SPHEREX INSIGHTS | ENERGY FINANCE ANALYTICAL & RESEARCH NOTE

The Stabroek Block Petroleum Fiscal Regime

An applied analysis of financing, cost recovery, ring-fencing, production depletion, government petroleum receipts and exploration implications

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Author: Joel Bhagwandin

ANALYTICAL RESEARCH NOTE | PETROLEUM FISCAL REGIME, FIELD ECONOMICS AND DEPLETION OUTLOOK

CENTRAL THESIS: The Stabroek Block petroleum fiscal regime must be assessed across its contractual cost-recovery architecture, financing provisions, ring-fencing treatment, production profile and long-run revenue implications. The base case is a 1.3mn bpd reserve-constrained production path that reaches peak output in 2028, holds the cap while new developments offset decline, and falls materially after 2040 as the remaining resource base depletes. Over 2027–2051, Government petroleum receipts total USD 186.4bn and the real NRF balance reaches USD 109.6bn by 2051. Internal operating cash flow remains the base-case financing architecture because it avoids explicit recoverable financing charges and accelerates the transition from cost oil to profit oil. External debt remains a liquidity tool, not a free source of capital: recoverable interest and fees total USD 5.6bn and defer Guyana receipts by USD 2.8bn over the first 15 years. Government captures 35.7% of gross revenue over the 25-year horizon; a stylized 50%-of-gross regime would add USD 74.5bn. The projected depletion profile also creates an exploration imperative: Government should accelerate exploration activity and begin preparing a fresh competitive auction round for new offshore blocks so that the next discovery cycle can advance before Stabroek's decline materially narrows the petroleum-revenue base.

Prepared by SphereX Professional Services Inc.

Georgetown, Guyana | Analytical and research note

Supporting quantitative framework: Stabroek Financing and NRF Outlook, 2027–2051.

Key Insights

The analysis is structured around a 25-year production and revenue horizon, a reserve-constrained 1.3mn bpd production cap, explicit post-plateau decline curves and an opportunity-cost comparison between current PSA receipts, a 50%-of-gross counterfactual, NRF/Treasury returns and potential upstream reinvestment.

■ **Operating cash flow protects the public rent baseline.** Where development is funded from operating cash flow and no recoverable financing charge enters the cost bank, more post-royalty revenue converts into profit oil sooner.

■ **Debt cost is fiscal, not merely private.** Even though the contractor raises the capital, recoverable interest, fees and related charges can enlarge the cost bank and reduce or defer the State's share of profit oil.

■ **Rising global capital costs sharpen the rent issue.** Higher base rates, wider credit spreads, refinancing risk and carbon-transition premiums increase the probability that external funding becomes a larger recoverable charge against future petroleum revenues.

■ **The base case is a reserve-constrained screening case, not an open-ended acceleration case.** The selected screening production path peaks at 1.3mn bpd in 2028, remains capped through 2040 while new developments offset field decline, and then falls to about 114 kbpd by 2051 as the 9.8bn bbl remaining resource base approaches depletion.

■ **The 25-year public-receipts screening baseline is USD 186.4bn.** Under the internal-finance base-case screening, Guyana receives USD 186.4bn in royalty and profit oil over 2027–2051, with cumulative Treasury transfers of USD 105.6bn and a 2051 real NRF balance of USD 109.6bn under the statutory prior-year petroleum-revenue withdrawal basis.

■ **Opportunity cost is explicit.** The current PSA produces an effective 25-year Government take of 35.7% of gross revenue. A mechanical 50%-of-gross counterfactual would add USD 74.5bn, or about USD 3.0bn per year, but this remains a fiscal-regime benchmark rather than a recommendation because investment behaviour, sanction timing and resource delivery are not endogenously modelled.

■ **Ring-fencing is not mechanically good or bad.** IMF guidance recognizes the balance: absence can postpone early Government revenue, while an overly restrictive fence can weaken exploration and development incentives. The delay case is a sensitivity, not a prediction.

■ **The screening decline curve changes the fiscal reading.** At the 1.3mn bpd screening cap, production remains flat at approximately 474.5mn barrels per year from 2028 through 2040, then declines sharply: average production falls to about 1.13mn bpd in 2041, 783 kbpd in 2046 and 114 kbpd by 2051, with screening depletion reached in 2054 under the current field schedules and 7% post-plateau decline assumption.

■ **Resource replacement is an exploration imperative.** Optimization can extend the lower-rate tail of production, but it cannot replace exhausted barrels. Government should therefore accelerate exploration across available acreage and give early attention to preparing another transparent, competitive offshore bid round for new blocks. The objective should be to widen the exploration frontier and advance the next cycle of commercial discoveries before the present production base enters structural decline, while respecting existing licence terms, retained acreage and contractual rights.

FISCAL-REGIME IMPLICATION: Financing, ring-fencing, cost recovery, depletion and resource replacement interact within one petroleum fiscal regime. Internal self-funding remains the base-case architecture; external debt must be benchmarked because recoverable interest and fees can defer Guyana receipts; ring-fencing should be assessed by its timing, liquidity and development-response effects; and the decline curve makes exploration and resource replacement central to the durability of the petroleum-revenue base. Government should intensify exploration, accelerate work programmes where commercially and technically justified, and prepare a fresh competitive auction round for new offshore blocks before the current production plateau gives way to sustained decline.

Executive Analytical Assessment

> **CENTRAL FINDING:** The Stabroek Block PSA operates as a block-wide petroleum fiscal regime in which eligible costs are recovered before the residual profit oil is shared. The principal analytical test is whether financing charges, ring-fencing arrangements and the pace of production alter the timing and present value of Guyana's petroleum receipts. Interest and fees admitted to the cost bank can reduce or defer Guyana's share of profit oil and economic rent; faster production brings receipts forward, raises near-term NRF deposits and Treasury-transfer potential, and accelerates depletion of the finite recoverable-resource base. The resulting decline curve makes exploration-led resource replacement integral to the long-run durability of the fiscal regime.

The core analytical question is no longer confined to who finances the remaining Stabroek developments. Article 11.1 places the obligation to bear and pay Contract Costs on the Contractor, so the State is not required to raise capital for the development programme. The petroleum fiscal-regime question is broader: whether contractor financing costs enter recoverable cost, whether ring-fencing affects the timing of profit oil, and how the accelerated production path alters Government receipts, NRF accumulation and the timing of resource depletion.

The central proposition is therefore a petroleum fiscal-regime proposition, not a narrow funding proposition. Internal cash is not economically free, and debt may be rational for the co-venturers. But where financing costs are recoverable, the capital structure affects cost oil, profit oil, NRF deposits and Treasury-transfer capacity. Accelerated production improves the timing of receipts but also increases depletion pressure, placing greater importance on resource replacement and the continuity of the petroleum-revenue base.

This is why Annex C section 3.1(l) is not merely a technical accounting clause. It links the contractor's capital-structure decision to Guyana's fiscal timing. The IHS Markit audit confirmed that the clause permits recovery of market-consistent interest, expenses and related financing fees, while reporting that no such costs had been included through Q4 2017. If admitted to cost recovery, those charges are recovered through cost oil before profit oil is calculated. In a contract area without field-level ring-fencing, a financing charge associated with one development can therefore reduce or defer the profit-oil pool available for Government sharing across the wider Stabroek portfolio.

The production profile establishes the principal boundary condition. Of the approximately 11bn boe Stabroek resource screening envelope, about 1.2bn boe had been produced before 2026. The reserve-constrained base case reaches 1.3mn bpd in 2028, maintains approximately 474.5mn barrels of annual production through 2040 as new developments offset field decline, and then falls sharply to about 1.13mn bpd in 2041, 783 kbpd in 2046 and 114 kbpd by 2051. Full depletion occurs in 2054 under the current field schedules and 7% post-plateau decline assumption. Optimization can stretch the lower-rate tail, but it cannot replace exhausted barrels.

The fiscal implication is that revenue capacity must not be confused with spending capacity. Accelerated production can enlarge near-term petroleum receipts, but public investment must still pass tests of absorptive capacity, inflation control, exchange-rate management, procurement quality and project-execution discipline. Peak-period revenues should therefore be treated as a temporary national balance-sheet opportunity: save through the NRF, stabilize the macroeconomy, fund productivity-enhancing non-oil assets and avoid building permanent recurrent expenditure on a finite production surge.

