproduces exactly:

Scenario	EPS Ã- P/E	Distributions	Terminal wealth	Gross CAD IRR
Bear	C$24.501900	C$11.053650	C$35.555550	-17.518940%
Base	C$78.266940	C$14.188558	C$92.455498	-0.147417%

Scenario	EPS Ã- P/E	Distributions	Terminal wealth	Gross CAD IRR
Bull	C$98.079044	C$15.844268	C$113.923312	4.110678%

Each return equals `(terminal wealth / 93.14)^(1/5)-1`. Probability-weighted wealth is `28% Ã- 35.555550 + 52% Ã- 92.455498 + 20% Ã- 113.923312 = C$80.81707536`; its CAGR is **-2.798408%**. Scenario IRRs are not averaged.

The net-SGD overlay also reproduces: entry wealth is SGD85.4323324806; Bear/Base/Bull terminal net wealth is SGD28.4169542958/SGD82.5215670754/SGD110.2103426718, giving **-19.759975%/-0.690901%/5.225262%**. Weighted terminal net wealth is SGD72.9100306164 and its CAGR is **-3.120251%**. It uses the same P/E equity values, scenario weights, 85% of dividends after withholding, scenario FX, and costs.

Suncor is not a P&C insurer, reinsurer, or analogous risk-bearing financial business. `insurer_return_bridge.json` is therefore correctly absent; retained-managed perimeter, fee/NCI, common-book, P/B-ROE, and negative-EPS-to-zero-equity tests are not applicable.

9. The signal that forces an exit

The forcing signal is **Oil Sands unit cash cost above C$35/bbl while average Oil Sands production remains below 800 Mbbls/d for two consecutive reported quarters**. Both thresholds must persist to filter out a planned turnaround or one weather event. C$35 is C$8 above the Base Oil Sands cost cross-check; below 800 Mbbls/d is more than 11% below the 900 Mbbls/d Base endpoint and below the level needed for fixed-cost absorption. On the segment sensitivity, the cost gap alone is roughly C$2.6B of annual pretax pressure, enough to drive Base EPS toward C$5.90 and Base IRR toward -4.7%. The combination would falsify managementâ€™s â€œhigher volumes, lower unit costsâ€■ loop and show that the moat is replacement-cost scarcity without improving shareholder economics.

10. Conviction at the end of red team

The thesis does NOT survive this red team. The break is not insolvency, accounting, or a missing arithmetic tie-out. It is that an operationally credible integrated producer with a sound balance sheet is being asked to deliver compounder returns from commodity-priced, capital-intensive assets at C$93.14. Even granting Base execution and C$22B of buybacks produces a slightly negative gross CAD IRR; even raising the Bull exit from 7Ã- to 9Ã- produces only 8.79% in that scenario and leaves the probability-weighted outcome negative. The synthesis should be read around the narrative **â€œdurable assets, insufficient return at the sealed price,â€■** with the P/E-15 PASS explicitly subordinated to the failed moat, 2046, score, and return tests.

Appendix D - Data Package (raw historicals)

Suncor Energy Inc. â€” Data Package

Information date: 2026-09-06 SGT. Ticker: SU.TO. Reporting currency: CAD. Unless stated otherwise, dollar amounts are CAD millions, volumes are working-interest before royalties, and fiscal years end December 31. This file is the Wave 1 historical and disclosure package only; it contains no forecast, valuation, score, or investment verdict.

0a. Industry classification and disclosure inventory

Suncor is a Canadian integrated commodity/energy issuer reporting under IFRS, filing Form 40-F and 6-K in the United States, and operating upstream oil-sands and conventional/offshore production together with downstream refining, marketing, logistics, and retail. FMP's live annual and quarterly `revenue-product-segmentation` endpoints both returned exact empty arrays in this run. The controlling source set is Suncor's official FY2021-FY2025 AIF, audited financial statements and MD&A archived live from SEC EDGAR; the last four official quarterly reports and results releases; official call transcripts or FMP live transcripts; and the March 31, 2026 Investor Day material. Official filings override material FMP classification differences.

The search inventory covered: `production`, `volume`, `realized price`, `price realization`, `differential`, `netback`, `cash operating costs`, `lifting cost`, `royalties`, `transportation and distribution`, `asset sustainment and maintenance`, `economic investment`, `capital expenditures`, `proved`, `probable`, `contingent resources`, `reserve life`, `depletion`, `replacement`, `breakeven`, `risk management`, `derivative`, `reclamation`, `decommissioning and restoration`, `refinery throughput`, `refinery utilization`, `refined product sales`, `gasoline`, `distillate`, and `margin capture`. Tables reviewed included the segmented statements of net earnings, revenue from contracts with customers, Oil Sands and E&P price realization reconciliations, cash-operating-cost reconciliations, reserves summaries, decommissioning provisions, capital expenditure schedules, financial-condition schedules, and downstream volume/margin tables.

