



ENERGY & CLIMATE — INVESTMENT PERSPECTIVE

Venezuela's Oil Rebuild: A Bottom-Up View of Capital and Service Demand

What a return toward 3 million b/d would require—by time horizon, basin, and service line

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Venezuela's oil recovery is being increasingly framed around the \$100 billion associated with the seventeen-field program announced by North American Blue Energy Partners (NABEP). That figure is plausible as an order-of-magnitude signal, but it is not a national rebuild budget. Our bottom-up framework estimates **\$118 to 165 billion for the core oil system** and a separate \$8 to 15 billion offshore-gas track for a total capital envelope of **\$126 to 180 billion, with a mid-case of approximately \$151 billion**. This is a conditional estimate of what a recovery could require, not a forecast of committed spending. It would support an increase from roughly 1.1 million barrels per day (b/d) today to more than 3 million b/d in the central case over a decade or longer.¹

Two assumptions drive the gap between a reactivation-led recovery and the capital required for sustained growth. First, the existing production base declines by roughly 5 percent annually, so a meaningful share of each year's activity replaces lost barrels before creating net gains. Second, conservative new-well productivity requires a much larger drilling program than a simple well-reactivation case would suggest. These factors make new drilling the framework's largest capital category—and the rig ramp its clearest execution test.

¹ Context for current and historical production: Dang, Sheila, and Marianna Parraga, "[Chevron expands Venezuela presence with \\$7 billion plan to double oil output](#)," Reuters (September 2, 2026); US Energy Information Administration (EIA), [Venezuela country analysis brief](#) (February 8, 2024). Current-production range: 1.05 to 1.20 million b/d based on author's review of reporting available through September 8, 2026.

The investment case is therefore staged, not binary. The first \$12 to \$24 billion through 2028 is concentrated on well reactivation, artificial lift, compression, gathering, field power, storage, and exports, together with an initial drilling ramp. Existing surface systems may support 1.5 to 1.6 million b/d at a national level, although reliability and corridor-specific bottlenecks will still constrain individual fields. The practical near-term test is whether the industry can mobilize wells, rigs, and enabling equipment quickly enough.

That sequence creates two different commercial plays. The east is likely to attract larger project commitments and offers the highest-rate wells; Lake Maracaibo carries the deepest recurring intervention workload. Investors and oilfield-service providers should distinguish project exposure from utilization exposure: eastern developments offer larger-ticket upside, while workover, artificial lift, wireline, compression, and on-site power can provide more repeatable demand across operators and financing structures.

Methodology, in Brief

We built the framework from the ground up, beginning with the physical work required to restore and expand production. The starting point is the current active-well base and a probability-weighted pool of realistic reactivation candidates. We then translate that workload into the equipment, crews, and supporting infrastructure required by basin and over time. Finally, we convert the resulting activity profile into capital using global and US unit-cost benchmarks, adjusted by category for the additional logistics, security, procurement, and payment frictions associated with Venezuela.²

The model applies an annual production-weighted decline rate of approximately 5 percent to the existing active-well base before counting gains from reactivation, drilling, or debottlenecking. Some activity in every horizon therefore replaces lost output rather than adding net production. Basin inputs range from 3 to 6 percent in the Orinoco Belt to 5 to 8 percent in Norte de Monagas, with Lake Maracaibo at 4 to 7 percent, Conventional East at 4 to 6 percent, and Other West at 5 to 7 percent. Weighted across the production mix, these assumptions produce a 5.1 percent national rate, rounded to 5 percent in the model and consistent with a separately derived country-level estimate.³

As many inputs remain uncertain, we present ranges rather than point forecasts. Well condition, project scope, productivity, equipment and labor availability, and execution pace can materially affect the result. The framework establishes a planning envelope for the scale, timing, and mix of investment; it does not predict actual spending.

We deliberately limit the scope to the oil-sector operating system. It includes priority well rehabilitation, artificial lift, compression, gathering and pipeline work, storage and export-terminal rehabilitation, gas processing, behind-the-meter power, new drilling, refinery rehabilitation, greenfield surface facilities and upgrading, and a separate offshore-gas track. It excludes debt owed by Petróleos de Venezuela, S.A. (PDVSA) or the sovereign, environmental remediation and decommissioning, nationwide grid reconstruction, broad

² Internal well-inventory analysis: age- and probability-weighted active and reactivation-candidate counts by basin, based on development and non-development well records through 2017 (approximately 55,560 wells drilled historically; approximately 41,857 onshore).

³ Basin-specific decline-rate ranges and the new-well productivity calibration reflect separate field-source reviews. They were developed independently of the BRG working model but have not been externally audited.

road and port renewal, working capital and financing costs, and a full petrochemical rebuild. It should therefore not be read as the total cost of normalizing Venezuela's energy system or economy.⁴

The Well Inventory Defines the Physical Workload

The well inventory points to two distinct types of opportunity, and that distinction matters more than the national well count. In Norte de Monagas and the Orinoco Belt, value is driven primarily by production response: each successful intervention can add materially more barrels. Lake Maracaibo has a different profile. Its large, mature well base offers lower production per well but a much deeper and more repeatable intervention workload.