Resource replacement is therefore an immediate petroleum-sector priority. The projected decline requires Government to accelerate exploration activity across prospective acreage, sharpen the pace and accountability of existing exploration work programmes, and begin preparing another transparent and competitive auction round for new offshore blocks. Early preparation is essential because licensing, seismic acquisition, exploration drilling, appraisal and development sanction require long lead times.

A fresh bid round should be advanced before decline becomes entrenched, with fiscal terms, data quality, relinquishment rules, work commitments and investor qualification designed to attract credible exploration capital while protecting Guyana’s long-term economic interest.

The executive conclusion is integrated. Financing-cost control protects the profit-oil pool; calibrated ring-fencing analysis protects the timing and value of public rent; accelerated production brings receipts forward but shortens the high-output window; and exploration-led resource replacement protects the continuity of Guyana’s petroleum-revenue base. These are interconnected features of the Stabroek Block petroleum fiscal regime rather than separate technical questions.

What the model says

Exhibit 1. Base-case model outputs and decision implications.

■ Production scale

1.3mn bpd

Peak production reached in 2028 under the selected base case.

◆ Government receipts

USD 186.4bn

Projected 2027–2051 royalty plus profit oil under the internal-finance base case.

● 2051 NRF balance

USD 109.6bn

Constant-2026-dollar closing balance under the statutory prior-year-revenue withdrawal basis.

▲ Ring fence timing

+USD 3.5bn NPV

Same-schedule project ring fence shifts receipts forward over the full model horizon, with a broadly offsetting contractor equity-FCF NPV impact.

■ Delay sensitivity

USD 182.7bn

2027–2051 receipts under a two-year post-2026 delay; timing losses are concentrated around the plateau and early decline years.

◆ Financing charge

USD 5.6bn

Recoverable interest plus fees under the modelled 60% debt-funded development-capex case; associated 15-year Guyana receipt deferral is USD 2.8bn.

Values are presented in constant 2026 USD unless otherwise stated. Totals are rounded. Supporting calculations and reconciliation checks are maintained in the quantitative framework.

Analytical Brief

Analytical implications for public policy

1. The 2016 Petroleum Agreement remains the governing contractual framework for production licenses issued under it while at least one relevant prospecting or production licence remains in force.
2. The contractor, not the State, is responsible for funding petroleum operations. Under that architecture, project debt, guarantees or NRF capital for the co-venturers' development programme would sit outside the State's contractual funding role.
3. Operating cash flow remains the default development-funding source in the analytical base case because it minimizes explicit financing costs and avoids adding recoverable interest and fees to the cost bank.
4. The absence of project ring-fencing forms part of that financing architecture: it supports sequential self-funding, while creating a near-term fiscal timing effect that is analytically relevant for tracking and disclosure.
5. External financing is analytically supportable only where it demonstrably protects schedule, liquidity or risk resilience and where its pricing, related-party status, allocation and recoverability are independently tested.
6. The contractual conclusion has an analytical boundary: a discovery before the end of exploration does not, by that fact alone, prove an unconditional right to develop every accumulation. Commerciality, appraisal, retained acreage, application timing, development-plan approval and a production licence remain relevant.

What does not follow from the evidence

- It does not follow that internal funds have zero cost. They carry a sponsor-level opportunity cost.
- It does not follow that all external financing is prohibitively expensive. ExxonMobil, Chevron and CNOOC have strong balance sheets and multiple capital-market channels.
- It does not follow that the announced 11bn boe is equivalent to 11bn barrels of proved, developed and producing oil reserves.
- It does not follow that the paper's 10-hub screening construct is sanctioned. Seven Stabroek developments are currently government-sanctioned; Longtail, the eighth identified development, is under regulatory review, while the final two hubs in the model are explicit screening constructs.
- It does not follow that the 2027 exploration-expiry date can be established from the 2016 Agreement alone. The base term in Article 3 is four years plus two possible three-year renewals from the Effective Date; any further extension or adjustment must be evidenced by the operative licence or amendment.

Exhibit 2. The financing question changes depending on whose cost is being optimized.

■ Internal cash flow	◆ External debt	● Analytical conclusion
Uses retained project cash and avoids explicit lender charges, while carrying sponsor-level opportunity cost.	Can preserve liquidity and support sponsor capital allocation, but may defer receipts where interest and fees enter the cost bank.	The public-revenue test is whether financing costs change the timing and present value of Guyana's receipts.

1. The Contractual Answer

1.1 The PSA survives exploration expiry where production licenses remain

Article 29.1 is the decisive continuity provision. It provides that the Agreement is deemed terminated only when the Petroleum Prospecting Licence and every Petroleum Production Licence have expired, been surrendered or been lawfully cancelled. Article 8.9 permits an application to renew a production licence for up to ten years where the contractor is in good standing. The published Whiptail production licence was granted for 20 years and expressly references the 2016 Petroleum Agreement.

> **CONTRACTUAL CONCLUSION:** Expiry of the exploration limb does not extinguish an existing production licence or the PSA while another qualifying licence remains alive. The fiscal terms continue to govern production operations licensed under that agreement.

1.2 Discovery is not the same as an approved development

Article 8 establishes a sequence: notice of discovery; assessment of potential commercial interest; an appraisal programme; an application for a Petroleum Production Licence accompanied by a Development Plan; ministerial review; and grant of the production licence where the requirements are met and the contractor is not in default. Article 8.3 also allows the Minister to extend the time for a production-licence application following appraisal.

Accordingly, the safest formulation is not that every discovery made by an assumed 2027 cut-off is automatically and indefinitely developable on the 2016 terms. The stronger and better-supported formulation is that production licenses granted under the 2016 Agreement are governed by it, and that qualifying discoveries may progress under Article 8 subject to the operative prospecting licence, retained acreage, statutory requirements, application timing and approved development plan.

1.3 Evidence required before a categorical legal conclusion

Document / record	Question to close	Why it matters
Current Stabroek prospecting licence	Exact expiry, renewal phase, extensions and relinquishments	The 2016 Agreement alone does not establish a 2027 expiry.
Bridging Deed / amendments	Treatment of 1999 operations and later amendments	Confirms continuity and any modified rights.
Discovery notices and appraisal status	Which accumulations have met Articles 8.1-8.3	A discovery headline is not a development right.
Development applications	Filed before relevant statutory/contractual deadlines	Protects project pathway after exploration expiry.
Production licenses	Area, term, conditions and renewal status	Defines the operating right and duration.

This note interprets the available contractual materials for financial-advisory purposes. Formal counsel confirmation of the operative licence record remains necessary.

2. How the Financing Mechanism Works

2.1 Contractor funding obligation

Article 11.1 requires the Contractor to bear and pay all Contract Costs and recover eligible amounts only through Cost Oil and Cost Gas. This is the answer to the public-sector financing question: the Government is not contractually required to capitalize the projects. Project funding is a co-venturer responsibility.

2.2 The PSA waterfall

1. Royalty: 2% of petroleum produced and sold, subject to the contract's measurement provisions.
2. Cost oil: eligible recoverable costs, limited monthly to 75% of the relevant post-royalty revenue in the model, consistent with the Evercore waterfall.
3. Profit oil: the residual after cost oil.
4. Profit split: 50% Government and 50% Contractor.
5. Carry-forward: eligible costs not recovered within the monthly ceiling remain in the cost bank for later recovery.

At the full 75% cost-oil ceiling, Guyana's immediate cash share is approximately 14.25% of gross revenue in the model: 2% royalty plus one-half of the 25% residual after the royalty-adjusted cost-oil allocation. That is the low-watermark waterfall outcome while the cost ceiling binds. Once the historical cost bank no longer binds, current-period costs rather than the ceiling determine cost oil; the residual profit-oil pool expands and Guyana's effective cash take rises materially above the 14.25% floor. The 30%–40% range is therefore best treated as a conservative transition band, not a hard ceiling. In the base case, higher output delivers improved economies of scale, lowering the effective breakeven and unit operating-cost burden after development costs are recovered, allowing Government take to exceed 40% at current prices while contractor operating margins also improve. The qualification is material: if oil prices fall sharply, the same fixed and semi-fixed cost base absorbs more revenue through cost oil and the effective take can move back toward the lower part of the range.