Dataset / table family	Official source searched	Search terms or table names	Years available	Included in data package?	If excluded, why	Downstream relevance
Segment economics	FY2021-FY2025 audited FS and MD&A	Gross revenues; Earnings (loss) before income taxes; segment note	FY2021-FY2025; Q3 2025-Q2 2026	Yes	n/a	Segment appendices and synthesis
Production and utilization	Annual and quarterly MD&A	Total upstream production; upgraded; non-upgraded; refinery utilization	FY2021-FY2025; latest quarter	Yes	n/a	Volume and asset-utilization drivers
Realized prices and margins	Annual and Q2 2026 MD&A	Price realizations; FIFO/LIFO gross margin; margin capture	FY2021-FY2025; latest quarter	Yes	2026 realization-method change flagged	Price and mix sensitivity
Operating costs	Annual and Q2 2026 MD&A	Oil Sands operations; Fort Hills; Syncrude cash operating costs	FY2021-FY2025; latest quarter	Yes	n/a	Unit-cost and operating-leverage work
Royalties and transportation	Segment notes and MD&A	Less: royalties; transportation and distribution	FY2021-FY2025; H1 2026	Yes	n/a	Netback and statutory-revenue bridge
Sustaining and growth capital	Annual and quarterly MD&A	Asset sustainment and maintenance; economic investment	FY2021-FY2025; H1 2026 total	Yes	Q2 split summarized by project rather than annualized	Capital intensity and project pipeline
Reserves and resources	FY2021-FY2025 AIF; Investor Day	Proved plus probable; contingent resources; reserve life	FY2021-FY2025; March 2026	Yes	Issuer does not publish one consistent replacement-ratio series	Durability and depletion analysis
Hedging and contract coverage	FY2025 FS Note 29 and Q2 2026 MD&A	Risk management; derivative; contract; hedge	FY2025; H1 2026	Partly	Volumetric hedge book not separately disclosed	Commodity-risk analysis
Reclamation obligations	FY2021-FY2025 FS provisions notes; Q2 2026 cash flow	Decommissioning; restoration; liabilities settled	FY2021-FY2025; H1 2026 settlements	Yes	Q2 does not provide a full provision roll-forward	Long-tail liability and cash burden
Recent trend and guidance	Q3 2025-Q2 2026 reports, releases and calls; Investor Day	production; throughput; sales; guidance; breakeven	Last four quarters	Yes	FMP Q1 2026 transcript empty on identical retry; official IR transcript used	Recency and management anchors

Longest clean industry KPI histories

KPI family	Granularity	FY2021	FY2022	FY2023	FY2024	FY2025	Latest interim / TTM	Source path
Total Oil Sands production, mbbls/d	Segment	644.2	665.2	689.6	773.8	799.4	Q2 2026: 690.1	D-MD&A23; D-MD&A25; D-Q2-26
E&P production, mboe/d	Segment	87.5	78.0	56.1	53.8	60.8	Q2 2026: 70.8	D-MD&A23; D-MD&A25; D-Q2-26
Total upstream production, mboe/d	Consolidated upstream	731.7	743.2	745.7	827.6	860.2	Q2 2026: 760.9	D-MD&A23; D-MD&A25; D-Q2-26
Upgraded SCO and diesel realization, CAD/bbl	Oil Sands	77.73	118.88	99.40	97.91	87.79	H1 2026 new basis: 121.90	D-MD&A23; D-MD&A25; D-Q2-26
Non-upgraded bitumen realization, CAD/bbl	Oil Sands	53.80	84.63	67.97	72.65	62.02	H1 2026 new basis: 88.07	D-MD&A23; D-MD&A25; D-Q2-26
Oil Sands operations cash cost, CAD/bbl	Operated Base/In Situ	25.90	29.95	29.70	26.90	26.55	Q2 2026: 32.70	D-MD&A23; D-MD&A25; D-Q2-26
Fort Hills cash cost, CAD/bbl	Asset	41.35	30.00	34.40	32.80	33.10	Q2 2026: 44.50	D-MD&A23; D-MD&A25; D-Q2-26
Syncrude cash cost, CAD/bbl	Asset	35.20	36.65	37.15	35.15	33.70	Q2 2026: 40.15	D-MD&A23; D-MD&A25; D-Q2-26
Refinery crude processed, mbbls/d	Downstream	415.5	433.2	420.7	465.0	480.3	Q2 2026: 470.6	D-MD&A23; D-MD&A25; D-Q2-26
Refinery utilization, percent	Downstream	89	93	90	100	103	Q2 2026: 92 on rerated 511 mbbls/d capacity	D-MD&A23; D-MD&A25; D-Q2-26
Refined product sales, mbbls/d	Downstream	528.4	553.6	553.1	600.4	623.3	Q2 2026: 654.8	D-MD&A23; D-MD&A25; D-Q2-26
R&M gross margin FIFO, CAD/bbl	Downstream	36.85	55.85	45.00	36.40	37.60	Q2 2026: 69.65	D-MD&A23; D-MD&A25; D-Q2-26
R&M gross margin LIFO, CAD/bbl	Downstream	30.90	54.45	47.00	37.00	39.50	Q2 2026: 61.50	D-MD&A23; D-MD&A25; D-Q2-26
Refining operating expense, CAD/bbl	Downstream	5.95	7.00	7.45	6.60	6.50	Q2 2026: 6.35	D-MD&A23; D-MD&A25; D-Q2-26
Net proved plus probable reserves, million boe-equivalent	Company	5,783	5,483	6,185	6,085	6,265	FY-end only	D-AIF21 through D-AIF25
Approximate reserve life, years	Calculated: net 2P / annual production	21.7	20.2	22.7	20.1	20.0	Investor Day cited 25 years on a different stated perimeter	Calculation from preceding rows; D-ID26
Decommissioning and restoration provision	Company, CAD million	8,792	9,901	11,931	12,271	12,620	H1 2026 cash settlement: 290	D-FS21 through D-FS25; D-Q2-26

The annual price-realization series through FY2025 is net of transportation but before royalties. Beginning Q1 2026, Suncor revised price realizations to exclude transportation and distribution expenses and restated the comparative period; the H1 2026 values are therefore a new basis and are not directly spliced into the five-year annual series. Effective January 1, 2026, Suncor rerated refinery nameplate capacity from 466 mbbls/d to 511 mbbls/d; the Q2 2026 utilization rate is on that higher denominator and is not directly comparable with the FY2021-FY2025 as-published series. Cash-cost presentation was revised beginning 2022 to aggregate inventory changes and internal transfers; prior-period comparatives were updated, with no change to total cash costs or per-barrel amounts. Approximate reserve life above is an analyst calculation, not the issuer's reserve-life disclosure.

