CENTER FOR GLOBAL DEVELOPMENT

Nigeria's Super-Emitter Flares

An Updated Evaluation of Trends and Causes of Natural Gas Wastage

ETIENNE ROMSOM · KATHRYN McPHAIL

Abstract

The wasteful flaring and venting of gas associated with oil and gas production and processing is a persistent problem, leading to lost taxable income and reduced energy efficiency and access, adverse health impact, and global warming. This paper updates a 2023 report on the gas flaring behaviors of five Nigerian super-emitter offshore flares operated by international oil companies that had revealed very high flaring levels over the period 2012–2022. Updated satellite data up to June 2026 show a mixed picture of recent performance, with some improvement but also evidence of continued excess flaring behavior; three of the five are still classified as active global super-emitters. The paper explores the reasons for continued flaring behaviors, including the inadequate determination of "routine flaring" that allows continuous flaring to sustain operations. It develops a practical way to measure routine flaring when defined as all flaring except for safety purposes. The paper analyses the interrelationships between gas flaring and oil production processes and demonstrates, with quantitative analysis for each flaring location, that existing incentives have not fostered good quality field operations to minimize flaring and optimize oil reserves. In periods of prolonged high flare intensity, oil production declines faster, potentially compromising ultimate oil recovery. Together, the five flaring sites are estimated to have incurred over USD4 billion of lost potential gas export sales due to flaring. The range of observed outcomes shows that with a stable climate for infrastructure investments, including gas monetization projects, and good operational policies, it is possible to significantly reduce gas flaring.

POLICY PAPER 413 • NOVEMBER 2026

Nigeria's Super-Emitter Flares: An Updated Evaluation of Trends and Causes of Natural Gas Wastage

Etienne Romsom and Kathryn McPhail
EnergyCC

To assess the emissions performance of these Nigeria assets, data provided by VIIRS Nightfire (VNF) satellites were used as a diagnostic tool to measure and assess flares (Elvidge, Christopher D., Mikhail Zhizhin, Feng-Chi Hsu, and Kimberly E. Baugh. "VIIRS nightfire: Satellite pyrometry at night." Remote Sensing 5, no. 9 (2013): 4423–4449). This work has been made possible with the welcome support from the Earth Observation Group, Payne Institute for Public Policy.

The authors appreciate comments from Mark Plant, Senior Fellow Emeritus, and John Hicklin, Non-Resident Fellow, CGD; Sir Mark Moody-Stuart, Chairman and Mark Cutifani, Senior Adviser, EnergyCC; the Government of Nigeria (Federal Ministry of Finance); Axel Schimmelpfennig, Assistant Director and Mission Chief for Nigeria, and Ian Parry, Fiscal Affairs Department, IMF; Chevron, ENI, Exxon, Shell, and TotalEnergies; CGD internal and anonymous external peer review; all of which have improved the paper. Special thanks to Kenneth Ene, Pacepoint Advisory and Professor Alan Roe, Honorary Professorial Fellow in Economics, University of Warwick, for their advice, guidance, and interest in the project.

EnergyCC works collaboratively with public, private, and civil society organizations on the energy transition. In 2019, EnergyCC developed a methodology to reduce methane emissions from the energy sector (https://doi.org/10.35188/UNU-WIDER/2021/940-2).

Etienne Romsom and Kathryn McPhail. 2026. "Nigeria's Super-Emitter Flares: An Updated Evaluation of Trends and Causes of Natural Gas Wastage." CGD Policy Paper 413. Washington, DC: Center for Global Development. https://www.cgdev.org/publication/nigerias-super-emitter-flares-updated-evaluation-trends-and-causes- natural-gas-wastage

CENTER FOR GLOBAL DEVELOPMENT
2055 L Street, NW Fifth Floor
Washington, DC 20036

1 Abbey Gardens
Great College Street
London
SW1P 3SE

www.cgdev.org

Center for Global Development. 2026.

The Center for Global Development works to reduce global poverty and improve lives through innovative economic research that drives better policy and practice by the world's top decision makers. Use and dissemination of this Policy Paper is encouraged; however, reproduced copies may not be used for commercial purposes. Further usage is permitted under the terms of the Creative Commons Attribution-NonCommercial 4.0 International License.

The views expressed in CGD Policy Papers are those of the authors and should not be attributed to the board of directors, funders of the Center for Global Development, or the authors' respective organizations.