The commercial consequence is that a single national deployment model would underperform in both regions. The eastern basins reward selectivity: operators should identify the wells and facilities capable of delivering the fastest production response and concentrate capital around them. Lake Maracaibo rewards scale and operating discipline through standardized work scopes, high equipment utilization, dense field coverage, and repeatable execution. For service providers, the distinction points to higher-value selective packages in the east and scaled recurring coverage in Lake Maracaibo.

Table 1. Estimated well inventory and productivity, by major basin

Basin	Estimated active wells	Reactivation candidates	Current wells productivity per well	New wells productivity per well
Orinoco Belt	3,845–4,860	1,145–1,535	75–500 b/d	150–850 b/d
Norte de Monagas	695–1,115	590–870	150–750 b/d	300–1,750 b/d
Conventional East	1,535–2,960	2,090–3,130	50–250 b/d	120–550 b/d
Lake Maracaibo	2,895–6,615	6,580–9,795	25–150 b/d	40–350 b/d
Other West	135–250	150–210	25–175 b/d	50–250 b/d
Offshore	36–46	10–15	4590 MMscf/d (gas)	70–110 MMscf/d (gas)
TOTAL	9,141–15,846	10,565–15,555		

Source: BRG internal well-inventory analysis and scenario assumptions.

Note: Other West includes Barinas/Apure; Offshore consolidates the eastern and western offshore positions. Current-condition productivity shown above differs from the new-well productivity used in next section; the latter is a separate, conservative, field-informed model input.

Note: million standard cubic feet per day (MMscf/d).

Production Recovery Must First Offset Natural Decline

Gross activity and net production are not interchangeable. Reactivated and new wells must first offset decline in the existing base before production can grow. Table 2 shows both a full sensitivity range and a more defensible mid-case. Rig activity and drilling volume are leading indicators; production is the lagging confirmation.

The drilling ramp is the clearest execution test. Working backward from the production targets, the model requires approximately 210 wells per year—roughly 21 concurrent rigs—in the short term (present through 2028), rising to approximately 800 to 850 wells per year and 53 to 55 rigs thereafter. Current rig availability is

⁴ US EIA (2024).

far below those levels, although announced mobilization activity⁵ and the 40- to 80-rig range associated with Venezuela's 1990s drilling cycle⁶ indicate that the modeled scale is operationally plausible. Neither comparison establishes that the required fleet will mobilize on schedule.

Table 2. Assumed Venezuela’s unconstrained oil production build-up

Horizon	Starting point	Net incremental production	Target production at period end
Short term: restore and capture (present–2028)	1.1–1.2 million b/d ⁷	~0.5 million b/d	1.5–1.8 million b/d
Mid-term: optimize and expand (2029–2032)	1.5–1.8 million b/d	~1.0 million b/d	2.5–2.8 million b/d
Long term: scale and diversify (2033–2036+)	2.5–2.8 million b/d	<1.0 million b/d	3.2–3.6 million b/d

Source: BRG bottom-up scenario analysis. The full sensitivity range shown for production figures at the starting point and period end combines the outer ends of basin-level well-count and productivity assumptions simultaneously and should not be treated as a probability-weighted forecast. We set net incremental production in each period based on input from industry experts, analyst opinions, and our own judgment.

The mid-case falls within a reference planning corridor of roughly 1.5 to 1.8 million b/d in the short term (by 2028), 2.5 to 2.8 million b/d in the mid-term (by 2032), and 3.2 to 3.6 million b/d in the long term (beyond 2035). It reaches those levels after applying natural decline and conservative new-well productivity, offset by a substantial drilling program. The evidence threshold rises with each phase: near-term progress can be tested through contract awards, equipment mobilization, well interventions, and rig counts; the mid-term case requires sustained utilization and binding investment decisions; and the long-term case should not be credited until major projects reach financing and execution.

Capital Requirements by Service Sector, Region, and Investment Cycle

The capital envelope becomes more useful when read through three lenses. Service line shows what must be procured; geography shows where well-linked demand concentrates; and timing separates visible near-term work from capital contingent on later projects. The regional view allocates only the categories tied directly to well counts, while the service-line and timing views cover the full \$126 to 180 billion envelope.

Capital by service sector

New drilling is the largest single category at \$46.3 billion, reflecting the wells required to offset decline and reach the production targets. Well intervention and artificial lift remain the largest recurring brownfield category, while greenfield facilities dominate only in the long-term phase.

⁵ Near-term rig context: Baker Hughes data cited by Reuters showed two active onshore drilling rigs at the end of July 2026. SLB said it could reactivate up to fifteen rigs already in the country, including up to four by year-end; Formentera said it was discussing imports; Chevron subsequently said it would more than double its operated rig count. Dang, Sheila, and Marianna Parraga, “[SLB, Formentera working to activate drilling rigs in Venezuela](#),” Reuters (August 19, 2026); Dang, Sheila, “[Chevron to double oil rigs in Venezuela as part of growth plan](#),” Reuters (September 8, 2026).