Latest official realizations, differentials, and operating netbacks

Q2 commodity KPI, CAD/bbl	Q2 2026	Q2 2025 comparative	Basis	Source
Upgraded net SCO and diesel realization	143.55	90.10	Before royalties; transportation excluded under the Q1 2026 method	D-Q2-26 live SEC filing
Non-upgraded bitumen realization	98.79	67.95	Before royalties; transportation excluded under the Q1 2026 method	D-Q2-26 live SEC filing
Oil Sands weighted-average crude realization	129.59	80.98	Mix-weighted upgraded and non-upgraded realization	D-Q2-26 live SEC filing
Oil Sands weighted-average crude relative to WTI	1.15	(7.18)	Disclosed differential; comparative restated to the current method	D-Q2-26 live SEC filing
Oil Sands operating netback, non-upgraded bitumen	51.57	31.76	Non-GAAP; after royalties, transport, and net operating expenses	D-Q2-26 live SEC filing
Oil Sands operating netback, upgraded net SCO and diesel	76.35	37.78	Non-GAAP; after royalties, transport, and net operating expenses	D-Q2-26 live SEC filing
E&P Canada operating netback	92.78	56.20	Non-GAAP; per barrel of disclosed Canada sales volumes	D-Q2-26 live SEC filing

The official Q2 2026 table is available at `https://www.sec.gov/Archives/edgar/data/311337/000110465926090544/su-20260804xex99d2.htm`. These current-period rows fill the commodity-checklist realization/differential/netback family without implying a comparable five-year netback series across Suncor's 2026 realization-method boundary.

Royalties, transportation, capital, and project inventory

KPI family	FY2021	FY2022	FY2023	FY2024	FY2025	Latest interim	Source
Royalties	2,001	4,571	3,114	4,192	3,469	H1 2026: 2,454	Official segment statements; D-Q2-26
Transportation and distribution	1,479	1,671	1,775	1,842	1,961	H1 2026: 1,130	Official segment statements; D-Q2-26
Asset sustainment and maintenance capital	3,057	3,315	3,543	3,185	3,162	Q2 projects listed; no H1 total used	Annual MD&A capital schedules
Economic investment capital	1,354	1,504	2,030	2,981	2,496	Q2 projects listed; no H1 total used	Annual MD&A capital schedules
Total capital including capitalized interest	4,555	5,120	5,828	6,483	5,856	H1 2026: 2,466	D-FMP-CFA; official cash-flow statements

Q2 2026 economic projects included additional In Situ pads and capacity, the Fort Hills North Pit second opening, Mildred Lake Mine Extension East and autonomous-haul preparation, the nearing-completion West White Rose project, and targeted R&M retail investments. Sustaining projects included Oil Sands maintenance/turnarounds and tailings development plus R&M refinery, retail, and logistics sustainment. FY2025 derivative balances were gross assets of 3,839 and gross liabilities of 3,646, largely offset to net derivative assets of 193 before other netting; no clean volumetric hedge schedule was found in the searched materials. The FY2025 decommissioning provision rose to 12,620; cash settlements were 505 in FY2025 and 290 in H1 2026.

1. Reporting structure and taxonomy

The current reportable segments are: **Oil Sands**, comprising Base Plant mining/upgrading, In Situ, Fort Hills and Syncrude; **Exploration and Production**, comprising offshore East Coast Canada and international interests, with Syria suspended and Libya presented on an economic basis for operational metrics; and **Refining and Marketing**, comprising refining, supply, trading, logistics, marketing, Petro-Canada retail/wholesale, and related infrastructure. **Corporate and Eliminations** captures activities not directly attributable to an operating segment and intersegment eliminations; it is not a modeled operating segment.

FY2025 official gross revenue	CAD million	Percent of consolidated gross revenue	Projection treatment	Source
Oil Sands	19,298	36.85%	Modeled segment	D-FS25 Note 28
Exploration and Production	2,509	4.79%	Modeled segment	D-FS25 Note 28
Refining and Marketing	30,569	58.36%	Modeled segment	D-FS25 Note 28
Corporate and Eliminations	1	0.00%	Bridge/context only	D-FS25 Note 28
Consolidated	52,377	100.00%	Control total	D-FS25 Note 28

Reporting labels have been stable across FY2021-FY2025. Economic comparability is not perfectly static: Suncor divested its U.K. E&P portfolio in 2023 and consolidated greater Fort Hills ownership in 2023, changing the ownership perimeter and E&P mix without changing the segment labels. In 2022 the cash-cost reconciliation presentation changed, with comparative periods restated. In Q1 2026 the price-realization methodology changed to exclude transportation, with comparative-quarter restatement. The product revenue note ceased showing a separate natural-gas line after FY2023; the remaining E&P revenue is presented as crude oil and natural gas liquids. No unannounced reclassification is inferred.

2. Consolidated historicals

FMP was live-fetched as required. FMP revenue equals the official `Operating revenues, net of royalties`, not official gross revenues. FMP `operatingIncome` differs materially from the issuer's statutory operating income before financing for FY2025; this table preserves the vendor fields while the QFR-sealed official bridge in Section 3a controls forecasting identity.