Contents

Foreword 1

Summary 2

Reviews and feedback 5

1. Introduction to the super-emitter performance study 6

2. Nigeria flaring performance history 10

3. Super-emitter operations performance overview 13

4. Super-emitter flaring energy and value loss assessment 16

5. Gas flaring intensity and variability measures 22

6. Assessment of routine flaring in super-emitter operations 23

7. Oil decline and flaring intensity 29

8. Flaring performance review by asset 35

- 8.1 Agbami 37
- 8.2 Yoho 42
- 8.3 Usan 47
- 8.4 Abo 54
- 8.5 Bonga 61

9. Conclusions 68

Appendix A. Comparison of VNF satellite flare rates with reported flare rates 70

Appendix B. Glossary and acronyms 75

Figures

1. Oil production and flare rates for the largest contributing countries 2005–2024 10
2. Nigeria's largest 100 flares by location in the period 2017–2024 12
3. Nigeria's largest flare rates in the period 2017–2024 12
4. (a) Oil production and (b) flare rates for the five offshore assets 13
5. Oil production and flare trends for the offshore assets (a top, b bottom) 14
6. Gas flare energy and value loss trends for each of the five offshore assets 18
7. Gas flare energy and value loss trends for the five offshore assets combined 18
8. Seasonal flare rate variations for Usan (2012–2025) 19
9. Gas flaring linked to oil production life cycle 20
10. Gas flare energy and value loss trends for Bonga 21
11. Flare intensity for the five offshore assets and combined trend (2012–June 2026) 22
12. Flare variability for the five offshore assets and combined trend (2012–June 2026) 23
13. Schematic of method for determining routine flaring versus non-routine flaring 26
14. Routine flaring assessment method applied to Bonga 27
15. Routine flaring contribution to total flaring 28
16. Cross plot of routine flaring percentage versus total flare rate (by month) 29
17. Agbami asset oil decline and flare intensity (annual averages) 31
18. Agbami asset oil decline and flare intensity (3-month trailing moving averages) 31
19. Agbami asset (3-month TMA) oil decline and (12-month TMA) flare intensity 32
20. Bonga asset oil decline and flare intensity (3-month TMA) 32
21. Bonga (top) and Usan (bottom) asset oil decline and flare intensity (3-month TMA) 33
22. Oil decline rate versus flare intensity by year for the portfolio of five offshore assets 34
23. Agbami flare performance overview 38
24. Agbami asset oil decline and flare intensity (3-month TMA) 39
25. Agbami asset oil production, decline and flare rate 40

26. Agbami poor flare quality observations 41
27. Yoho flare performance overview 43
28. Individual flare measurements of Yoho in 2025 44
29. Yoho asset flare intensity and percentage of solution gas flared 45
30. Yoho poor flare quality observations 45
31. Overview of UTM FLNG venture with commercial, financial and product interfaces 46
32. Usan flare performance overview 48
33. Usan flare observations and non-routine flare assessment 50
34. Usan routine flaring assessment and trends 51
35. Usan asset oil production, decline and flare rate 52
36. Usan poor flare quality observations 53
37. Abo flare performance overview 55
38. Abo asset flare intensity and percentage of solution gas flared 56
39. Abo calculated produced gas oil ratio 56
40. Gas flare energy and value loss trends for Abo asset 57
41. Abo asset oil production, decline and flare rate 58
42. Daily flare observations for Abo in 2023 59
43. Oil production with field and activity decline curves for Abo 61
44. Bonga flare performance overview 62
45. Bonga field activities affecting oil production and gas flaring rates 64
46. Bonga flare observations 65
47. Bonga asset oil production, decline and flare rate 66
48. Bonga poor flare quality observations 67
A1. Comparison of VNF satellite data with reported flare data by month June-2022 to February 2026 70
A2. Comparison of VNF satellite data with reported flare data for the four assets combined, by month June-2022 to February 2026 71

A3. Comparison of VNF satellite data with reported flare data for the four assets combined, based on average daily flare rates per calendar year in the period June-2022 to December 2025 72

A4. Comparison of VNF satellite data with reported flaring for the individual assets, based on average daily flare rates per calendar year from June 2022 to December 2025 73

A5. Comparison of Abo individual VNF satellite data with monthly reported and monthly VNF average flare data for 2024 and 2025 74