⁶ Historical Venezuela drilling-activity benchmark for the 1990s—approximately 750 to 800 wells per year and 40 to 80 active rigs—is based on available information published by PDVSA, S&P Global, Wood Mackenzie, and Baker Hughes.

⁷ Based on the latest [OPEC Monthly Oil Market Report](#) from September 10, 2026: Venezuela crude oil production for 2026 YTD ranges from 1,013 million bpd in Q1 2026 to 1,201 million bpd in August 2026.

Table 3. Capital spending allocation by major service category

Category	Range (\$billion)	Mid-case (\$billion)	Interpretation
New drilling	\$43.8–48.9	\$46.3	Largest capital category; driven by decline-adjusted well requirements
Well intervention and artificial lift	\$16.3–17.9	~\$17.1	Largest recurring brownfield category
Greenfield surface facilities and upgrading	\$25.0–39.0	~\$32.0	Almost entirely long term
Gathering and pipeline rehabilitation	\$8.0–18.0	~\$13.0	Short to mid-term weighted
Refining rehabilitation	\$9.0–14.0	~\$11.5	Mid- to long term
Offshore gas (separate track)	\$8.0–15.0	~\$11.5	Separate gas track; includes illustrative offshore drilling
On-site power generation	\$4.5–7.4	~\$6.0	Modular and sponsor-agnostic; short to mid-term
Storage and export terminals	\$3.0–6.0	~\$4.5	Mid-term weighted
Compression (restore + new)	\$2.0–5.0	~\$3.5	Lower-cost, modular restoration lever
Gas processing and flaring reduction	\$2.0–5.0	~\$3.5	Mid-term weighted
Wireline	\$1.9–2.0	~\$1.9	Recurring demand grows with active-well base
TOTAL	\$126–180	~\$151	

Source: BRG bottom-up scenario analysis; well-count-driven categories were computed from basin-level data. New drilling is a point estimate because the activity schedule is a single assumption calibrated to the production target. Displayed category ranges sum to approximately \$126 to \$176 billion; the headline upper bound is rounded to \$180 billion to avoid false precision. Mid-case values sum to approximately \$151 billion.

Offshore gas. Offshore gas development involves real drilling commitments, not just infrastructure spend. Shell's Dragon field, the BP-led Loran and Cocuina-Manakin developments, Eni/Repsol's Cardón IV expansion, and BP's early stage evaluation of Mariscal Sucre all involve actual drilling commitments, not just infrastructure spend.⁸ This framework carries an illustrative schedule of roughly thirty-nine offshore wells (four short-term, twenty mid-term, fifteen long-term) across the full period, split by cluster: Dragon, Loran, Cocuina-Manakin, and Mariscal Sucre in the east; Cardón IV, the more established and currently expanding position, in the west. At an offshore cost premium of five to ten times the cost of onshore drilling (offshore

⁸ Reuters and company disclosures on offshore gas developments, 2025–2026: Shell's Dragon and Loran Phase 1 positions; BP's Loran Phase 2 and Cocuina-Manakin developments; Eni/Repsol's Cardón IV expansion; and BP's memorandum covering Mariscal Sucre/Carúpano East. The thirty-nine well schedule and basin split are the author's illustrative estimates, not disclosed field plans.

wells run materially higher than onshore across water depth, subsea equipment, and logistics), this implies \$1.2 to \$2.3 billion of drilling capital—a small enough share of the existing \$8 to \$15 billion offshore-gas envelope that it fits comfortably within it rather than requiring the total to move. The remaining \$6 to \$13 billion covers subsea infrastructure, tiebacks, and processing, which is the more typical cost weighting for offshore gas developments. This schedule is illustrative, not a disclosed field-by-field plan, and should be read as an order-of-magnitude placeholder rather than a committed forecast.

Capital by region

Splitting regional spending by what it actually buys—restoring wells already in the ground versus drilling new ones—tells a sharper story than a single blended figure per basin. The two categories behave differently: existing-well spending (workover, wireline, and the active-well share of compression) tracks the size of each basin's current well stock, while new-well spending follows the drilling schedule laid out in the previous section, concentrated early in Orinoco Belt and Norte de Monagas and broadening over time.

Two findings stand out. First, new-well drilling outweighs existing-well spending throughout the eastern basin—this is fundamentally a drilling story, even at the regional level. Norte de Monagas makes the point most sharply: it holds one of the smallest legacy well bases in the table, yet ranks second in total capital purely on the strength of its drilling priority. Second, Lake Maracaibo is the one basin where the relationship inverts—its existing-well spending alone is more than double any other basin's, a direct reflection of carrying over half the country's addressable well count, while its new-drilling allocation stays comparatively modest. Orinoco Belt and Lake Maracaibo end up similarly sized in total capital, but for opposite reasons: one is a drilling story, the other a fleet-size story.