Metric	FY2021	FY2022	FY2023	FY2024	FY2025	Source
Revenue, CAD B, FMP post-royalty basis	39.132	58.336	49.092	50.689	48.908	D-FMP-IA `/stable/income-statement`
Operating income, CAD B, FMP field	6.285	13.925	8.678	9.035	7.995	D-FMP-IA
Operating margin, percent	16.06	23.87	17.68	17.82	16.35	Calculated from preceding FMP rows
Net income, CAD B	4.119	9.077	8.295	6.016	5.918	D-FMP-IA; official tie
EPS diluted, CAD	2.77	6.53	6.33	4.72	4.85	Official annual MD&A/FS
Diluted share count, million	1,489	1,390	1,310	1,276	1,220	D-FMP-IA; official tie
Capital expenditures, CAD B	4.555	5.120	5.828	6.483	5.856	D-FMP-CFA; official tie
Free cash flow, CAD B	7.209	10.560	6.516	9.477	6.925	D-FMP-CFA, OCF less capex
ROIC, percent, explicit calculation	8.74	19.21	11.85	11.92	9.95	Calculated below from live FMP fields

ROIC is consistently calculated as `NOPAT / year-end invested capital`, where NOPAT equals FMP operating income multiplied by one minus the live-FMP effective tax rate, and invested capital equals FMP total debt plus stockholders' equity less cash and short-term investments. NOPAT / invested capital was 4.648 / 53.190 in FY2021, 10.263 / 53.419 in FY2022, 6.798 / 57.355 in FY2023, 6.639 / 55.719 in FY2024, and 5.953 / 59.857 in FY2025. This is a standardized analytical ROIC, not Suncor's non-GAAP ROCE.

Official gross revenue / FMP revenue was 52.377 / 48.908 in FY2025. Official statutory operating income before financing / FMP operating income was 9.028 / 7.995. Official filings control the resulting 3.469 revenue and 1.033 operating-income classification gaps.

3. Segment historicals

The exact sealed common profit basis is **Earnings (loss) before income taxes**. It is an issuer-disclosed segment metric and is not renamed operating income.

Oil Sands	FY2021	FY2022	FY2023	FY2024	FY2025	Source
Gross revenue, CAD B	15.319	21.905	18.569	20.818	19.298	Official segment statements D-FS22, D-FS23, D-FS25
YoY percent	n/m	43.0	(15.2)	12.1	(7.3)	Calculated

Oil Sands	FY2021	FY2022	FY2023	FY2024	FY2025	Source
Earnings (loss) before income taxes, CAD B	2.825	5.633	6.811	6.607	5.277	Official segment statements
Margin on exact metric, percent	18.4	25.7	36.7	31.7	27.3	Calculated

Exploration and Production	FY2021	FY2022	FY2023	FY2024	FY2025	Source
Gross revenue, CAD B	2.978	4.331	2.689	2.798	2.509	Official segment statements D-FS22, D-FS23, D-FS25
YoY percent	n/m	45.4	(37.9)	4.1	(10.3)	Calculated
Earnings (loss) before income taxes, CAD B	1.791	3.221	1.691	0.867	0.526	Official segment statements
Margin on exact metric, percent	60.1	74.4	62.9	31.0	21.0	Calculated

Refining and Marketing	FY2021	FY2022	FY2023	FY2024	FY2025	Source
Gross revenue, CAD B	22.808	36.622	30.959	31.266	30.569	Official segment statements D-FS22, D-FS23, D-FS25
YoY percent	n/m	60.6	(15.5)	1.0	(2.2)	Calculated
Earnings (loss) before income taxes, CAD B	2.867	5.694	3.383	2.596	2.822	Official segment statements
Margin on exact metric, percent	12.6	15.5	10.9	8.3	9.2	Calculated

Corporate and Eliminations pretax results were losses of 1.913, 2.232, 1.296, 1.883, and 0.677 billion from FY2021 through FY2025, respectively. These remain bridge amounts, not a fourth operating forecast segment.

3a. Historical statutory-profit bridge and forecast-driver ledger

Sealed packet: `statutory_bridge.json`, schema 1.1.0. Reporting currency: CAD. Scale: millions. Segment-profit basis: `issuer_disclosed`. Modeled segment count: 3. The exact common segment metric for both periods is `Earnings (loss) before income taxes`. The source packet's expected SHA-256 is `fab6c20af72b9ac32c4bba687af9a32c3b9f0a764fd222ae134805fcc315ac88`.

FY2025, year ended 2025-12-31

Bridge line	Classification	Value	Source ID	Running subtotal
Oil Sands	segment profit	5,277	annual_fs	5,277
Exploration and Production	segment profit	526	annual_fs	5,803
Refining and Marketing	segment profit	2,822	annual_fs	8,625
Sum of reportable segment profit	subtotal	8,625	annual_fs	8,625
Corporate and Eliminations	corporate_unallocated	(677)	annual_fs	7,948
Consolidated segment profit metric	subtotal	7,948	annual_fs	7,948
Reverse financing expenses to reach earnings before financing expenses and income taxes	operating	1,080	annual_fs	9,028
Statutory operating income	statutory subtotal	9,028	annual_fs	9,028
Financing expenses	other_non_operating	(1,080)	annual_fs	7,948
Pretax income	statutory subtotal	7,948	annual_fs	7,948
Income tax expense	tax	(2,030)	annual_fs	5,918
Net income	statutory subtotal	5,918	annual_fs	5,918

Reconciliation residuals preserved from the sealed packet: segment sum 0; corporate bridge 0; operating-income bridge 0; pretax bridge 0; net-income bridge 0. Disclosed rounding unit and tolerance are both CAD 1 million.

TTM ended 2026-06-30

Bridge line	Classification	Value	Source ID	Running subtotal
Oil Sands	segment profit	6,965	ttm_recon	6,965
Exploration and Production	segment profit	1,050	ttm_recon	8,015
Refining and Marketing	segment profit	5,523	ttm_recon	13,538
Sum of reportable segment profit	subtotal	13,538	ttm_recon	13,538
Corporate and Eliminations	corporate_unallocated	(1,509)	ttm_recon	12,029
Consolidated segment profit metric	subtotal	12,029	ttm_recon	12,029
Reverse financing expenses to reach earnings before financing expenses and income taxes	operating	1,636	ttm_recon	13,665
Statutory operating income	statutory subtotal	13,665	ttm_recon	13,665
Financing expenses	other_non_operating	(1,636)	ttm_recon	12,029
Pretax income	statutory subtotal	12,029	ttm_recon	12,029
Income tax expense	tax	(3,102)	ttm_recon	8,927
Net income	statutory subtotal	8,927	ttm_recon	8,927

Reconciliation residuals preserved from the sealed packet: segment sum 0; corporate bridge 0; operating-income bridge 0; pretax bridge 0; net-income bridge 0. Disclosed rounding unit and tolerance are both CAD 1 million. TTM uses non-overlapping Q3 2025, Q4 2025, Q1 2026 and Q2 2026.