A6. Reported breakdown of Abo produced gas and GOR based on monthly reports 74

Tables

1. Energy losses from gas flaring as percentage of the energy value of crude produced 17

2. Value losses (in USD mln) from gas flaring at LNG export price of USD 10/MMBtu 17

3. Agbami oil production and gas flaring performance (2020–2026 year-to-date) 39

4. Yoho oil production and gas flaring performance (2020–2026 year-to-date) 44

5. Usan oil production and gas flaring performance (2020–2026 year-to-date) 49

6. Abo oil production and gas flaring performance (2020–2026 year-to-date) 60

7. Bonga oil production and gas flaring performance (2020–2026 year-to-date) 65

Foreword

Gas flaring and venting—the burning or release of natural gas associated with oil and gas production and processing—wastes some 8 percent of global gas production, a loss worth over USD100 billion annually. This practice is responsible for roughly one-quarter of methane emissions from human activity that contribute to global warming, and the health consequences of poor-quality flaring are severe. Nonetheless, the extent of the waste and the harmful effects are largely invisible in global policy discussions. The case of Nigeria is especially notable. The country ranks eighth in the world for gas flaring. In 2024, the value of this wasted flare gas was around USD1.6 billion. Earlier progress in reducing flaring from extremely high levels stalled in the past decade and existing regulatory policies are proving insufficient to stem emissions. Understanding the reasons why, and highlighting the needed policy response, is important for Nigeria as well as for other oil-producing countries. This paper updates a 2023 report on the behaviors of five super-emitter offshore flares operated by international oil companies that had revealed very high flaring levels. Analysis of recent satellite data up to June 2026 shows a mixed picture, with some improvement but also evidence of continued excess flaring behavior; three of the five flare sites are still classified as active global super-emitters. The paper highlights the inadequate determination of routine flaring that allows continuous flaring to sustain operations. It documents a practical method to measure routine flaring when defined as all flaring except for safety reasons. The paper analyzes the relationship between oil production and flaring and shows that high flare intensity correlates with high oil decline. Existing regulatory and financial incentives have not fostered good quality field operations to minimize flaring and optimize oil reserves; indeed, these five flaring sites combined are estimated to have incurred lost potential gas export sales value due to flaring of more than USD4 billion over their lifetimes.

This review is part of a broader CGD-EnergyCC research project examining the case for fiscal and regulatory measures to reduce gas flaring and venting in oil and gas producing countries. It is one of two papers dealing with Nigeria. Its companion paper—Nigeria: How Emissions Reduction Can Unlock Government Revenues—explores the scale and value of Nigeria's overall flaring performance and the opportunity to capture the value of the wasted gas. An earlier literature review synthesized the evidence on the human health impact of gas flaring, including in Nigeria. Two related blogs—COP30: Learning from Brazil's Experience Limiting Gas Flaring and Gas Flaring: A $100 Billion Problem with a Policy Solution—set out the project's core argument: that eliminating wasteful flaring is not an intractable technical problem but a policy failure, and that well-designed fiscal measures can simultaneously generate government revenue, improve public health, and advance climate commitments. This paper contains valuable evidence of the costly and persistent failures of governance and enforcement.

Mark Plant
Senior Fellow Emeritus, Center for Global Development

John Hicklin
Non-resident Fellow, Center for Global Development

Summary

In 2023, EnergyCC conducted a study with Oxford Policy Management Limited that documented the natural gas flaring performance of five Nigeria super-emitters during 2012–2022. This follow-up review, in collaboration with the Center for Global Development (CGD), is based on more than three years of additional performance data (from January 2023 to June 2026). The study evaluates in detail the gas flaring characteristics of the same five offshore super-emitters operated by four major International Oil Companies.

Natural gas flaring is usually portrayed as a necessary safety feature in oil development, providing the means to ensure fast depressurization of oil and gas facilities in case of process upsets. Continuous flaring is often seen as an 'early development' phenomenon, whereby gas development infrastructure lags the oil development. Atmospheric emissions from oil and gas installations are commonly referred to as 'leaks' with stakeholder focus on leak detection as the solution to arresting such emissions.

The study used VIIRS Nightfire (VNF) satellite data from Earth Observation Group, Payne Institute for Public Policy, that provides ubiquitous and long-term (since 2012) global gas flare data for detailed diagnostics and assessments. The data analyses provide **new insights into oil and gas emissions that contrast sharply with general perception**. Most gas flaring and venting occur not as leaks but as intentional disposal of natural gas as an unwanted byproduct of oil production. Gas flaring and venting continues for the duration of field life, frequently exceeding a 20-year lifespan. Rather than serving as a safety mechanism to halt oil production incidentally, most flaring occurs continuously to sustain operations, even if the facilities are impaired to process and preserve the associated gas produced with the oil.

Without proper understanding of the interrelationships between gas flaring and oil production processes, it is difficult to determine root causes, appropriate metrics and solutions. Voluntary measures focus on routine flaring, such as the World Bank Zero Routine Flaring by 2030 initiative. However, ambiguity exists on how to define and measure routine flaring, distinct from non-routine (safety) flaring. This significantly limits the scope and impact of flare reduction targets. To design effective impact metrics, regulators first need better insight into how gas flaring occurs throughout a field's operational life. Improved flare measurements, transparency and accountability are needed to reconcile observed differences between operator and satellite data.