Table 4. Capital spending allocation by major basin/region

Basin	Existing-/active-well spending (\$billion)	New-drilling spending (\$billion)	Well-related basin total (\$billion)	Other capital activity
Orinoco Belt	\$5.0–5.1	\$20.0–22.0	\$25.0–27.1	Largest recipient of current capital and modeled drilling—Chevron, Eni, and most NABEP fields
Norte de Monagas	\$1.3–1.6	\$8.0–9.8	\$9.3–11.4	Hunt Oil/Crossover's Caro and Carisito fields; second-largest modeled drilling allocation
Conventional East	\$3.7–4.8	\$7.6–8.4	\$11.3–13.2	Legacy fields, selected private-operator activity, and rising drilling share in the mid- and long term
Lake Maracaibo	\$9.7–13.0	\$6.0–7.5	\$15.7–20.5	Limited current deal flow relative to well count; the country's largest recurring-service opportunity remains largely uncommitted
Other West	\$0.2–0.4	\$1.5–2.0	\$1.7–2.4	Limited infrastructure and low current priority
Total	\$19.9–24.9	\$43.1–49.7	\$63.0–74.6	

Source: BRG bottom-up scenario analysis. New-well spending is shown as ranges to prevent false precision. Figures exclude the separate offshore-gas track (see “Capital by service sector” above), which carries its own illustrative drilling estimate and is not basin-allocated here.

From these well-specific estimates to the total. The \$63.0 to \$74.6 billion shown above is the well-count-driven and drilling capital that can be traced to a specific basin. It is a little less than half of the \$118 to \$165 billion core oil system. The remainder—roughly \$53 to \$90 billion—sits in greenfield facilities, gathering and pipeline rehabilitation, refining, storage and export terminals, gas processing, and on-site power. These categories are capital-intensive but not basin-allocated, as they concentrate wherever specific projects are sanctioned rather than scaling with well count the way workover and drilling do; the next section addresses where that activity is currently concentrated in qualitative terms. Adding the separate \$8 to \$15 billion offshore-gas track on top of the \$118 to \$165 billion core range completes the \$126 to \$180 billion total.

Capital by investment cycle

Capital rises sharply through the mid-term as drilling approaches its modeled steady-state rate, then remains high in the long term as greenfield facilities scale. The \$12 to \$24 billion short-term phase is the most visible portion of the opportunity; most of the remaining capital depends on sustained execution and later project commitments.

Table 5. Capital spending allocation by time period

Horizon	Capital range (\$billion)	Mid-case (\$billion)	What dominates
Short term (2026–2028)	\$12–24	~\$15	New drilling and well intervention; brownfield restoration plus a rig ramp
Mid-term (2029–2032)	\$47–66	~\$56	New drilling; gathering, storage, and refinery rehabilitation continue
Long term (2033–2036+)	\$67–91	~\$79	Greenfield facilities and continued drilling both scale
TOTAL	\$126–180	~\$151	

Source: BRG bottom-up scenario analysis. Totals include the separate offshore-gas track. Values are rounded from the underlying model and may not sum exactly; the regional table quantifies only well-count-driven and drilling categories.

The practical sequence: restore production equipment and flow assurance first; run the drilling program at the calibrated pace rather than either understating it (which misses the production target) or assuming it can be deferred (which natural decline does not allow); add greenfield and refining commitments as infrastructure capacity and contract durability improve.

Capital and Workload Point to Different Regions

Capital concentration and service utilization do not map to the same regions. The east—particularly the Orinoco Belt and Norte de Monagas—is positioned to attract larger commitments, higher production per successful intervention, and most of the modeled drilling program. Lake Maracaibo follows a different commercial logic: its mature asset base creates the country's largest concentration of recurring well-intervention and artificial-lift demand.⁹

⁹ Company and government announcements from April to September 2026, including Reuters reporting on Eni/Junín-5 (April 28), Repsol/Petroquiriquire in Lake Maracaibo (June 16), Maurel & Prom's Venezuelan operations and resumed exports (August 6), Hunt

That distinction calls for two go-to-market models. Capturing the east will be relationship- and project-led, often through larger integrated packages. Lake Maracaibo is more utilization-led: success depends on dense field coverage, local inventory and workshops, standardized work scopes, and repeat contracts across multiple operators. A platform spanning both regions could combine eastern project upside with a steadier western utilization base.