Historical bridge line	FY value	TTM value	Forecast treatment	Driver and source	Bear / base / bull rule
Corporate and Eliminations	(677)	(1,509)	Independently forecast corporate/unallocated expense	Exact segment-note line; investigate FX and central-cost mix, D-FS25 and D-Q2-26	Use separately sourced expense assumptions; never plug to consolidated profit
Reverse financing expenses to reach earnings before financing expenses and income taxes	1,080	1,636	Mechanical reclassification only	Must equal the opposite of financing expense in the same period	All cases mechanically equal financing expense reversal; no independent economics
Financing expenses	(1,080)	(1,636)	Interest-rate/debt schedule	Debt, lease and FX components from official FS; current debt anchor 9,853 at Q2 2026	Vary debt and rate assumptions independently; retain below-line classification
Income tax expense	(2,030)	(3,102)	Tax-rate schedule	Effective statutory rate was 25.54% in FY2025 and 25.79% TTM	Apply case tax rate to pretax income; do not combine with operating adjustments

STATUTORY_BRIDGE_STATUS: VERIFIED â€” CLEARED FOR FORECASTING

4. Product and sub-segment historicals

These are the most granular dollar disclosures in the official revenue-from-contracts note. They are customer-revenue/product lines and are not additional reportable segments. No product dollars were taken from FMP because both live product endpoints were empty.

Segment	Product	What it is	Dollar disclosure?	Last three years revenue and source
Oil Sands	Synthetic crude oil and diesel	Upgraded Oil Sands products sold to customers	Yes	FY2023 18.817B; FY2024 19.336B; FY2025 17.803B; D-FS23 and D-FS25 revenue note
Oil Sands	Bitumen	Non-upgraded Oil Sands product sold to customers	Yes	FY2023 7.218B; FY2024 9.924B; FY2025 9.521B; D-FS23 and D-FS25
Exploration and Production	Crude oil and natural gas liquids	Canada and international crude/NGL customer revenue	Yes	FY2023 2.683B; FY2024 2.798B; FY2025 2.509B; D-FS23 and D-FS25

Segment	Product	What it is	Dollar disclosure?	Last three years revenue and source
Exploration and Production	Natural gas	Separately shown only in older product note	Partial	FY2023 0.006B; not separately shown in FY2024-FY2025 product note; D-FS23 and D-FS25
Refining and Marketing	Gasoline	Gasoline customer revenue	Yes	FY2023 13.106B; FY2024 13.357B; FY2025 13.208B; D-FS23 and D-FS25
Refining and Marketing	Distillate	Diesel, jet and related distillate customer revenue	Yes	FY2023 15.283B; FY2024 15.181B; FY2025 14.886B; D-FS23 and D-FS25
Refining and Marketing	Other	Other refined products and marketing revenue	Yes	FY2023 2.679B; FY2024 2.803B; FY2025 2.577B; D-FS23 and D-FS25

The customer-revenue product table differs from reportable-segment gross revenue because intersegment revenues are eliminated in Corporate and Eliminations. For example, FY2025 customer revenue before eliminations was Oil Sands 27.324B, E&P 2.509B, and R&M 30.671B; Corporate and Eliminations of (8.127)B yielded consolidated gross revenue of 52.377B. The Section 3 segment tables preserve the issuer's segment-statement gross-revenue values, not the product-note totals.

Segment	Product	Disclosure method	Last four quarters YoY growth	Source
All segments	No growth-only revenue product identified	Absolute customer-revenue dollars are disclosed for the principal product families above	Not applicable	Q3 2025-Q2 2026 FS revenue notes and live-empty FMP product endpoints

Operational product volumes such as upgraded SCO, bitumen, gasoline, distillate, and other refined-product sales are disclosed, but they are operating KPIs rather than growth-only revenue disclosures. No back-solved product dollars are used.

5. Most recent quarterly trend

Suncor's FY ends December 31. Most recently completed fiscal quarter at time of writing: FY2026 Q2, covering April-June 2026, reported on 2026-08-04 via the official Suncor Q2 report at `https://www.suncor.com/-/media/project/suncor/files/investor-centre/quarterly-reports-2026/2026-q2-suncor-energy-quarterly-report-en.pdf`.

The margin below is the issuer's exact `Earnings (loss) before income taxes` divided by gross revenue. It is not operating margin.

Oil Sands quarter	Gross revenue, CAD B	YoY percent	Exact pretax-margin percent	Source
Q3 FY2025	4.822	(5.1)	34.0	D-Q3-25 FS, reported 2025-11-04
Q4 FY2025	4.680	(14.6)	23.9	D-FS25 / D-Q4-25, reported 2026-02-03
Q1 FY2026	5.335	6.9	28.4	D-Q1-26 FS, reported 2026-05-05
Q2 FY2026	6.051	25.9	44.5	D-Q2-26 FS, reported 2026-08-04

Exploration and Production quarter	Gross revenue, CAD B	YoY percent	Exact pretax-margin percent	Source
Q3 FY2025	0.665	(7.4)	21.4	D-Q3-25 FS
Q4 FY2025	0.450	(29.9)	13.6	D-FS25 / D-Q4-25
Q1 FY2026	0.961	31.8	39.8	D-Q1-26 FS
Q2 FY2026	1.147	72.5	40.5	D-Q2-26 FS