2.3 Financing cost is not outside the fiscal system

Annex C section 3.1(l) includes interest, expenses and related fees on loans raised for Petroleum Operations, provided the costs are consistent with market rates. This makes financing cost part of the fiscal system. If interest expense or financing fees are admitted to cost recovery, they enlarge the cost bank and are recovered before profit oil is calculated. The effect is explicit: every additional recoverable financing dollar can reduce or defer the profit-oil pool, and therefore reduce or delay the Government's share of profit oil, NRF deposits and Treasury transfers. The clause does not make every asserted charge automatically valid; allocation, market consistency, purpose, affiliate terms and audit evidence remain material.

Exhibit 3. Illustrative external-financing chain under the base case.

Source: SphereX analytical model. Pending development capex after 2025 totals USD 40.7bn in the scenario; 60% is debt-funded at 7.25% plus a 1% fee.

1. Debt-funded capex	→	2. Finance charges	→	3. Cost bank effect	→	4. Receipt timing
60% of pending capex funded externally.		Interest and fees enter only where contractual tests are met.		Recoverable interest and fees enlarge the cost bank and are deducted through cost oil before profit oil is calculated.		A smaller or later profit-oil pool defers Government receipts relative to internal funding.

3. Is Internal Finance the Optimum?

> **FINDING:** Yes, as the default funding architecture from a system-cost and Guyana-revenue perspective; not as an absolute corporate-finance theorem.

3.1 Why it is the lowest-friction base case

- No debt coupon, arranger fee, commitment fee, refinancing charge or security package is required.
- No lender covenant can delay a development, restrict distributions or force hedging at an unfavorable point in the oil-price cycle.
- Where no financing charge is entered into the cost bank, more post-royalty revenue becomes profit oil sooner.
- The Stabroek portfolio is already producing at scale, so funding is generated in the same US-dollar revenue stream in which development obligations are incurred.
- Recycling cash across a non-ring-fenced contract area matches the economic architecture already described by Evercore and the cost-recovery audit.

3.2 Why "internal finance is always cheaper" is too broad

Retained cash belongs to the investors and has an opportunity cost. If the co-venturers can borrow below their risk-adjusted return on alternative projects, debt can improve sponsor-level value even after fees. Debt also preserves liquidity for dividends, share repurchases, acquisitions, low-carbon investments and downside buffers. In the model, the external-finance case produces a positive contractor equity-FCF NPV delta of approximately USD 1.8bn because debt advances 60% of development capex and financing costs are partly recovered through the PSA.

That private benefit is not proof of lower system cost. It reflects timing, risk allocation and fiscal sharing. The model adds approximately USD 5.6bn of interest and fees to recoverable cost and defers about USD 2.8bn of Guyana receipts over the first 15 years. The private and public optima can therefore diverge.

3.3 Opportunity-cost matrix

Exhibit 4. Opportunity-cost matrix for internal cash flow versus external debt.

■ Internal cash-flow advantage	◆ Debt-financing advantage
Lowest explicit funding cost; no coupon, arranger fee, refinancing charge or imputed financing cost enters the base-case cost bank.	Preserves sponsor liquidity and risk capacity; may be privately rational where borrowing cost is below the contractor's opportunity cost of cash.
● Guyana timing value	**▲ Governance burden**
Internal funding accelerates profit oil where no recoverable financing cost is added; external debt can defer receipts while charges are recovered.	Debt financing requires stronger controls over pricing, allocation, related-party terms, recoverability and audit evidence.

4. Ring-Fencing: Revenue Timing Versus Development Pace

> **CORE FINDING:** No project ring fence supports the operating-cash-flow financing model, but it also permits costs from later developments to reduce profit oil generated by producing projects. The economic question is whether the value of faster development exceeds the present value of the receipts deferred.

4.1 What ring-fencing changes

A ring fence is a fiscal boundary within which revenues and costs may be consolidated. The 2016 Stabroek PSA operates at the Contract Area level rather than imposing a separate cost-recovery pool around each development. Consequently, eligible exploration, development, operating and financing costs from one project may affect cost oil and profit oil across the wider block, subject to the contractual ceiling and audit rules.

IMF guidance identifies both sides of the design trade-off. Without a restrictive fence, new-project expenditure can be deducted or recovered against producing assets, postponing Government revenue. A tight project fence can protect early receipts and level the field for new entrants, but may also reduce exploration and development by delaying cost recovery. The appropriate design therefore balances modest earlier revenue against potentially greater or earlier production over time.

4.2 The financing channel

Exhibit 5. Financing-channel comparison under block-wide and project-level ring-fencing.

■ Block-wide recovery structure

Later-project costs can be recovered against wider Contract Area production, allowing contractor cash to be replenished sooner and recycled into the next FPSO.

Analytical effect: stronger sequential self-funding, lower reliance on debt, but potential near-term profit-oil deferral.

◆ Project-level ring-fence structure

Each development recovers costs only from its own production, creating clearer project allocation while delaying cost recovery until the individual field generates sufficient revenue.

Analytical effect: earlier receipts from producing fields, but greater bridging-liquidity pressure and more complex shared-cost administration.

The absence of project ring-fencing is best understood as a development-financing incentive because it supports rapid sequential investment from operating cash flow. The proposition is strongest when framed as a financing mechanism rather than a slogan. The scale of any delay depends on contractor liquidity, sponsor funding, project economics, sanction discipline and access to debt; it cannot be inferred from the ring fence alone.

4.3 What the model shows

Exhibit 6. Government-receipt profile under alternative project ring-fence cases.

Source: SphereX analytical model. The same-schedule case isolates cost allocation; the delay case shifts production and capital expenditure by two years for developments starting from 2027.

Fiscal metric	No project ring fence	Ring fence: same schedule	Ring fence: 2-year delay
Government receipts, 2027–2051	USD 186.4bn	USD 183.5bn	USD 182.7bn
Government receipts NPV, 2027–2051	USD 81.5bn	USD 82.4bn	USD 82.0bn
Government receipts NPV, 2026–2065	USD 84.8bn	USD 88.3bn	USD 88.0bn
Contractor equity-FCF NPV, 2026–2065	USD 83.7bn	USD 80.1bn	USD 81.1bn
Peak production	1.30mn bpd / 2028	1.30mn bpd / 2028	1.30mn bpd / 2030
2041 net NRF balance | real 2026 USD	USD 83.9bn	USD 83.9bn	USD 81.6bn
Treasury transfers, 2027–2041 | real 2026 USD	USD 67.8bn	USD 68.7bn	USD 68.4bn

The same-schedule case isolates the pure timing effect. Nominal Government receipts converge over the 2026–2065 model horizon, but project-level ring-fencing shifts receipts forward and raises Government-receipts NPV by approximately USD 3.5bn while reducing contractor equity-FCF NPV by a similar amount. Within the 2027–2051 fiscal horizon, nominal receipts are lower because some field-level cost recovery extends beyond the reporting window.

The two-year-delay case is an illustrative sensitivity rather than a forecast. Relative to the no-ring-fence case, Government receipts over 2027–2051 are lower by approximately USD 3.7bn, while Government-receipts NPV is about USD 0.5bn higher over that horizon because the shifted production profile interacts with the 1.3mn bpd cap. By 2041, the real NRF balance is approximately USD 2.3bn lower. The result is therefore principally a timing, capacity and liquidity effect; it is not evidence of a proven permanent loss of recoverable barrels.

> **INTERPRETATION: Ring**-fencing can improve the timing of Government take if development is unchanged. It can destroy value if it materially delays otherwise commercial production. The analytical outcome turns on the development response, which must be tested rather than assumed.

4.4 Analytical treatment under the existing PSA

This analytical and research note does not assume that Government can impose a new project ring fence unilaterally on existing production licenses. The PSA, licence terms, stability provisions and applicable law require formal legal review. For current Stabroek operations, the analytically relevant response is preservation of the block's self-funding capacity with project-level sub-ledgers, audited cost allocation, advance review of financing charges, development-specific payout reporting and transparent disclosure of the profit-oil timing effect.

For future petroleum contracts, Government can evaluate a calibrated fence rather than a binary choice: licence-level consolidation with development-specific reporting; limits on cross-project recovery after payout; separate treatment of financing costs; or transitional rules that preserve exploration incentives while protecting receipts from mature fields.

5. Global Capital Markets and Climate Risk

5.1 The base-rate environment remains materially above the pre-tightening era

The global cost of capital is central to the public-rent question. The Federal Reserve maintained the federal funds target range at 3.50%–3.75% on 29 July 2026, effective 30 July 2026, while the Bank of Guyana's June 2026 NRF report noted a 4.42% US 10-year Treasury yield at quarter-end. These benchmarks are not the borrowing cost for Stabroek, but they establish that external capital begins from a materially positive risk-free base before project, tenor, commodity, country, covenant and transition-risk spreads are added.