By combining VIIRS flare datasets with oil production records, the **correlation between gas flaring and declining oil production** can be quantified. Good quality field operations optimize oil reserves and coincide with low or zero routine flaring. Conversely, data analytics show that in periods of prolonged high flare intensity, oil production declines faster (with 0.64 correlation factor), potentially compromising oil ultimate recovery. The relationship between gas flaring and oil decline is complex and each asset has its own specific relationship between oil decline and flare intensity. For all five assets

combined, annual average flare intensities below 19 m^3 of gas flared per m^3 of oil produced do not exhibit incremental oil decline, while at 30 m^3/m^3 the annual oil decline is 8.2%. Despite potential multi-causality in the flare intensity-oil decline relationship, the financial stakes are profound. In 2025, the accelerated oil production decline from high flaring intensity was 8.6%, exceeding an average field decline of 5%. The estimated oil value loss due to the additional 3.6% decline is USD 217 million (at an assumed oil price of USD 60/bbl) and is incremental to the flare volume losses assessed.

This work demonstrates new insights on natural gas flaring, relevant for oil and gas stakeholders, regulators, investors, and revenue/tax authorities. Using flare and production performance data of five offshore Nigeria super-emitters (Agbami, Yoho, Usan, Abo, Bonga), a **methodology was developed to distinguish routine flaring** (i.e. flaring to produce) from non-routine flaring (i.e. flaring to safely stop production). This simple and transparent methodology is applicable for continuous flare measurements (metered gas flares) as well as intermittent measurements (VIIRS VNF satellite data). For the five assets, routine flaring takes up the following volume shares of all flaring since 2012: Agbami (63%), Yoho (61%), Usan (74%), Abo (75%), and Bonga (59%). In the period May 2024–April 2025, Bonga managed to reduce its routine flaring to 34.8%, at much reduced flare rates. The calculated volume of routine flaring significantly exceeds industry-reported figures. This discrepancy arises, in part, because operators classify continuous production during equipment outages as non-routine flaring.

Over their operational lifetimes to date, these five assets have incurred an estimated USD 4.3 billion in potential gas export sales value losses due to flaring. The flaring lifecycle observed from the Nigeria super-emitters follows a distinct pattern, when value loss (in USD) and energy loss (as percentage of crude energy produced) are tracked over time. Both parameters are critical for (fiscal) revenues and efficient energy utilization. The impact of natural gas flaring is substantial. For example, value loss from a single gas flare (Agbami in 2018) can be as high as USD 160 million per year, while the gas flaring energy loss can be as high as 35% of the energy content of the crude produced (Abo in 2023). Regulators should monitor flare rates (value loss) as well as flare intensity (energy efficiency) simultaneously and set (mandatory) performance standards for both. These (and other) regulatory measures to ensure low oil and gas emissions, from existing and new developments, should be designed into enforceable policies.

The review shows a range of outcomes between assets. Compared to the 2020–2022 period, Bonga flare rate improved the most during 2023–2025 with 77% reduction in flaring, followed by Agbami (–57%). Gas flaring from Abo (–6%) and Usan (+8%) stayed more or less constant, while Yoho increased (+25%). It is worth noting that after operatorship was handed over from Exxon to Seplat in December 2024, Yoho produced at a significantly lower flare rate (–45%) compared to the two years period prior. Unfortunately, Yoho suffered a fire in September 2025 and the asset has remained closed since for repairs and upgrades. Hence the period of comparison between the two different operators is limited. Between 2022 and 2025, the five assets combined showed a 21% flaring reduction, compared to an overall increase in

Nigeria country gas flaring of 30%. Among the five assets, Usan ranked fourth in 2022 and rose to the top spot in 2025, flaring eight times as much as fifth ranked Bonga. This range of outcomes demonstrates that with infrastructure investments and good operational policies **it is possible to significantly reduce gas flaring** (Bonga, Agbami). However, not all operators delivered as good operational quality as shown by the gas flaring results. Assets that face potential transfer (or termination) of ownership noticeably increase gas flaring, as maintenance reduces and oil production exceeds sustainable limits.

Periods of fiscal and commercial uncertainty have also had a direct impact on the assets' flaring performance. Several years before production licenses were due to expire, and when facing commercial disputes, license holders were reluctant to invest in asset integrity interventions, repairs, production improvement, and flaring reduction measures. Flare analysis reflects this, showing significantly higher flare rates before license extensions than after. Hence, there are hidden costs to commercial and legal disputes that affect oil production decline (and reserves) and gas wastage due to flaring, impairing current and future taxable income. The resolution of aforementioned disputes and the frame work under Nigeria's Petroleum Industry Act (PIA) that became operational in August 2022, has restored a more stable investment climate that has since unlocked significant investments.

This study includes for each of the five assets a quantitative analysis of natural gas flaring impact on financial value loss, relative energy loss and oil decline across the asset life cycle. In addition, the routine flaring assessment method was developed and tested against the flaring performance of the five offshore assets. Except for Bonga, the other three currently producing assets (Agbami, Abo, Usan) continue to be **classified as global super-emitters**, i.e. part of the global top 300 flares.