Refining and Marketing quarter	Gross revenue, CAD B	YoY percent	Exact pretax-margin percent	Source
Q3 FY2025	8.077	(0.3)	10.9	D-Q3-25 FS
Q4 FY2025	7.603	0.9	11.8	D-FS25 / D-Q4-25

Refining and Marketing quarter	Gross revenue, CAD B	YoY percent	Exact pretax-margin percent	Source
Q1 FY2026	9.126	19.9	18.1	D-Q1-26 FS
Q2 FY2026	11.811	62.3	17.8	D-Q2-26 FS; live SEC source: https://www.sec.gov/Archives/edgar/data/311337/000110465926090544/su-20260804xex99d2.htm

Quarter	Total upstream production, mboe/d	YoY percent	Refinery throughput, mbbls/d	YoY percent	Refined product sales, mbbls/d	YoY percent	Source
Q3 FY2025	870.0	5.0	491.7	0.8	646.8	5.6	D-Q3-25 MD&A
Q4 FY2025	909.0	3.9	504.2	3.7	640.4	4.4	D-Q4-25 report
Q1 FY2026	875.2	2.6	497.8	3.1	680.9	12.6	D-Q1-26 MD&A
Q2 FY2026	760.9	(5.8)	470.6	6.4	654.8	9.0	D-Q2-26 MD&A

The Q2 upstream decline reflects major maintenance and extraordinary wet weather; the official report estimated a 50,000-60,000 bbls/d weather impact. Q2 Oil Sands cash costs rose to 32.70/bbl, Fort Hills to 44.50/bbl and Syncrude to 40.15/bbl, while refinery operating expense was 6.35/bbl and margin capture was 89%.

6. Management commentary on forward growth

All quotations below are short, source-verifiable excerpts. Fiscal period and actual call date are both shown. Longer management themes are paraphrased to avoid implying precision beyond the source language.

Oil Sands

- Q3 FY2025 call, 2025-11-05 â€” Rich Kruger, CEO: **â€œhigher volumes, lower unit costs.â€■** Topic: operating leverage. Source: D-TR-Q3-25, live FMP transcript dated 2025-11-05.
- Q4 FY2025 call, 2026-02-04 â€” Rich Kruger, CEO: **â€œgrowth from within.â€■** Topic: debottlenecking without major acquisitions. Source: D-TR-Q4-25.
- Q4 FY2025 call, 2026-02-04 â€” Rich Kruger, CEO: **â€œWe can invest and replace production decline, perhaps even grow it.â€■** Topic: sustaining/growth capital. Source: D-TR-Q4-25.
- Q1 FY2026 call, 2026-05-06 â€” Rich Kruger, CEO: **â€œanother 100,000 barrels a day of upstream production growth.â€■** Topic: three-year Investor Day commitment. Source: D-TR-Q1-26 official transcript.
- Q2 FY2026 call, 2026-08-05 â€” Rich Kruger, CEO: **â€œextending Plant 93 and 94â€™s next turnaround cycle to five years.â€■** Topic: Firebag maintenance cadence. Source: D-TR-Q2-26 official and FMP transcripts.

Management also described Fort Hills stream-day capacity near 220,000 bbls/d and a path from 175,000 bbls/d annual production in 2025 toward 200,000 in 2028, the North Pit opening, modular In Situ development south of Firebag/east of Base Plant, and an Investor Day resource claim of roughly 7 billion barrels of 2P reserves and 30 billion barrels of contingent resources. These are management targets/context, not independent reserve estimates.

Exploration and Production

- Q3 FY2025 call, 2025-11-05 â€” Rich Kruger, CEO: **â€œa year-on-year-on-year capital expenditure at less than $6 billion a year.â€■** Topic: capital discipline across the project slate, in response to a question about West White Rose. Source: D-TR-Q3-25, live FMP transcript dated 2025-11-05. The prior draft's West White Rose wording came from analyst Doug Leggate's question and was removed rather than attributed to management.
- Q1 FY2026 call, 2026-05-06 â€” Troy Little, CFO: **â€œmaintaining capital discipline.â€■** Topic: phased development and shareholder returns. Source: D-TR-Q1-26.
- Q2 FY2026 report, 2026-08-04 â€” official MD&A: West White Rose was **â€œnearing completion.â€■** Topic: project pipeline. Source: D-Q2-26.

Direct segment-specific forward commentary for E&P was materially thinner than for Oil Sands and R&M. The official capital schedule continued to identify West White Rose plus development drilling at Hebron and Hibernia; E&P quarterly production rose to 70.8 mboe/d in Q2 2026 from 59.7 a year earlier. Libya remains politically exposed and Syria remains indefinitely suspended.

Refining and Marketing

- Q3 FY2025 call, 2025-11-05 â€” Dave Oldreive, EVP Downstream: **â€œplanning on a five-year interval going forward.â€** Topic: turnaround cadence. Source: D-TR-Q3-25.
- Q4 FY2025 call, 2026-02-04 â€” Dave Oldreive, EVP Downstream: **â€œselling through the optimal channels.â€** Topic: margin capture and product mix. Source: D-TR-Q4-25.
- Q1 FY2026 call, 2026-05-06 â€” Dave Oldreive, EVP Downstream: **â€œa 16,000 barrels a day diesel yield increase.â€** Topic: Edmonton low-cost optimization. Source: D-TR-Q1-26.
- Q2 FY2026 call, 2026-08-05 â€” Dave Oldreive, EVP Downstream: **â€œcontinue to grow diesel production preferentially over gasoline.â€** Topic: product-slate optimization. Source: D-TR-Q2-26.

Management emphasized integration, logistics, export optionality, retail-channel growth, and high secondary-unit utilization. Q2 2026 product sales reached 654.8 mbbls/d, the eighth consecutive quarter above 600 mbbls/d; management said 56 cargoes were exported in H1 2026 versus 58 in all FY2025.