Table 6. Regional summary of opportunities, positioning and commercial implications

Region	Physical opportunity	Current positioning	Commercial implication
Orinoco Belt	Heavy-oil development, facilities, and largest modeled drilling allocation	Chevron, Eni, NABEP, and legacy joint ventures	Prioritize integrated, larger-contract relationships
Norte de Monagas	Highest per-well productivity; second-largest drilling recipient; strong gas-lift and compression demand	Hunt Oil/Crossover and established mature-field operations	Prioritize high-value interventions and gas handling
Conventional East	Brownfield rehabilitation, compression, and rising drilling share in the mid- and long term	Legacy fields plus renewed private-operator activity	Target fast-payback restoration packages
Lake Maracaibo	Largest intervention and artificial-lift workload; extensive mature infrastructure	Existing Chevron, Repsol, and Maurel & Prom positions; less disclosed incremental capital than the east	Build around recurring service coverage and local execution
Other West	Smaller, fragmented opportunity with infrastructure and logistics constraints	Limited current capital commitments	Selective entry through local partners
Offshore	Gas development, subsea infrastructure, tiebacks, and processing	Shell, BP, and Eni/Repsol; eastern commercialization links to Trinidad and Cardón IV anchors the West	Target integrated gas, subsea, and cross-border project packages

Source: Company disclosures; Reuters; BRG research and analysis.

Service Demand Persists After Reactivation Wave

Venezuela's service opportunity should extend well beyond the initial reactivation campaign. Restoring shut-in wells creates the first wave of activity, but natural decline, new drilling, and an expanding active-well base generate recurring demand thereafter. The shape of that demand differs by service line: drilling provides the largest growth opportunity; workover, artificial lift, and wireline follow the installed well base; and compression and on-site power enable production across fields and operators.¹⁰

Oil/Crossover Energy (Caro and Carisito, August), Chevron's expanded Petroindependencia position (September 2), and White House/NABEP announcements (August 31–September 1).

¹⁰ Productivity assumptions (cycle times, job-type mix, and run-life by lift type) reflect direct field experience in Venezuela's eastern producing basins and selected industry conversations.

For service providers, the central question revolves around which activities represent a temporary backlog, which develop into a recurring operating requirement, and where equipment and local capacity should be positioned before demand accelerates.

Drilling rigs and the scale of the required ramp

Meeting the modeled production trajectory requires approximately 210 new wells per year through 2028, rising to roughly 800 to 850 annually thereafter. Based on assumed productivity of 8 to 12 wells per rig per year initially, improving as equipment and crews gain operating experience, the program would require approximately 21 concurrent drilling rigs in the short term and 53 to 55 in the mid- and long terms.

Table 7. Drilling rig demand, by time period

Drilling demand	Short term	Mid-term	Long term
Estimated new wells per year	200–220	800–850	800–850
Wells/rig/year	8–12	12–16	14–16
Concurrent drilling rigs (mid-case; range)	~21 (18–24)	~55 (52–58)	~53 (50–56)

The near-term requirement is substantial relative to the two onshore drilling rigs reported active at the end of July 2026. Announced mobilization plans nevertheless indicate that capacity is beginning to return: SLB has identified as many as 15 stored rigs that could be reactivated, Formentera has discussed importing additional units, and Chevron plans to more than double its operated rig count.¹¹ These announcements may overlap and do not yet constitute a commitment to the full fleet required by the model. The 53 to 55 rigs required thereafter fall within the broad 40- to 80-rig range associated with Venezuela’s 1990s drilling cycle, supporting the operational plausibility of the requirement but not its timing.¹²

The geographic mix also changes over time. The Orinoco Belt and Norte de Monagas account for approximately 80 percent of short-term drilling demand, reflecting their higher expected new-well productivity. Their combined share falls to around two-thirds in the later periods as activity expands into Conventional East and Lake Maracaibo. The early market is concentrated around a limited number of eastern operators and developments; the later opportunity depends on a broader group of fields and sponsors sustaining the drilling program.

Workover rigs: two demand streams in one fleet

Workover demand combines a declining backlog with a growing recurring requirement. Reactivating shut-in wells drives the initial surge but diminishes as the candidate inventory is addressed. Simultaneously, the number of producing wells requiring scheduled pump and rod replacement rises throughout the period. These two demand streams use much of the same equipment but move in opposite directions.

¹¹ See note 5 for the near-term rig-activity and mobilization sources.

¹² See note 6 for the historical drilling-activity benchmark and its limitations.

Table 8. Workover rig demand, by time period

Workover demand	Short term	Mid-term	Long term
Backlog workover rigs (mid-case; range)	~46 (40–50)	~14 (12–16)	~4 (3–5)
Sustained workover rigs (mid-case; range)	~50 (45–55)	~73 (70–75)	~93 (90–95)
Total concurrent fleet (mid-case; range)	~96 (85–105)	~86 (82–90)	~97 (96–98)

The result is a relatively durable fleet requirement rather than a short-lived reactivation cycle. Total demand declines from ~96 rigs in the short term to ~86 in the mid-term, before returning to ~97 by the long term as sustaining activity replaces the initial backlog. Providers that treat reactivation as a temporary mobilization may therefore underestimate the operating capacity required after the first phase.

Lake Maracaibo accounts for approximately half of the modeled workover fleet at each horizon. That demand reflects the scale and maturity of its well base rather than the plans of any single operator, reinforcing the basin’s value as a multi-operator service-platform opportunity.