Beyond the immediate scope of this analysis, the broader implications of natural gas flaring extend significantly further, given its well-documented adverse effects on public health, global climate dynamics, energy security, and agricultural food systems. Therefore, comprehensive assessments must integrate flaring quality metrics—such as combustion effectiveness—in addition to conventional flaring volumes. This paper does not account for the revenue losses or broader detrimental effects of gas venting, despite their acknowledged significance within oil and gas operations, and as documented by UNU-WIDER papers.

Reviews and feedback

In preparation for publication of this work, draft copies of the paper were sent for CGD-internal and anonymous external peer review. Draft versions of the paper were also sent for comments to the Government of Nigeria (Federal Ministry of Finance) and the following companies: Chevron, ENI, Exxon, Shell, and TotalEnergies.

We are grateful for the feedback received on our work through discussions and written comments. The Nigerian Government has helped to provide focus on the implementation requirements for the methane fee and rebate scheme. We have reflected this input in the final version of the paper. The five companies acknowledged to having received the draft paper and two companies (Shell and TotalEnergies) have sent substantive written comments. Exxon and Chevron appreciated the opportunity for review and to be consulted, and declined to offer comments.

Additional information provided by Shell and Total has been incorporated in the final version of the paper. Both companies mentioned to use voluntary GFMR definitions to define their routine flaring emissions. The authors maintain that routine flaring needs further restraint beyond the GFMR definition that addresses only 30 percent of companies' reported flaring.

To effectively reduce flaring and venting emissions, there is a clear need for deeper dialogue between industry players and governing bodies to align their measures and strategies. The OGDC-2025-Status-Report.pdf highlights challenges in aggregating companies' GHG emissions data, having "different starting points, reporting practices and requirements, be they regulatory, shareholder/stakeholder expectations or historical corporate practices".

It is encouraging to note that "TotalEnergies supports performance standards based on robust monitoring, reporting and verification frameworks and policies to measure and reduce methane emissions. TotalEnergies considers that such policy frameworks should also take into account the imperatives of energy security and affordability. As such, TotalEnergies supports the development of regulations that aim to reduce methane emissions sector wide …". Meanwhile, "Shell advocates putting a direct price on carbon emissions as part of a broader policy framework to achieve net-zero emissions. Additionally, market-based mechanisms, such as an emissions trading system, incentivise decarbonisation at the lowest cost, and support the long-term development of a global carbon market." It is the authors' view that voluntary measures for emissions reduction have to date not delivered on their promise. Moreover, financial mechanisms to incentivise flaring reductions at source (such as the methane fee and rebate scheme) are more effective and directly beneficial for countries, such as Nigeria, where such emissions occur.

1. Introduction to the super-emitter performance study

Following EnergyCC's 2022 study with Oxford Policy Management Limited (OPM)[1] that documented the flaring performance of Nigeria's super-emitters, a follow up review has now been conducted in collaboration with the Center for Global Development (CGD) using more than three years of additional performance data (from January 2023 to June 2026).

The offshore study is based on five assets, in order of historic flaring volumes: Agbami, Yoho, Usan, Abo, and Bonga that are operated by Chevron, Exxon (Seplat from 2025), Exxon (TotalEnergies before 2015), ENI and Shell, respectively.[2] Apart from Yoho, the assets are located in deepwater areas ranging 500 m to 1500 m water depth. The high cost of deepwater developments poses specific challenges that require high quality of operations. The development of each of these assets stipulated zero routine flaring, with produced gas to be exported to shore (Bonga) or reinjected for future exploitation.

The contribution of the five offshore super-emitters to Nigeria's total oil production and gas flaring has decreased in recent years. At their peak these five offshore assets contributed a third to Nigeria's oil production and 14% of flaring. In 2025, they represented 15% of Nigeria's production and 6% of flaring. With oil production ongoing for 13 to 23 years these assets are now mature with more than 80% of their developed oil ultimate recovery already produced.

The analysis of the late-life production and atmospheric emissions of these assets provides insight into the efficiency of tail-end oil recovery and the effectiveness in preserving natural gas for the next phase of reservoir development, i.e. gas blowdown.[3] While each of these offshore assets is operated by a major International Oil Company (IOC) that has international operations standards, key differences in production policies can be observed. Although each development behaves differently based on reservoir and fluid properties, reservoir drive (see Box A), and development strategy, the objectives for each of these assets are similar: the commercial development of hydrocarbons in a safe and environmentally prudent manner that maximizes asset value, optimizes ultimate recovery and minimizes waste. Quality of operations is essential to meet these development objectives. Natural gas flaring is a key indicator for quality of operations to optimize hydrocarbon production and ultimate recovery.