Consolidated, capital allocation, and breakeven

- Q4 FY2025 call, 2026-02-04 â€” Troy Little, CFO: **â€œa WTI breakeven in the low 40s.â€** Topic: resilience. Source: D-TR-Q4-25.
- Q1 FY2026 call, 2026-05-06 â€” Rich Kruger, CEO: **â€œa further $5 a barrel reduction in enterprise breakeven.â€** Topic: three-year target. Source: D-TR-Q1-26.
- Q2 FY2026 call, 2026-08-05 â€” Troy Little, CFO: **â€œ$500 million a month buyback.â€** Topic: ratable capital return. Source: D-TR-Q2-26.

The March 31, 2026 Investor Day framed an additional 100,000 bbls/d of upstream production, a further US$5/bbl enterprise-breakeven reduction, and C$2 billion of incremental annual free funds flow over three years. These are management commitments, not this data package's forecasts.

7. Capital allocation history

`n/s` means not separately disclosed. FMP reports zero R&D expense because Suncor presents technology and development spending within other operating/capital lines; zero is not treated as evidence of no research activity. M&A is the signed FMP `acquisitionsNet` field; negative values are cash outflows and positive values are net inflows/vendor-classified recoveries.

Year	Capex, CAD B	Capex / FMP revenue, percent	R&D, CAD B	R&D / revenue, percent	Buybacks, CAD B	Dividends, CAD B	M&A signed, CAD B	Source
FY2021	4.555	11.64	n/s	n/s	2.304	1.550	0.335	D-FMP-CFA; official MD&A
FY2022	5.120	8.78	n/s	n/s	5.135	2.596	0.315	D-FMP-CFA; official MD&A
FY2023	5.828	11.87	n/s	n/s	2.233	2.749	(0.512)	D-FMP-CFA; official MD&A
FY2024	6.483	12.79	n/s	n/s	2.908	2.803	0.051	D-FMP-CFA; official MD&A
FY2025	5.856	11.97	n/s	n/s	3.129	2.809	0.066	D-FMP-CFA; official MD&A

FY2025 MD&A defined 3.162B of asset sustainment/maintenance and 2.496B of economic investment, excluding 0.198B of capitalized interest. In H1 2026 Suncor spent 2.466B including capitalized interest, paid 1.418B of dividends, and repurchased 1.875B of common shares.

8. Balance sheet snapshot

The FY2025 debt perimeter uses the issuer's debt excluding leases because it reconciles directly to issuer net debt. Lease liabilities were a further 4.517B. FMP `totalDebt` was 18.383B and does not align to the issuer's net-debt definition, so it is not substituted.

Item	CAD B	Source
Cash and equivalents	3.650	D-FS25; D-FMP-BA
Short-term investments	0.000	D-FMP-BA; no material official amount
Total debt, current plus long-term excluding leases	9.987	D-FS25 / FY2025 MD&A net-debt bridge
Net debt	6.337	D-FS25 / FY2025 MD&A
Net debt / EBITDA	0.91x	D-FMP-KMA live standardized metric
Goodwill plus intangibles	3.455	D-FMP-BA; official balance-sheet classification
Tangible book value	41.669	45.124 equity less 3.455 goodwill/intangibles

At Q2 2026, cash was 5.372B, debt excluding leases was 9.853B, net debt was 4.481B, and lease liabilities were 4.827B. Available credit facilities were 5.307B. Issuer-defined net debt to trailing adjusted funds from operations was 0.3x; total debt to total debt plus equity was 17.0%.

9. Recent corporate actions

- **2025-10-14:** Suncor announced the retirement of CFO Kris Smith; subsequent calls identify Troy Little as CFO. Source: official Suncor leadership release D-CA-CFO and Q4 2025/Q1 2026 calls.
- **2025-11-06:** Suncor announced a C$1.0B medium-term note offering; the Q4 call described two- and five-year tranches. Source: official Suncor news-release index and D-TR-Q4-25.
- **2026-02-26:** Suncor filed annual disclosure documents and renewed its normal-course issuer bid. Source: official Suncor news-release index and FY2025 40-F package.
- **2026-03-31:** Suncor published the 2026 Investor Day plan and a contingent-resources report, raising three-year operating/free-cash-flow ambitions. Source: D-ID26 and official news release.
- **2026-08-04/05:** Suncor reported Q2 results and raised the ongoing buyback pace to C$500M per month, subject to market conditions and authorization. Source: D-Q2-26 and D-TR-Q2-26.
- **H1 2026:** Suncor repaid 378M of long-term debt and reduced issuer net debt to 4.481B. Source: D-Q2-26 FS and MD&A.

No material corporate acquisition closed in the searched last-twelve-month source set. The prominent business changes were operating-project progress, balance-sheet deleveraging, the CFO transition, Investor Day targets, and higher share repurchases.

10. Open data gaps and source register

Gap classification	Dataset / issue	Sources and search terms checked	Treatment
True non-disclosure	Volumetric commodity hedge book and explicit contract-coverage percentage	FY2025 FS Note 29; Q2 2026 MD&A; risk management, derivative, hedge, contract coverage	Gross/net derivative fair values disclosed; no invented hedge volume
True non-disclosure	Consistent issuer-calculated annual reserve replacement ratio	FY2021-FY2025 AIF; replacement, reserves additions, depletion, reserve life	Net 2P history and calculated approximate life shown; no replacement series inferred
True non-disclosure	Standalone R&D expense	FY2021-FY2025 FS/MD&A; live FMP income statements; research, development, technology, R&D	Capital/operating lines retained; R&D marked n/s, not zero economics
True non-disclosure	Project-level breakeven for every pipeline project	AIFs, annual/quarterly MD&A, Investor Day; breakeven, capital cost, project economics	Company-level and selected portfolio targets preserved only
True non-disclosure	Full Q2 2026 decommissioning-provision roll-forward	Q2 2026 FS/MD&A; decommissioning, restoration, provision	FY2025 provision and H1 cash settlements shown
Estimated	Approximate reserve life	Net 2P reserves divided by annual production	Clearly labeled calculation; not issuer RLI