Higher-for-longer rates matter because recoverable financing costs can divert petroleum revenue from profit oil into cost recovery. The IMF's July 2026 update raised projected global headline inflation to 4.7% and described stalled disinflation. The World Bank's June 2026 outlook linked the Middle East energy shock to steeper inflation and higher borrowing costs, with bond yields and foreign-currency spreads elevated for exposed emerging markets. For Guyana, the implication is straightforward: if external debt is used, its pricing and recoverability must be tested as a fiscal-value issue, not merely as a contractor financing choice.

5.2 Rising global capital costs and the fiscal transmission channel

The rising cost of global capital affects Guyana even where the State does not borrow a dollar for the developments. Under a recoverable-cost PSA, the financing cost borne by the Contractor becomes a fiscal variable when interest expense, fees, refinancing charges or related credit costs are admitted to the cost bank. The transmission is direct: higher all-in funding cost increases recoverable cost; recoverable interest expense is deducted through cost oil before profit oil is determined; a larger cost-oil claim reduces or defers the profit-oil pool; lower or later profit oil reduces NRF deposits and alters the timing of Treasury transfers.

This is the core rent-transmission issue. A project loan that is commercially reasonable for the co-venturers may still reduce Guyana's near-term public take if its coupon, fees or refinancing costs are recoverable ahead of profit oil. In practical terms, interest expense is not only a contractor cost; once admitted to cost recovery, it becomes a deduction from the petroleum revenue available for profit-oil sharing. The correct policy test is therefore whether the financing structure preserves or diminishes the present value of the economic rent accruing to the national fiscal framework.

The relevant pricing stack includes the risk-free base rate, tenor premium, upstream project spread, country and legal-risk adjustments, commodity-price volatility, reserve and execution risk, lender covenant package, refinancing exposure and climate-transition premium. In a higher-for-longer rate environment, each layer can increase the all-in cost of capital and make external debt less neutral from Guyana's fiscal perspective.

> **FISCAL TRANSMISSION:** Higher global capital costs do not affect Guyana only through public borrowing. They affect Guyana through the PSA cost-recovery channel whenever interest expense, fees or refinancing charges are recoverable. Those charges are recovered through cost oil before profit oil is calculated, reducing or deferring the profit-oil pool available for Government sharing.

5.3 Climate transition risk is increasingly present in credit pricing

BIS research on syndicated loans finds that a carbon premium became statistically apparent after the Paris Agreement, especially for direct Scope 1 emissions. A Basel Committee literature review also records higher loan pricing for fossil-fuel firms in settings with more stringent policy exposure and notes reduced lending to higher-emitting firms in some datasets. The evidence supports a direction of travel; it does not establish a single universal oil-and-gas spread.

5.4 Oil-market transition risk affects both price and terminal value

The IEA's latest available medium-term oil outlook, Oil 2025, projects demand growth slowing toward a plateau around 105.5mn bpd by 2030, while production capacity grows more quickly. The IEA's scenarios are not certainties and OPEC publishes more demand-supportive long-run views. The bankable conclusion is therefore not that oil demand will collapse, but that price, utilization and terminal-value risk increase as the project horizon extends.

> **ANALYTICAL IMPLICATION:** A rising global cost of capital makes the financing channel more important for Guyana, not less. A recoverable coupon, fee or refinancing charge can reduce the economic rent converted into profit oil. The policy priority is therefore capital discipline, market benchmarking, rapid payback, emissions-risk control and conservative terminal assumptions.

Exhibit 7. Climate-transition and capital-market risk channels.

● Inflation and base rates

Higher nominal coupons and refinancing cost; the model uses a 7.25% all-in debt case.

◆ Carbon policy and lender appetite

Carbon premiums and policy exposure can affect spreads; emissions pathway evidence remains relevant.

▲ Demand substitution and terminal value

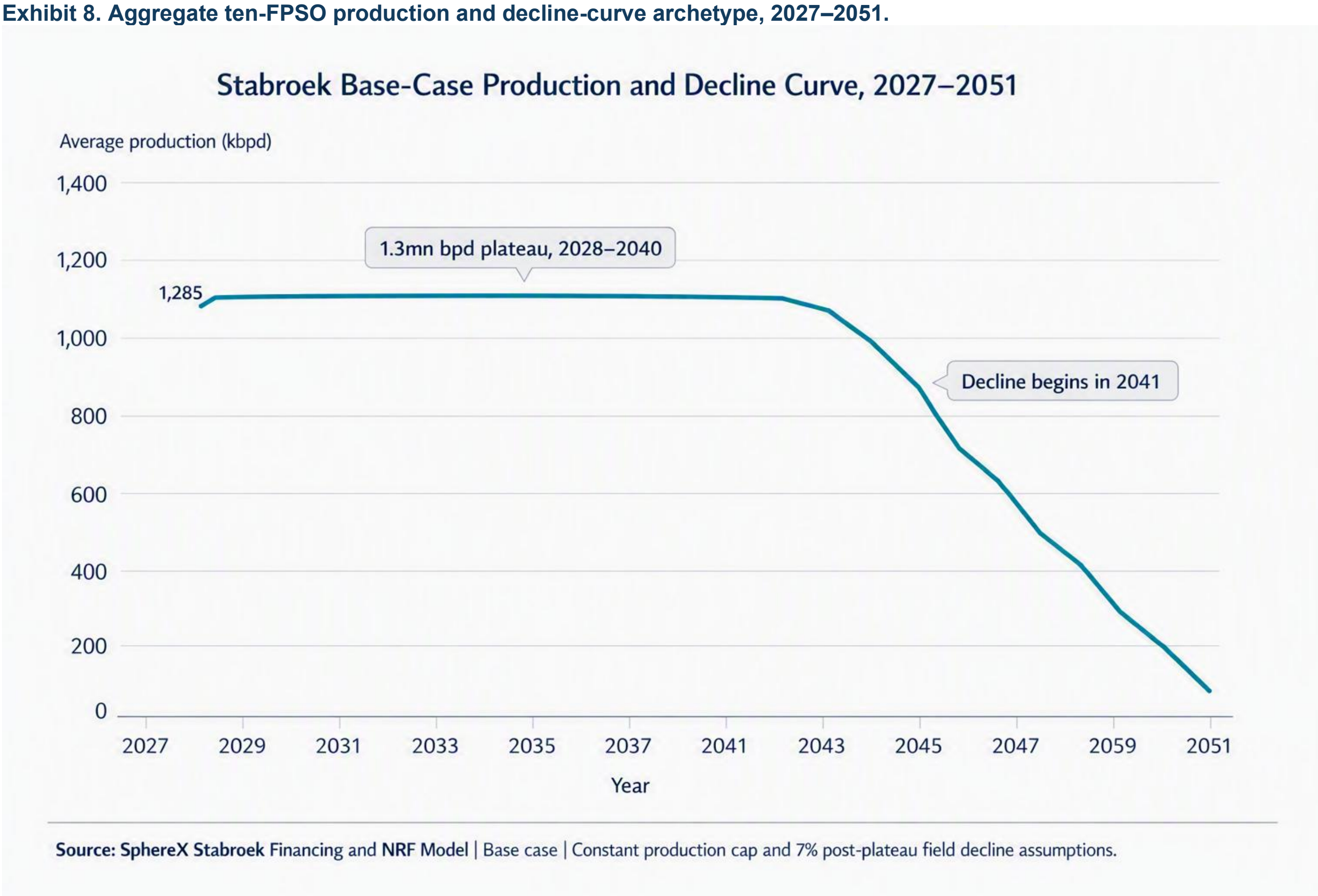
Long-run price, utilization and terminal-value risk increase as the project horizon extends.

■ Physical climate and decommissioning

Insurance, spill response, continuity planning and abandonment funding remain material diligence areas.

6. Ten-FPSO Production and Depletion Archetype

Exhibit 8. Aggregate ten-FPSO production and decline-curve archetype, 2027–2051.



Source: SphereX Stabroek Financing and NRF Model. Base case; actual annual series, 2027–2051.

Source: SphereX analytical model. Eight identified developments plus two illustrative later hubs; production constrained to the 11bn boe analytical screening envelope.

■ Ten-hub screening archetype

2.16mn bpd

Total nameplate capacity across eight identified developments and two illustrative later hubs.