1 The OPML Nigeria study was part of the Facility for Oil Sector Transparency and Reform (FOSTER) programme, funded by the UK Government, https://energycc.com/news/energycc-major-studies-on-nigeria-super-emitters-published-by-oxford-policy-management.html.

2 Exxon sold its working interest in Yoho to Seplat Energy and operatorship was transferred in December 2024. Yoho FPSO suffered a fire on 27 September 2025 and the asset remains closed in since for repairs and upgrades. Hence, most of Yoho's performance is attributed to the period when Exxon was operating the asset.

3 Gas blowdown is the final phase of an oil field production cycle, when the recovery focus changes from oil to gas production to extract the remaining value from the field.

Box A: Reservoir drive is the combination of fluid dynamics that provides energy for oil to flow to producing wells and to lift reservoir fluids to surface. Reservoir drive methods include depletion drive (oil expansion as reservoir pressure declines), aquifer drive (pressure support from a large water source connected to the oil reservoir), gas cap drive (if a gas resource overlays and is in pressure communication with an oil reservoir) and energy support from secondary development options such as gas injection, water injection, or both. The type of reservoir drive and how this is managed during production operations determines how much oil can be recovered from a reservoir (i.e. its ultimate recovery). The efficiency of the reservoir recovery process is expressed as the recovery factor (RF), the volume of oil to be ultimately recovered from the reservoir divided by the oil volume initially in place. For depletion drive, the oil RF is generally less than ~12%, for gas cap drive it is typically 20% to 30%, aquifer drive 25% to 40% and secondary water and/or gas injection can increase RF up to ~50% depending on reservoir quality and connectivity. Nigeria's deepwater oil recovery factor is estimated to average between 30% and 45% over the lifecycle of a field.

The amount of gas present in the oil reservoir is an important contributor to the total energy of the system. It includes the component of reservoir gas that is dissolved in the oil at reservoir conditions (solution gas). A higher content of solution gas lowers the viscosity of the oil, enabling it to flow more easily (and with a smaller pressure drop) towards the producer wells. When travelling inside production wells from reservoir depths (1,500 m to 3,800 m) to the production facilities at surface, gas will come out of solution and the buoyancy of these gas bubbles provides lift for the crude to flow up.

When producer wells pull too hard (i.e. produce at excessive rates) the pressure around the well bore drops and gas comes out of solution as free reservoir gas. The mobility of reservoir gas is much higher than that of oil and consequently oil wells will produce at surface a mixture of depressurized crude, solution gas and free reservoir gas. Associated gas is the combination of solution gas and free gas produced together with the oil. Production of large amounts of free gas by producing oil wells has many negative consequences:

- Reservoir pressure drops and the overall level of reservoir energy declines prematurely in the oil recovery lifecycle.
- Oil viscosity increases in situ, making it harder for oil to flow and lowering the oil production rate.
- The pressure drop around well bores increases, causing a negative cycle of increased free gas production (measured as Gas-Oil Ratio, GOR), further lowering reservoir energy.
- A secondary gas cap may form in the reservoir transmitting the pressure declines more easily across the extent of the reservoir, affecting the total reservoir production system.

- An imbalance in reservoir pressures may cause the oil rim to move away from the oil well completions, lowering their ultimate recovery.
- Oil rim thinning is likely to occur causing increased gas and water coning (vertical) and cusping (lateral) towards the wellbore, lowering recovery factors while increasing flow instabilities and topside production process challenges (process trips and gas flaring).

Therefore, matching well offtake rates (by choking) with reservoir delivery rates is essential for high quality oil operations. When wells are pulled too hard to produce more oil, the excess gas needs to be reinjected (lowering process efficiency) or flared (when process system cannot cope with the excess gas). Reservoir delivery rates decline faster in consequence, exacerbating free gas production in a negative spiral. Ultimate recovery will be impaired and recovery factors decline. This makes gas flaring measurement an important factor in determining quality of operations and optimising ultimate recovery for both oil and gas.

To assess the emissions performance of these Nigeria assets, data provided by the VIIRS Nightfire (VNF) satellites were used as a diagnostic tool to measure and assess flares. This work has been made possible with the welcome support from the Earth Observation Group, Payne Institute for Public Policy.[4] With recent upgrades in VIIRS-VNF flare assessment algorithms,[5] EnergyCC has reviewed and updated its calibration algorithms. The improved flare analysis has been used for the full assessment period from March 2012 to June 2026. Minor differences in results may be observed between the previous OPM study and current CGD work. However, these are not material in relation to the outcomes of current (CGD) and previous (OPM) studies.