Wireline units: a smaller market with steadier growth

Wireline demand is driven primarily by recurring gas-lift valve servicing, supplemented by minor well interventions and work associated with completions and workovers. Unlike the workover fleet, it does not experience a mid-term decline: both the gas-lifted well population and drilling-linked activity increase over time.

Table 9. Wireline services demand, by time period

Wireline demand	Short term	Mid-term	Long term
Gas-lift driven demand (mid-case; range)	~19 (18–20)	~28 (25–30)	~36 (34–40)
Other well servicing demand* (mid-case; range)	~17 (15–18)	~24 (22–26)	~24 (22–26)
Total concurrent wireline units (mid-case; range)	~36 (33–38)	~52 (47–56)	~60 (58–66)

* Other well servicing demand includes minor well intervention jobs, as well as rig- and drilling-linked demand

The modeled fleet grows from approximately 36 concurrent units in the short term to around 60 in the long term—an increase of roughly two-thirds. Demand is smaller than the workover requirement but follows a more consistent growth path, with particular concentration in Norte de Monagas and parts of Lake Maracaibo. That combination favors locally positioned equipment and standing regional service agreements over repeated job-by-job mobilization.

Artificial lift: the mechanism behind two different service lines

Artificial lift links the well inventory to recurring service demand. Only an estimated 5 percent of Venezuela’s active wells can flow naturally. The remainder is divided among progressing cavity pumps (PCPs) at approximately 17.5 percent of the well base; electric submersible pumps (ESPs) at 12.5 percent; rod lift at

32.5 percent; and gas lift at 32.5 percent. PCPs are concentrated in the extra-heavy crude of the Orinoco Belt, while gas lift is particularly important in Norte de Monagas and parts of Lake Maracaibo.

The service requirement differs materially by lift type. PCP systems typically operate for approximately thirty to thirty-six months before replacement, rod-lift systems for around twenty-four months, and ESPs for approximately eighteen to twenty-four months under heavy-oil conditions. Servicing these systems generally requires a workover rig. Gas-lift valves operate on a shorter cycle—approximately twelve months—but can normally be serviced using wireline. The lift mix therefore creates two related but distinct recurring markets: rig-based mechanical replacement and higher-frequency wireline intervention.

Compression: a lower-capital enabling lever

Compression represents only \$2.0 to \$5.0 billion of the capital framework but enables larger sources of production and service demand. BRG estimates that approximately 900 to 1,000 compressor units are installed across the country, of which perhaps 20 to 30 percent are currently operating. Many idle units appear to be constrained by gas availability, power, or deferred maintenance rather than irreparable equipment failure, making part of the opportunity a repair-and-restart program rather than a full replacement cycle.¹³

Restored and new compression supports gas-lift injection, reservoir-pressure maintenance and enhanced oil recovery, gathering systems, and flaring reduction. Compression can also return mechanically sound but pressure-constrained wells to production without the capital or lead time associated with drilling a new well. At the Venezuela-adjusted unit costs used in the model, the capital range represents approximately 0.6 to 1.4 million horsepower of restored and new capacity. This creates an early opportunity for diagnostics, refurbishment, field maintenance, and integrated compression-and-power packages.

On-site power: two markets within one buildout

Reliable field power is a prerequisite for artificial lift, compression, gathering pumps, and production instrumentation. The modeled program includes approximately 2,100 to 3,200 installations totaling 2.3 to 3.8 gigawatts, but the number of installations and the required capacity are distributed very differently.

Individual well pads requiring approximately 100 kilowatts to 1 megawatt (MW) account for roughly 1,800 to 2,600 installations. Multi-well pads and small gathering stations requiring 1 to 5 MW add another 250 to 450 installations. At the other end of the market, approximately 75 to 125 gathering and compression nodes and area hubs require systems ranging from 5 MW to more than 45 MW. These larger installations are fewer in number but represent a disproportionate share of total capacity.

This results in two complementary commercial opportunities: a high-volume market for modular and rental-friendly generation at well pads and gathering sites, and a smaller market for larger, integrated power projects at compression nodes and regional hubs. Both are distinct from the GE Vernova/CORPOELEC national-grid initiative, which focuses on central generation and transmission. The capacity modeled here is behind the meter and oilfield-specific, making its deployment less dependent on the timing of the broader grid recovery.¹⁴

¹³ BRG facility-count and load-profile model; BRG, “Venezuela Revised Outlook,” August 2026.

¹⁴ Grid context: Gardner, Timothy, “[U.S. says deal aims to stabilize Venezuela power grid in 6–12 months](#),” Reuters (September 3, 2026).

Other infrastructure: project-specific rather than well-count-driven

The remaining capital categories are less suited to unit-by-unit modeling because demand is determined by specific fields, corridors, and facilities rather than the national well count. They remain essential to converting wellhead production into saleable barrels.