◆ Peak production

1.3mn bpd

Reached in 2028 and maintained through 2040 before field decline dominates.

● 2027–2051 output

~9.32bn barrels

Cumulative production over the 2027–2051 forecast horizon, following approximately 0.38bn barrels produced in 2026.

The production archetype uses ten development hubs with total nameplate capacity of 2.16mn bpd, while the base case is capped at 1.3mn bpd and constrained by the remaining 9.8bn bbl resource base. Production reaches the cap in 2028 and remains at approximately 474.5mn barrels per year through 2040 as new developments offset decline in earlier fields. The decline curve becomes decisive after 2040: average production falls to about 1.13mn bpd in 2041, 1.05mn bpd in 2042, 783 kbpd in 2046, 593 kbpd in 2047 and 114 kbpd by 2051. The resource base is fully depleted in 2054 under the current field schedules and 7% post-plateau decline assumption. The high-output plateau therefore creates a substantial but finite fiscal window. This trajectory warrants an accelerated national exploration programme and early preparation of another competitive offshore auction round so that new acreage can be licensed, explored and appraised before petroleum receipts narrow structurally.

> **DEPLETION INTERPRETATION:** The high-rate production window is finite. Optimization, infill drilling and improved recovery can flatten decline and extend the lower-rate tail, but they do not replace exhausted barrels. The production profile must therefore be assessed alongside exploration activity, acreage management and the timely replacement of commercial resources before the present Stabroek production base enters maturity.

The analytical implication is accelerated resource replacement. Government should intensify exploration across prospective acreage and give immediate attention to structuring a fresh, transparent and competitive auction round for new offshore blocks. The purpose is not to interrupt existing developments, but to shorten the interval between licensing, seismic work, drilling, appraisal and the next commercial sanction. Given the long lead time from bid round to first production, the next exploration cycle should begin well before Stabroek’s current plateau gives way to sustained decline.

6.1 Development assumptions

Exhibit 9. Development assumptions used in the ten-FPSO production archetype.

Development hub	Start year	Nameplate capacity	Modelled resource allocation	Status / treatment in model
Liza Destiny	2019	160 kbpd	0.90bn boe	Producing / publicly identified
Liza Unity	2022	250 kbpd	1.20bn boe	Producing / publicly identified
Prosperity (Payara)	2023	250 kbpd	1.20bn boe	Producing / publicly identified
ONE GUYANA (Yellowtail)	2025	250 kbpd	1.30bn boe	Producing / publicly identified
Errea Wittu (Uaru)	2026	250 kbpd	1.30bn boe	Approved / reported timing
Jaguar (Whiptail)	2027	250 kbpd	1.30bn boe	Approved / publicly identified
Hammerhead	2029	150 kbpd	0.70bn boe	Sanctioned / publicly identified
Longtail	2030	200 kbpd	1.00bn boe	Identified / modelling assumption
Future Hub A	2032	200 kbpd	1.00bn boe	Illustrative, not sanctioned
Future Hub B	2034	200 kbpd	1.10bn boe	Illustrative, not sanctioned

The 11bn boe envelope is allocated for analytical screening purposes. It is not a field reserve booking or an operator development plan.

6.2 Why this is not a geological or reservoir model

Public information is insufficient to construct a defensible full-field dynamic simulation. The model applies first-year ramp, plateau and 7% annual decline archetypes, capped by an allocated remaining-resource balance. A bankable depletion plan would require seismic interpretation, depth conversion, petrophysical cut-offs, contacts and fluid properties; static and dynamic model ensembles; well-test and pressure data; aquifer and injection behaviour; completion and uptime assumptions; water and gas handling constraints; and uncertainty distributions for STOIIP, recovery factor and recoverable reserves.

7. Field Economics and Government Petroleum Receipts

7.1 Base-case assumptions

Exhibit 10. Base-case field-economics assumptions.

■ Price and revenue path

USD 60/bbl in 2026, declining by 1% real annually to a USD 55 floor; conservative mid-cycle path, not a forecast. At current-price levels, higher output after cost recovery creates improved economies of scale, lowers unit breakeven and raises the residual profit-oil pool; downside price cases test how quickly that advantage narrows.

◆ Cost-bank starting point

USD 4.5bn opening cost bank at 1 January 2026, based on Evercore estimate and treated as unaudited.

● Field-cost assumptions

USD 10/bbl cash operating cost, USD 2/bbl sustaining capex and USD 1.50/bbl abandonment accrual as screening inputs.

Breakeven interpretation is volume-sensitive: the prior Stabroek performance analysis placed production breakeven near USD 21.7/bbl and 2025 IFRS operating-cost intensity near USD 18.8/bbl. As output expands over largely installed infrastructure and legacy development costs are recovered, improved economies of scale reduce unit cost intensity, increasing the profit-oil pool at current prices. This relationship should be disclosed as a model assumption and stress-tested against lower oil-price paths.

■ PSA and investment inputs

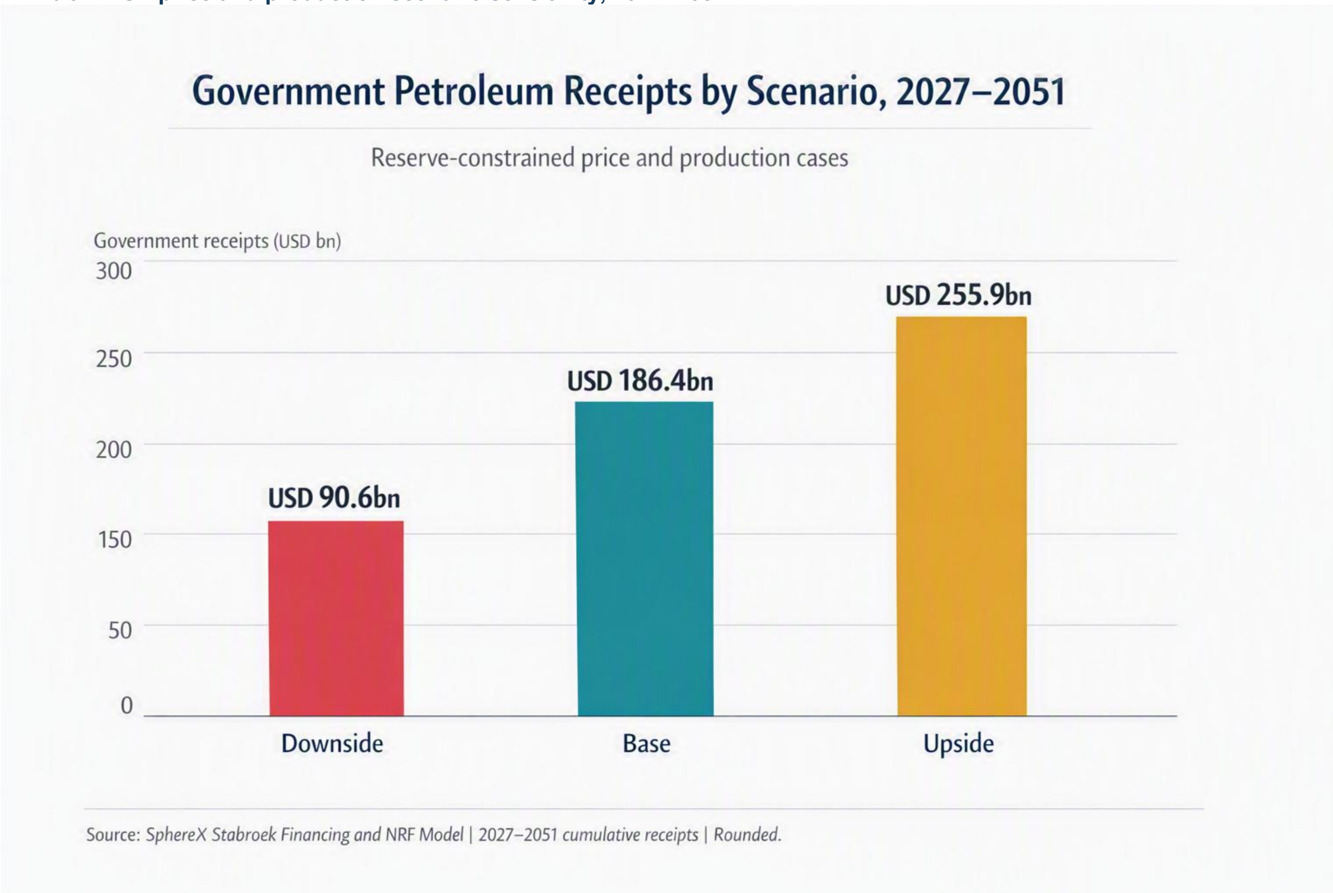
2% royalty, 75% cost-oil ceiling, 50/50 profit oil, USD 40.7bn pending capex after 2025 and 8% real screening discount rate.