In addition to extending the period of observation with the latest three years, the current study also aims to address the following objectives:

- To what degree have the IOCs' measures and plans documented in response to the OPM reports been implemented.
- How has flaring performance for these assets changed in the period after the OPM study (January 2023–June 2026).
- With oil production increasingly mature, how has flare intensity been managed by the asset operators.[6]
- How do flaring emissions compare with companies' performance standards.

4 Elvidge, Christopher D., Mikhail Zhizhin, Feng-Chi Hsu, and Kimberly E. Baugh. "VIIRS nightfire: Satellite pyrometry at night." Remote Sensing 5, no. 9 (2013): 4423–4449.

5 https://www.worldbank.org/en/programs/gasflaringreduction/brief/updating-the-global-gas-flaring-tracker-methodology.

6 Flare intensity is an efficiency measure defined as the volume flared divided by the oil volume produced (m^3/m^3). A high flare intensity results in more gas flared per volume of oil produced.

- Has routine flaring been reduced consistently with IOCs' corporate objectives and in line with The World Bank's '*Zero Routine Flaring by 2030*' initiative.[7]
- How does natural gas flaring relate to oil production decline: is flaring intensity a useful measure to assess quality of operations in terms of oil production declines.

Routine gas flaring is seen as a practice that wastes natural gas as an energy resource. The CGD study also builds on the earlier OPM work by assessing how excessive gas flaring is related to increased oil decline rates. Hence, gas flaring measures not only natural gas wastage, but may also indicate compromised oil rates and reduced ultimate recovery.

For the purposes of this study, we define **routine flaring** as all flaring that is conducted to continue oil operations. **Non-routine incidental flaring** occurs when the oil and gas process equipment trips or undergoes an emergency shutdown, and is conducted **to safely stop oil operations**. These flaring definitions differ between companies: some companies define three categories of flaring: routine flaring, non-routine flaring and safety flaring. However, the non-routine flaring category is unnecessary. It causes ambiguity in flare types, and reduces the impact of flaring reduction targets that focus only on routine flaring.

In our analysis, the observable signature of (non-routine) safety flaring is treated distinctly from routine flaring. Safety flaring is measured as sharp peaks in individual flare rate observations from VIIRS.[8] Flare variability is a measure that calculates irregularity in gas flaring and is defined as the maximum daily VIIRS flare rate in a month divided by the monthly average VIIRS flare rate. Hence, non-routine flaring has high variability. Furthermore, safety flaring coincides with a temporary shut-down of oil production and hence these events cause a short duration dip in oil production.

Conversely, routine flaring has low variability and increased routine flaring often coincides initially with higher oil rates followed by prolonged higher oil declines (see Box A).

This paper is structured into the following sections (by number) as follows:

2. After this introduction section, context is provided in terms of Nigeria's overall flaring performance trends and ranking of its largest flaring emitters.
3. This is followed by a discussion of the high-level outcomes of the updated flaring analysis for the five offshore assets.
4. To support understanding of gas flaring performance, a life-cycle flaring performance model is presented in the subsequent section. This model is based on two key parameters, gas value loss and relative energy loss from flaring. The model is applied to each of the five offshore assets.
5. Two key flare performance measures, flare variability and flare intensity, are discussed and assessed for the five assets. Overall trends are evaluated.

7 https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/about.

8 The same is true when analysing metered flare data and hence the flare rate assessment method can be applied for VIIRS and metered data alike.

6. The concept of routine flaring is discussed and a model introduced that differentiates routine from non-routine flaring in (metered or satellite) flare rate measurements. The model is then applied to the five assets and routine flaring trends are evaluated.
7. The relationship between flare intensity and oil production decline is presented and applied for the five assets, making a link to flaring intensity as a measure of operational quality.
8. Finally, the flaring performance for each of the five offshore is discussed and relevant observations highlighted.
9. The paper ends with a conclusion section setting out the key outcomes of the study.

2. Nigeria flaring performance history

Nigeria has historically been one the world largest contributors to global natural gas flaring. In 2005, the country ranked second after Russia (see Figure 1a). Associated gas monetization projects, including Nigeria LNG (NLNG), helped to reduce Nigeria's flaring. In 2024 the country ranked 8th (based on combined flare emissions for the period 2005–2024, Nigeria ranked fourth globally). As can be seen from the graphs, Nigeria is one of the few countries able to decrease flaring, mostly during the period 2005–2015, only Russia established a larger decrease in flaring. In recent years, Nigeria's flaring increased again, a trend that is shared with many large flaring countries.