Gathering and pipeline rehabilitation addresses integrity and evacuation constraints between producing fields and processing facilities. Storage, blending, and export-terminal capacity could become a near-term bottleneck if production recovers faster than crude-handling capacity. Gas processing and flaring reduction can redirect associated gas toward compression, power generation, reinjection, or sale. Refinery rehabilitation supports domestic product supply and the recovery of higher-value conversion capacity.

Greenfield surface facilities and upgrading represent the largest long-term surface-infrastructure category. These investments become necessary as drilling moves beyond assets that can rely on existing facilities and begins to require new processing, upgrading, and crude-handling capacity. Unlike recurring well services, however, this spending should be credited only as individual developments reach commercial sanction, financing, and execution.

Is the \$100 Billion Headline Plausible?

Yes—as an order-of-magnitude signal, not a national budget. BRG's bottom-up framework estimates \$118 to \$165 billion for the core oil system and \$126 to \$180 billion including the separate offshore-gas track, with a combined mid-case of approximately \$151 billion. NABEP's announced \$100 billion sits below the central estimate once natural decline and conservative new-well productivity are incorporated into the drilling requirement.

The NABEP–US government announcement covers a specific portfolio of seventeen-fields containing approximately 65 billion barrels of reported reserves, rather than a complete national-sector rebuild.¹⁵ It is best read as the long-term financing and development ambition for that portfolio. It is neither a disclosed bottom-up capital plan nor independent validation of the BRG range because the two scopes overlap substantially.

Published third-party assessments span approximately \$10 to \$20 billion for targeted brownfield gains to roughly \$183 billion for a broader return to 3 million b/d.¹⁶ Rystad's \$183 billion estimate is close to BRG's \$180 billion high end, but the convergence should not be over-read because the estimates use different scopes, timelines, and methods.

The implication. The \$100 billion headline is plausible as a long-term portfolio ambition and a lower-bound reference for national scale. It should not be treated as near-term spending, a national ceiling, or independent

¹⁵ Binkley, Collin, Juan Pablo Arráez, and Regina Garcia Cano, “[What we know about Trump's deal giving U.S. access to vast oil reserves in Venezuela](#),” Associated Press (August 31, 2026); Stone, Mike, “[U.S. structured Venezuela oil position to protect it from dilution](#),” Reuters (September 4, 2026); Singer, Florantonia, and Alonso Moleiro, “[El pacto petrolero entre Estados Unidos y Venezuela](#),” El País (September 8, 2026).

¹⁶ Crooks, Ed, “[What could change in Venezuela mean for oil production?](#),” Wood Mackenzie (December 5, 2025); Setser, Brad W., “[Increasing Venezuela's Oil Output Will Take Several Years—and Billions of Dollars](#),” Council on Foreign Relations (January 8, 2026); Rystad Energy, “[What would it take to bring Venezuela's oil output back to 3 million bpd?](#),” AJOT (January 6, 2026).

validation of the BRG estimate. The \$12 to \$24 billion short-term program remains the most visible and executable portion of the opportunity.

Positioning: Who Can Capture the Opportunity

The opportunity will not accrue simply to the companies with the largest acreage or headline commitments. The strongest positions combine operating authority, existing infrastructure, technical capacity, equipment, market access, and contracts robust enough to convert capital into production and cash flow. Conversion capacity—not announced scale—is the more useful basis for comparing participants.

PDVSA remains indispensable to that process. It retains interests across much of the producing asset base and continues to influence shared infrastructure, operating coordination, crude handling, and exports. But its limited capital availability, accumulated maintenance requirements, and payment history constrain its ability to lead the recovery independently. Progress will depend on partner capital, clear operating governance, and executable payment arrangements.

Table 10. Relative competitive positioning – E&P operations

Company/type	Position	Basis
PDVSA	Essential system counterparty; constrained standalone investor	Interests across much of the producing base and influence over shared infrastructure; recovery increasingly depends on partner capital, execution capacity, and workable governance and payment arrangements
Chevron	Strongest near-term scale and execution position	Existing infrastructure and operating history; more than \$7 billion five-year plan; expanding acreage and rig activity across established joint ventures
Eni/Repsol	Established, diversified platforms	Eni combines Junín-5 with offshore gas; Repsol combines Lake Maracaibo oil with Cardón IV gas and has regained operating control
GeoPark/Grupo Gilinski	Emerging, operator-led Orinoco Belt redevelopment platform	Twenty-five year production participation contract (CPP) for the producing Bare Block; GeoPark will operate with a 65% net working interest and fund 100% of approved capital using an existing ~1,100-well and infrastructure base to pursue phased brownfield redevelopment
NABEP	Largest headline optionality; highest execution uncertainty	Seventeen-field platform and US alignment, offset by financing, governance, term, and contract-durability questions
Shell / BP	Strategic gas and selected onshore potential	Offshore commercialization through Trinidad can reduce dependence on Venezuela's domestic midstream, but cross-border execution remains complex
Hunt Oil/Crossover	Emerging, Norte de Monagas-focused position	Caro and Carisito provide early exposure to a high-productivity basin and major drilling priority
Maurel & Prom	Focused western brownfield position	Urdaneta Oeste gives direct exposure to Lake Maracaibo's recurring intervention opportunity

Oilfield-services majors and local specialists	Broad near-term revenue opportunity	Pre-positioned equipment and recurring demand reduce dependence on any one field owner; larger drilling requirement expands opportunity
Chinese/Russian legacy positions	Transition and dispute risk	Some fields have shifted to newly backed operators; legal claims and commercial renegotiation may matter more than near-term growth

Sources: Company disclosures; Reuters; BRG research and analysis.