7.2 Cost-bank transition

The opening cost bank is fully recovered in the model during 2026 because production, price and cost-oil capacity are high relative to the carried balance. Thereafter, current-period development and operating costs are recovered without rebuilding a persistent bank in the internal-finance case. Government take consequently rises from approximately 18% of gross revenue in 2026 toward and, at current prices, beyond 40% as the cost bank desaturates and output expands. The mechanism is straightforward: higher production spreads fixed and semi-fixed operating costs across more barrels, lowers effective breakeven and operating-cost intensity, and leaves a larger residual profit-oil pool for 50:50 sharing after royalty and cost oil. This result is directionally consistent with the Stabroek performance analysis, which placed production breakeven near USD 21.7/bbl and 2025 IFRS operating-cost intensity near USD 18.8/bbl, although the exact timing depends on audited cost, lift timing, realized prices and capex phasing.

7.3 Price sensitivity

Exhibit 11. Oil-price and production scenario sensitivity, 2027–2051.



Source: SphereX Stabroek Financing and NRF Model. Cumulative Government petroleum receipts, 2027–2051; rounded.

Source: SphereX analytical model. NPV discounted at 8%; production and field-cost assumptions held constant.

Scenario	25-year gross revenue	25-year Government receipts	Government receipts NPV	2051 annual Government take
Downside	USD 319.5bn	USD 90.6bn	USD 34.6bn	34.1%
Base	USD 521.8bn	USD 186.4bn	USD 88.1bn	38.7%
Upside	USD 658.3bn	USD 255.9bn	USD 132.4bn	41.4%

Government take is lower in the downside case because a larger share of a smaller revenue pool is required to recover fixed and semi-fixed costs. Conversely, at current or firmer prices, expanded production after recovery of historic development costs creates improved economies of scale, lowers the effective breakeven and allows Government take to rise above 40%. The sensitivity therefore operates through price, output and the cost-oil/profit-oil mix. Oil price remains the dominant fiscal risk; financing cost is material, but it is second-order relative to the commodity cycle.

8. Natural Resource Fund Outlook

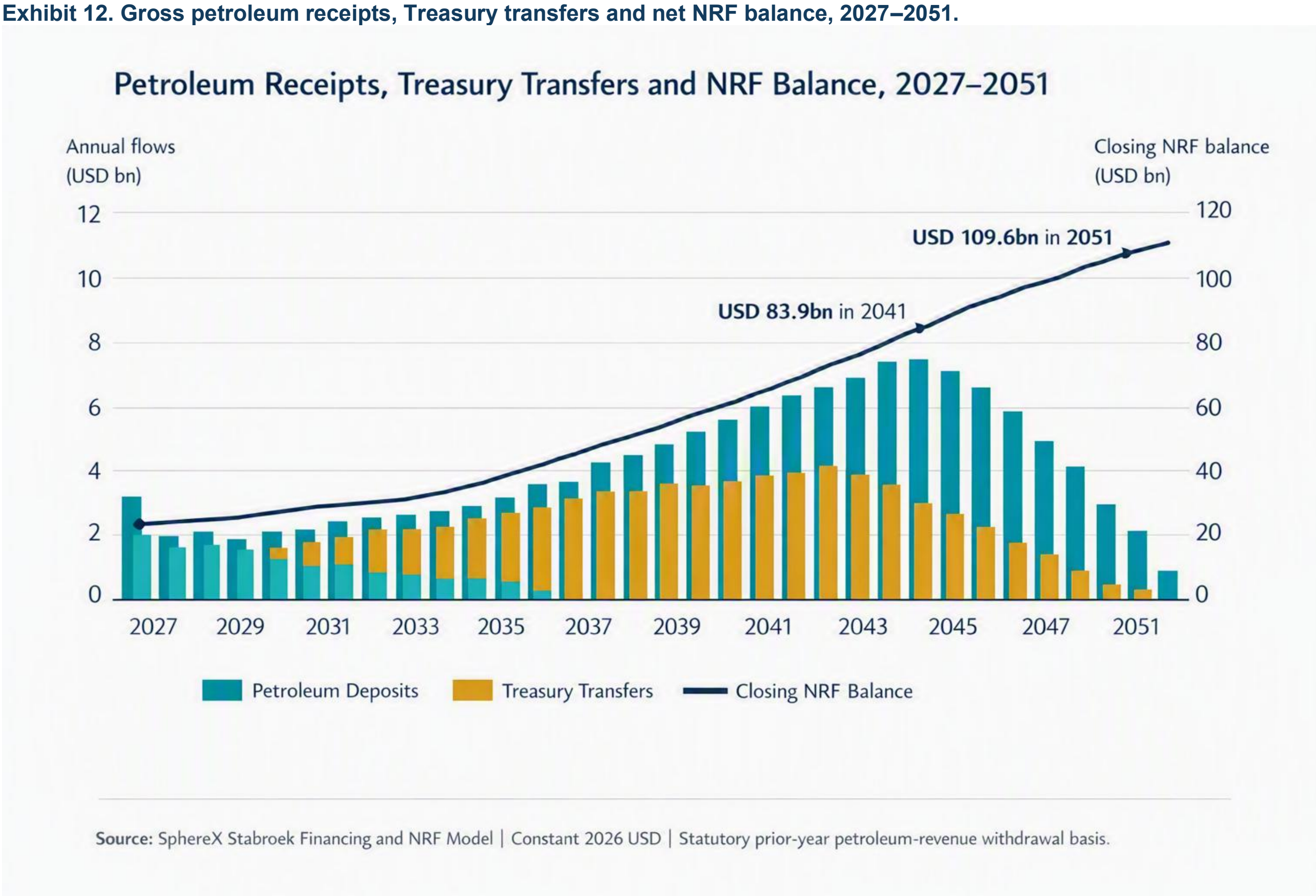
8.1 Base-year evidence

The Bank of Guyana reported an NRF market value of USD 4.294bn at 30 June 2026, Q2 inflows of USD 1.235bn, and cumulative inflows since inception of USD 9.168bn from profit oil, USD 1.335bn from royalties and USD 15mn from signature bonus. The 2026 Budget authorized a maximum transfer of approximately USD 2.374bn.

8.2 Forecast mechanics

The forecast begins from the reported 1 January 2026 opening balance of approximately USD 3.435bn, uses 2026 Government receipts and deducts the authorized 2026 withdrawal. For consistency with the constant-2026-dollar framework, the 3.5% nominal portfolio-return assumption is converted to an annual real return of approximately 1.47% using a 2.0% USD inflation assumption. From 2027, the base case applies the amended marginal bands to petroleum revenues paid into the Fund in the immediately preceding fiscal year. An opening-balance formulation is retained only as a non-statutory sensitivity. Policy withdrawal is set at 100% of the calculated ceiling and deducted annually.

Exhibit 12. Gross petroleum receipts, Treasury transfers and net NRF balance, 2027–2051.



Source: SphereX Stabroek Financing and NRF Model. Constant 2026 USD; statutory prior-year petroleum-revenue withdrawal basis.

Source: SphereX analytical model. The NRF line is the constant-2026-dollar closing balance after annual transfers, using the statutory prior-year-petroleum-revenue basis, an approximately 1.47% real portfolio return and 100% utilization of the calculated ceiling.

NRF indicator	2027	2030	2035	2041	2051
Petroleum deposits	USD 8.0bn	USD 7.9bn	USD 10.1bn	USD 8.8bn	USD 0.9bn
Transfer to Treasury	USD 3.0bn	USD 4.5bn	USD 4.7bn	USD 4.7bn	USD 1.7bn
Net retained in year	USD 5.1bn	USD 3.8bn	USD 6.1bn	USD 5.3bn	USD 0.8bn
Closing NRF balance	USD 9.5bn	USD 20.9bn	USD 46.9bn	USD 83.9bn	USD 109.6bn
Cumulative deposits	USD 8.0bn	USD 32.2bn	USD 78.6bn	USD 137.9bn	USD 186.4bn
Cumulative Treasury transfers	USD 3.0bn	USD 16.6bn	USD 39.5bn	USD 67.8bn	USD 105.6bn

By 2051, cumulative gross petroleum receipts reach USD 186.4bn, cumulative Treasury transfers reach USD 105.6bn, and the real closing NRF balance reaches USD 109.6bn.