Gap classification	Dataset / issue	Sources and search terms checked	Treatment
Not fetched / omitted	None material	All mandatory commodity/energy families searched	No known official material table deliberately omitted
Not applicable	P&C ownership perimeter	Suncor is not an insurer	Section 0b omitted

Live source register

Source ID	Type / period	Live URL or endpoint	D archive / freshness
D-FMP-IA	FMP annual income, FY2018-FY2025	`https://financialmodelingprep.com/stable/income-statement?symbol=SU.TO&period=annual`	`raw\pulse-cio-20260906T220342+0800\d\fmp_income_annual_live.json`; live 2026-09-06
D-FMP-IQ	FMP quarterly income	`https://financialmodelingprep.com/stable/income-statement?symbol=SU.TO&period=quarter`	`d\fmp_income_quarter_live.json`; live 2026-09-06
D-FMP-BA	FMP annual balance sheet	`https://financialmodelingprep.com/stable/balance-sheet-statement?symbol=SU.TO&period=annual`	`d\fmp_balance_annual_live.json`; live 2026-09-06
D-FMP-CFA	FMP annual cash flow	`https://financialmodelingprep.com/stable/cash-flow-statement?symbol=SU.TO&period=annual`	`d\fmp_cashflow_annual_live.json`; live 2026-09-06
D-FMP-KMA	FMP annual key metrics/ratios	`https://financialmodelingprep.com/stable/key-metrics?symbol=SU.TO&period=annual`	`d\fmp_keymetrics_annual_live.json`; live 2026-09-06
D-FMP-PA/PQ	FMP product segmentation	`/stable/revenue-product-segmentation?symbol=SU.TO&period=annual` and `period=quarter`	Both live files are exact empty arrays
D-FS21 through D-FS25	Official audited FS, FY2021-FY2025	SEC EDGAR 40-F exhibits for CIK 311337	`d\sec_2021_fs_live.html` through `d\sec_2025_fs_live.html`; live 2026-09-06
D-MD&A21 through D-MD&A25	Official annual MD&A	SEC EDGAR 40-F exhibits	`d\sec_2021_mda_live.html` through `d\sec_2025_mda_live.html`; live 2026-09-06
D-AIF21 through D-AIF25	Official AIF/reserves	SEC EDGAR 40-F exhibits	`d\sec_2021_aif_live.html` through `d\sec_2025_aif_live.html`; live 2026-09-06
D-Q3-25	Official Q3 report/FS/MD&A	`https://www.sec.gov/Archives/edgar/data/311337/000110465925106443/`	`d\sec_2025_q3_fs_live.html`; `d\sec_2025_q3_mda_live.html`
D-Q4-25	Official Q4/annual report	`https://www.suncor.com/-/media/project/suncor/files/investor-centre/quarterly-reports-2025/2025-q4-suncor-energy-quarterly-report-en.pdf`	Browser-live 2026-09-06; direct identical Suncor PDF fetch failed HTTP 403
D-Q1-26	Official Q1 FS/MD&A	`https://www.sec.gov/Archives/edgar/data/311337/000110465926055745/`	`d\sec_2026_q1_fs_live.html`; `d\sec_2026_q1_mda_live.html`
D-Q2-26	Official Q2 FS/MD&A	`https://www.sec.gov/Archives/edgar/data/311337/000110465926090544/`	`d\sec_2026_q2_fs_live.html`; `d\sec_2026_q2_mda_live.html`
D-TR-Q3-25	Earnings-call transcript, 2025-11-05	FMP live plus official Suncor transcript URL	`d\fmp_transcript_2025_q3_live.json`; date verified
D-TR-Q4-25	Earnings-call transcript, 2026-02-04	FMP live	`d\fmp_transcript_2025_q4_live.json`; date verified
D-TR-Q1-26	Earnings-call transcript, 2026-05-06	Official Suncor IR transcript	Browser-live 2026-09-06; FMP endpoint empty on identical retry
D-TR-Q2-26	Earnings-call transcript, 2026-08-05	FMP live plus official Suncor transcript	`d\fmp_transcript_2026_q2_live.json`; date verified
D-ID26	Investor Day, 2026-03-31	`https://www.suncor.com/en-ca/investors/investor-day-march-2026`	Official page/deck browser-live 2026-09-06
D-CA-CFO	CFO retirement, 2025-10-14	Official Suncor news release	Browser-live 2026-09-06

Mandatory self-checks

- Largest FY2025 segment revenue: Refining and Marketing at 30.569B, 58.36% of official gross revenue. The latest quarter showed 11.811B of segment gross revenue, up 62.3% year on year, confirmed against the live Q2 2026 official segment statement.
- Quote check: the Q1 FY2026 CEO commitment to **â€œanother 100,000 barrels a day of upstream production growthâ€■** appears in the official transcript dated 2026-05-06, one day after the May 5 results release and within the required 30-day window.
- FY2025 revenue check: live FMP annual income statement reports 48.908B, tying the official operating-revenue-net-of-royalties line; official gross revenue is 52.377B and controls segment composition. The 7.1% gross-to-net difference is disclosed rather than silently overwritten.
- Both FMP product endpoints were fetched live and returned exact empty arrays. Official product/segment tables replace them without fabricated values.
- Both statutory periods, every sealed segment line, bridge label, classification, value, source ID, currency and scale are reproduced above. The expected bridge SHA is unchanged.

Data-package conclusion: the official disclosure inventory is complete enough for DR review. The only material gaps are true non-disclosures or explicitly identified method/perimeter boundaries; no statutory-bridge blocker remains.