Chevron is the clearest disclosed benchmark. Its joint ventures plan to invest more than \$7 billion over five years to approach 600,000 b/d, and the company plans to more than double its operated rig count.¹⁷ The announcement supports the direction of the near-term drilling ramp but does not disclose enough detail to validate the exact twenty-one rig requirement. More broadly, the near-term advantage lies with incumbents and equipment-backed platforms. New entrants should be assessed against operating control, funding certainty, payment protection, and mobilization—not acreage alone—to pursue phased brownfield redevelopment, although the production ramp and contractual protections remain to be demonstrated in execution.

Implications for Investors, Operators, and Service Providers

Taken together, the analysis describes a sequence of markets with different timing, risk, and commercial requirements. Near-term underwriting should focus on the ability to mobilize equipment, execute interventions, and sustain field operations; the later phases depend increasingly on durable financing, governance, and project commitments. Six practical implications follow:

1. **Underwrite the drilling ramp explicitly.** At \$46.3 billion, new drilling is the largest capital category and main bridge between reactivation-led recovery and production above 3 million b/d. Returns depend on whether operators can contract and sustain roughly twenty-one rigs in the short term and more than fifty thereafter.
2. **Do not treat \$100 billion as the national ceiling.** NABEP's announcement falls below the framework's central estimate, with most of the difference concentrated in the drilling required to offset decline and add net production.
3. **Do not assume a uniform infrastructure bottleneck.** National surface capacity may support the first leg of recovery, but field-level power, flow assurance, and evacuation constraints still determine whether additional wells produce saleable barrels. Well programs and enabling infrastructure should be planned by field and corridor.
4. **Build around recurring, sponsor-agnostic demand.** Workover, artificial lift, wireline, compression, and on-site power provide exposure across operators while the larger drilling requirement broadens the addressable rig and drilling-services market.

¹⁷ NBC News, “[U.S. oil giant Chevron confirms it will expand operations in Venezuela](#)” (September 2, 2026); Dang, Sheila, and Marianna Parraga, “[Chevron expands Venezuela presence with \\$7 billion plan to double oil output](#),” Reuters (September 2, 2026); Dang, Sheila, “[Chevron to double oil rigs in Venezuela as part of growth plan](#),” Reuters (September 8, 2026).

5. **Treat Lake Maracaibo as a service-platform opportunity.** The model assigns approximately \$11.6 billion of existing well-driven demand (e.g., wireline, workover, well reconditioning) to the basin despite comparatively limited new capital commitments.
6. **Track leading indicators.** Rig activations, contract awards, drilling completions, and field-level production response will show whether announced capital is becoming executable.

Evidence, Confidence, and Sourcing

This analysis distinguishes among observed and publicly disclosed information, BRG model outputs, and judgment-based inputs. Public production data, company announcements, contract activity, and reported rig mobilization provide the strongest basis for describing current conditions. Market developments and company announcements are current through September 8, 2026.

The well inventory, regional productivity assumptions, job mix, intervention cycle times, artificial-lift run life, and service-demand estimates are derived from BRG working analysis, direct field experience, and selected industry discussions. Two targeted field-source reviews informed the calibration: one addressed new-well productivity and the other basin-specific decline rates. These inputs strengthen the analysis but remain judgment-based and have not been independently audited. Capital estimates use external benchmarks where available, adjusted for Venezuela-specific logistics, security, procurement, and payment conditions. Confidence is highest in the direction and sequencing of demand, moderate in the basin-level equipment requirements and capital ranges, and lowest in the timing and financeability of long-term projects.

Several headline figures—including NABEP's announced investment, reported reserve volumes, and future company spending commitments—originate with transaction parties, government statements, or public reporting. They are presented as reported rather than independently confirmed. The framework is intended to assess scale, sequencing, and potential commercial exposure; it is not a substitute for project-level diligence. Rig activations, contract awards, drilling completions, and field-level performance should therefore be used to refresh the case as execution progresses.

About the Author

FRANCO CIULLA is a managing director in BRG's Energy & Climate practice. He has over thirty years of experience across the energy industry and more than two decades in strategic advisory. He advises companies and investors on growth, transactions, market strategy, and complex investment decisions across upstream oil and gas, oilfield services, power, and energy infrastructure, with particular experience in Venezuela and Latin America.

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