The statutory prior-year-revenue basis is the reported base case. An opening-balance formulation is retained only as a non-statutory sensitivity to isolate how the choice of calculation base changes the fiscal path. The legal ceiling still establishes a maximum, not an automatic appropriation: any transfer remains subject to the annual budget and parliamentary process.

The projection is not a recommendation to spend the statutory maximum. Petroleum revenue capacity is not the same as public-investment absorption capacity. Asset allocation, domestic inflation, exchange-rate management, project execution, intergenerational saving and debt strategy require an integrated fiscal framework before higher annual transfers can be treated as development capacity.

Accelerated production should therefore tighten, not loosen, fiscal discipline. A faster production ramp improves the timing of petroleum receipts, but those receipts remain temporary and resource-dependent. The fiscal framework should avoid converting peak-period oil revenues into permanent recurrent obligations. The stronger use of the high-output period is to save a meaningful share through the NRF, preserve macroeconomic stability, and channel budget transfers into productivity-enhancing capital formation where execution capacity is demonstrably available.

The correct fiscal distinction is between revenue capacity and absorptive capacity. Higher oil receipts expand the budget envelope, but they do not automatically expand the economy's ability to absorb spending without inflation, exchange-rate pressure, construction bottlenecks, labour scarcity or weak project execution. The high-rate window should therefore be used to build non-oil wealth, including infrastructure, energy reliability, drainage and climate resilience, human capital, digital systems, public-sector execution capacity and private-sector competitiveness.

9. Petroleum Revenue Opportunity Cost and Capital Allocation

The opportunity-cost analysis distinguishes three separate questions: how much petroleum revenue Guyana receives under the current PSA, how a mechanical 50%-of-gross counterfactual would change receipts, and how NRF holdings compare with higher-risk upstream reinvestment. Over 2027–2051, the current PSA produces USD 186.4bn of Government receipts against USD 521.8bn of gross revenue, equivalent to a 35.7% effective take. A stylized 50%-of-gross regime would produce USD 260.9bn, implying incremental capture of USD 74.5bn, or about USD 3.0bn per year on average.

Opportunity-cost metric	Model output	Interpretation
Current PSA receipts, 2027–2051	USD 186.4bn	Baseline public take under the internal-finance case.
Current effective take	35.7%	Share of gross revenue captured through royalty and profit oil.
50%-of-gross counterfactual	USD 260.9bn	Mechanical fiscal-regime benchmark, not an investment-behaviour forecast.
Incremental fiscal capture	USD 74.5bn	Average annual uplift of approximately USD 3.0bn.
NRF/Treasury benchmark	4.0% nominal / 2.0% real	Low-risk benchmark for liquidity, stabilization and intergenerational savings.
Upstream base return proxy	14.5% real	Higher-risk return derived from illustrative Future Hub cash flows and dependent on additional commercial resources.

The opportunity-cost result does not imply that Guyana should replace the NRF with upstream reinvestment or mechanically pursue a 50%-of-gross fiscal regime. It clarifies the trade-off. NRF/Treasury assets are liquid, stabilizing and low-risk; upstream reinvestment is illiquid, execution-intensive and commercially uncertain, but potentially higher-return if additional resources exist and governance is strong.

The correct policy frame is therefore portfolio discipline: protect the NRF's stabilization function, test any proposed reinvestment against commercial resource evidence, and avoid confusing fiscal capture with sustainable development capacity.

10. Analytical Findings and Governance Implications

10.1 Internal-cash-flow presumption as the analytical base case

Under the existing Stabroek Block PSA, approved Petroleum Operations are funded by the Contractor and recovered through the Contract Area cost-recovery mechanism. The analytical base case is therefore not simply a funding preference; it is a public-rent protection baseline. Any external financing or ring-fence adjustment must be assessed against its effect on recoverable cost, profit oil, NRF deposits, Treasury transfers, development timing and the present value of Guyana's receipts.

10.2 Financing-cost protocol as an analytical control requirement

1. Advance notice: financing-cost recoverability is strongest where the Contractor discloses, before booking any charge for recovery, the lender, borrower, purpose, amount, tenor, pricing, fees, security and affiliate relationship.
2. Market test: the analytical standard compares base rate, margin, fees, hedging and covenant package against comparable investment-grade upstream financings and the sponsors' own borrowing curves.

3. Least-cost test: the proposed instrument is analytically supportable only if it compares favourably with operating cash, parent funding, partner equity and alternative debt structures on an after-recovery and present-value basis.
4. Allocation test: recoverability is stronger where the borrowing is demonstrably tied to Stabroek Petroleum Operations and is not a parent-level capital-allocation charge or cross-subsidy.
5. Related-party test: recoverability is weaker where arm's-length evidence, beneficial-owner transparency or the elimination of duplicative spreads and fees is not demonstrated.
6. Audit and clawback: transaction-level evidence and recovery of disputed amounts with interest become central controls where charges fail the contractual standard.
7. Public reporting: aggregate financing costs admitted to the cost bank provide the relevant transparency metric, while legitimately confidential pricing detail can remain protected.

10.3 Liquidity and schedule-resilience considerations

The internal-funding base case remains analytically strongest only where it does not undercapitalise operations. The relevant liquidity evidence includes minimum cash and committed-liquidity buffers for operating cost, major maintenance, spill response, abandonment funding and a defined low-price stress. External committed facilities may remain relevant as contingent liquidity without necessarily being drawn or charged in full to the cost bank.

10.4 NRF treatment under the contractor-funding architecture

Under the existing contractor-funding architecture, the NRF is analytically distinct from project-capex financing. Guyana's petroleum revenue flows into the Fund and supports national development through the statutory budget process; it does not replace the Contractor's Article 11 funding obligation, guarantee co-venturer borrowing, or function as a lender to field developments. Such use would concentrate Guyana's public balance sheet further in the same commodity and project risks that generate the Fund.

10.5 Accelerated production, depletion and exploration

Accelerated production brings Guyana's petroleum receipts forward, increasing near-term profit oil, royalty receipts, NRF deposits and statutory transfer potential. The same acceleration shortens the high-output window because the recoverable-resource base is finite. The production profile must therefore be considered together with accelerated exploration capable of replacing commercial resources before decline dominates.

The practical implication is to protect the NRF's stabilization function, avoid treating peak petroleum receipts as permanent, and accelerate exploration before the decline curve becomes binding. Government should advance a coordinated exploration programme that includes stronger execution of existing work commitments and timely preparation of another transparent, competitive auction round for new offshore blocks. Without new commercial discoveries, future NRF deposits and Treasury-transfer capacity will decline as the current production base matures.

11. Conditions Before Further Development

Exhibit 13. Minimum diligence gates before further development reliance.

■ Licence and legal pathway

Current licenses, amendments, discovery notices, application deadlines and production-licence terms determine the confidence level for post-exploration rights.

◆ Reservoir and development evidence

Independent resource review, recovery-factor ranges, dynamic reservoir model, well count, uptime, capex, opex, schedule and abandonment estimates remain the core technical diligence package.

● Cost-bank and financing controls

Audited opening balance, project allocation, recovery timing, instrument terms, parent support, related-party status and hedging terms shape the analytical treatment of recoverability.

■ Market, climate and fiscal capacity

Oil-price stress, carbon exposure, emissions pathway, insurance, decommissioning security, NRF withdrawal policy and investment-absorption capacity define the broader reliance threshold.

11.1 Analytical thresholds

- Internal funding is analytically supported where project economics remain robust at the downside oil-price case and liquidity buffers remain intact.
- External debt is analytically supportable where schedule or resilience value exceeds the present value of recoverable financing cost and no lower-cost alternative exists.
- Financing-cost recovery becomes analytically weak where pricing is not demonstrably market-consistent, allocation is unclear, or affiliate economics are not arm's length.
- Development sanction requires further evidence where reserve deliverability, emissions compliance, decommissioning security or commercial break-even is not independently supported.

12. Conclusion

FINAL ASSESSMENT: The principal issue is not whether Guyana raises capital for the remaining Stabroek developments. The Contractor does. The national issue is whether recoverable financing costs enlarge cost recovery, defer profit oil and reduce the present value of Guyana’s petroleum receipts. Over 2027–2051, internal cash flow remains the preferred public-rent baseline: it supports USD 186.4bn of Government petroleum receipts, cumulative Treasury transfers of USD 105.6bn and a 2051 real NRF balance of USD 109.6bn. External debt may be rational for the co-venturers, but where interest and fees are recoverable, it becomes a petroleum fiscal-regime variable rather than a purely private financing choice.

Internal operating cash flow remains the preferred public-rent baseline because it avoids explicit recoverable debt charges and supports sequential development from the Contract Area’s own US-dollar revenue stream. External debt may be commercially rational for the co-venturers, but from Guyana’s perspective it must be justified by clear evidence that any schedule, liquidity or resilience benefit exceeds the fiscal value lost or deferred when interest expense and fees are recovered before profit oil is calculated.

Ring-fencing should therefore be evaluated through the same public-rent lens. A project-level fence can bring receipts forward if development timing is unchanged, but it can destroy value if it weakens liquidity or delays commercial production. Rising global capital costs sharpen this trade-off because higher base rates, wider spreads and refinancing risk can increase recoverable interest expense, enlarge cost oil and reduce or defer the profit-oil pool. The implication for Guyana is direct: weaker profit-oil timing lowers NRF deposit momentum, affects Treasury-transfer capacity and reduces the present value of the public take unless financing charges are rigorously benchmarked, audited and justified.

The final reading is therefore more favourable than a static Government-take statement would imply. The 30%–40% range captures the transition from a saturated cost bank to a desaturated cost-recovery environment; it should not be treated as a permanent ceiling. Beyond that point, higher production at current prices improves both sides of the ledger through improved economies of scale: it increases the State's residual profit-oil share and raises contractor profitability by reducing unit operating cost. The caveat is commodity-price volatility. If prices weaken materially, or if new recoverable costs rebuild the cost bank, the fiscal upside is compressed because recoverable costs consume a larger portion of revenue before profit oil is split.

The production conclusion is defined by the decline curve. The base case reaches 1.3mn bpd in 2028 and holds that level through 2040, but this plateau is achieved by drawing down a finite resource base. After 2040, decline becomes the dominant consideration: average output falls to about 1.13mn bpd in 2041, 783 kbpd in 2046 and 114 kbpd by 2051, with full depletion reached in 2054 under the current field schedule and 7% post-plateau decline assumption. The response is twofold: preserve the value of petroleum receipts through the NRF and disciplined investment; and accelerate exploration now. Government should give early and serious attention to another competitive offshore licensing round so that new blocks can move through exploration and appraisal before the present production base enters sustained decline.

The financing question, the ring-fencing question, the depletion question and the exploration question therefore converge within the petroleum fiscal regime. Guyana's objective should be to maximize the present value of public rent while preserving development timing, protecting the NRF's stabilization role and avoiding overreliance on a finite production plateau. The opportunity-cost analysis shows that the current PSA captures 35.7% of gross revenue over 2027–2051, while a stylized 50%-of-gross regime would add USD 74.5bn; however, higher Government take, upstream reinvestment or tighter ring-fencing must be tested against investment incentives, additional-resource evidence, contractor liquidity and execution risk. The regime should preserve self-funding where it protects public rent, scrutinize recoverable financing charges, maintain the NRF as the principal savings and stabilization mechanism, accelerate current exploration activity, and prepare another transparent, competitive auction round for new offshore blocks. Resource replacement must begin before Stabroek's decline curve materially narrows the petroleum-revenue base.

13. Model Methodology and Limitations

13.1 Model architecture

The quantitative framework covers assumptions, reserve-constrained production, decline-curve logic, PSA field economics, financing, project ring-fence analysis, the 25-year NRF forecast, Treasury receipts, oil-price and production scenarios, petroleum-revenue opportunity cost, integrity checks and source documentation. The visible forecast period is 2027–2051, with technical tails retained through 2065 for depletion, debt and run-off checks. The base case uses a 1.3mn bpd production cap, an 11.0bn boe gross resource envelope less 1.2bn boe already produced, and field-specific exponential decline after plateau at the current 7% assumption. Reconciliation checks cover the financing roll-forward, statutory NRF withdrawal basis, independent scenario paths, the 25-year receipts tie, the 50% regime bridge and reserve-depletion consistency.

13.2 Financing case

The external case funds 60% of modelled post-2025 development capex with seven-year straight-line debt at 7.25% and a 1% upfront fee. Interest is calculated on average annual debt. Interest and fees enter the external cost bank; principal does not enter a second time because the underlying capex is already recoverable. The internal and external PSA waterfalls are run separately, allowing the Government-receipt timing effect to be isolated.

13.3 Ring-fence case

The project-ring-fence module maintains a separate cost bank for each of the ten modelled developments. The opening USD 4.5bn cost bank is allocated to producing fields in proportion to 2026 production because audited project-level balances were not available for this screening analysis.

The same-schedule case isolates cost allocation. The delayed case shifts capital expenditure, start dates and plateau periods by two years for developments starting from 2027; it is an illustrative sensitivity to test the financing argument, not an endogenous prediction of contractor behaviour.

13.4 Principal limitations

- The opening 2026 cost bank is an Evercore estimate, not an audited Government balance.
- The project allocation of the opening cost bank is an analytical convention and requires replacement with audited development-level cost ledgers.
- Annual calculations approximate a monthly PSA mechanism and do not model individual lift timing, crude differentials, tax barrels or in-kind settlement.
- The model assumes all stated field costs are eligible and ultimately recovered; audit disallowances are not forecast.
- The 11bn boe envelope may include gas and resources that are not ultimately commercial or recoverable. The production module treats it as a liquids-equivalent screening envelope, not a certified recoverable crude-oil forecast.
- Future Hub A and Future Hub B are hypothetical and have no asserted licence, FDP, reserve booking or sanction.
- The depletion-window estimate is a simple screening interpretation of the 11bn boe recoverable-resource envelope less approximately 1.2bn boe already produced, not an operator forecast, reserve certification or reservoir-engineering depletion study.
- The two-year ring-fence delay is an illustrative sensitivity. Actual development timing would depend on sponsor liquidity, project sanction, contractual treatment and capital-market access.
- Capital-expenditure phasing, operating costs, abandonment accrual, plateau duration and decline rates are screening assumptions.
- The NRF projection assumes economic Government receipts equal annual cash deposits; actual lift, payment and crediting dates will differ.
- The reported NRF base case applies the withdrawal bands to prior-year petroleum revenues, consistent with the statutory formulation. The opening-balance method is retained only as a clearly labelled non-statutory sensitivity.
- The above-40% Government-take outcome is conditional on price, volume and improved economies of scale. It assumes current or firmer oil prices, expanded output, substantial recovery of legacy development costs and no sustained rebuilding of the cost bank from new capex, financing charges or audit-approved operating costs.
- The NRF forecast is a constant-2026-dollar fiscal-capacity scenario. It converts the nominal portfolio return to a real rate, applies the current marginal bands mechanically, and does not forecast parliamentary appropriations, future legislative amendments or a transition in asset allocation. No corporate tax, parent-company tax shield, withholding tax, debt covenant, hedging cash flow or co-venturer-specific funding allocation is modelled.
- The high-rate plateau through 2040 and the subsequent decline path are sensitive to field optimization, infill activity, uptime, recovery factor, gas handling, reservoir performance, future discoveries and the timing of any new commercial development.
- The fiscal opportunity-cost module is a policy screening tool. The 50%-of-gross regime is a mechanical counterfactual, and the upstream return proxy is derived from illustrative Future Hub cash flows; neither result models investor behaviour, fiscal negotiation outcomes, reserve-certification risk, sanction probability or macroeconomic absorption constraints.

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SELECTED ABBREVIATIONS

PSA	Petroleum Sharing Agreement	**NRF**	Natural Resource Fund
FPSO	Floating production, storage and offloading vessel	**NPV**	Net present value
FCF	Free cash flow	**boe**	Barrels of oil equivalent
bpd	Barrels per day	**FDP**	Field Development Plan
IMF	International Monetary Fund	**IEA**	International Energy Agency
BIS	Bank for International Settlements	**STOIIP**	Stock-tank oil initially in place

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PUBLICATION AND ADVISORY CONTACT
info@spherexgy.com | +592 652-1995 | www.spherexgy.com
165 Waterloo Street, Regus Building, Georgetown, Guyana

AUTHOR
Joel Bhagwandin
Director | Financial Advisory
jbhagwandin@spherexgy.com | LinkedIn

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