FIGURE 1. Oil production and flare rates for the largest contributing countries 2005–2024

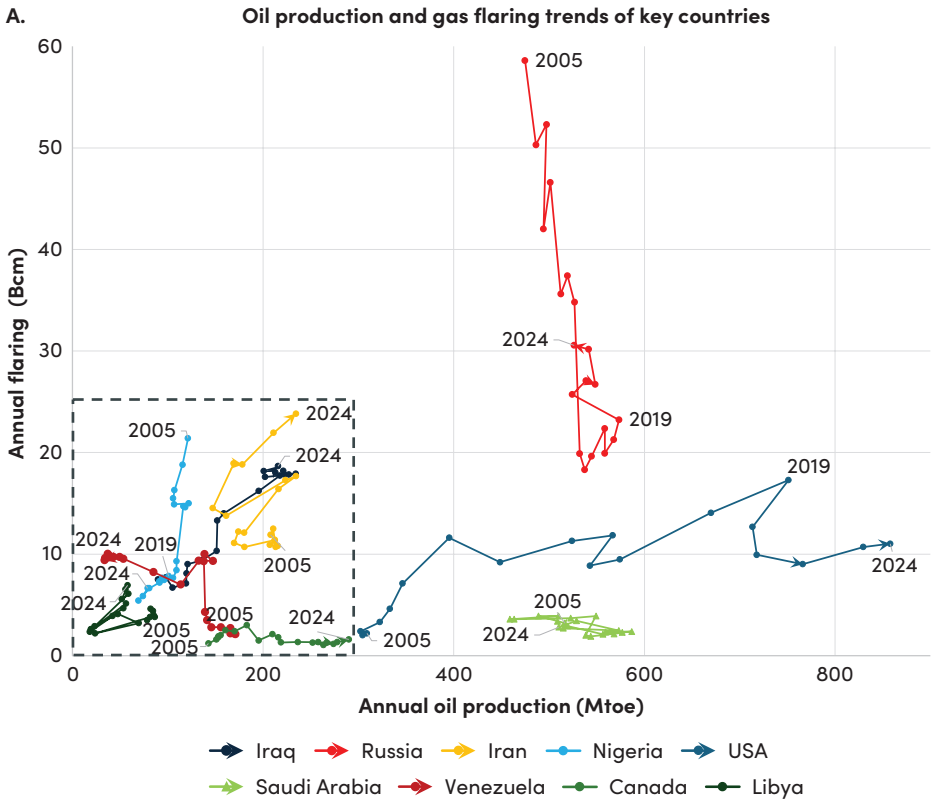
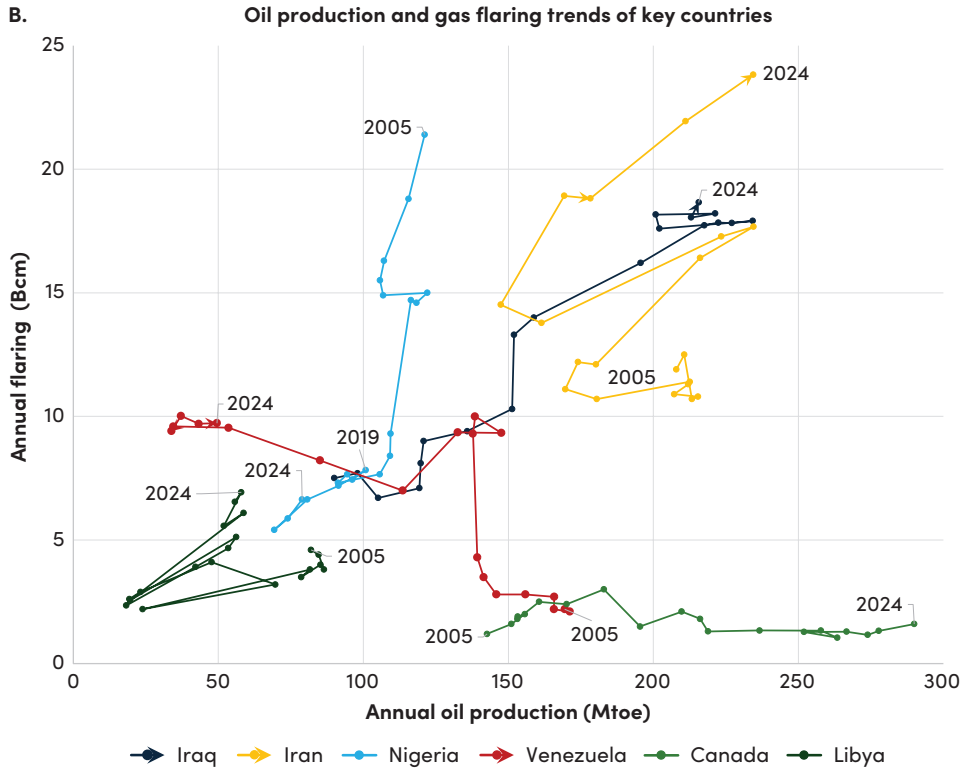


FIGURE 1. (Continued)



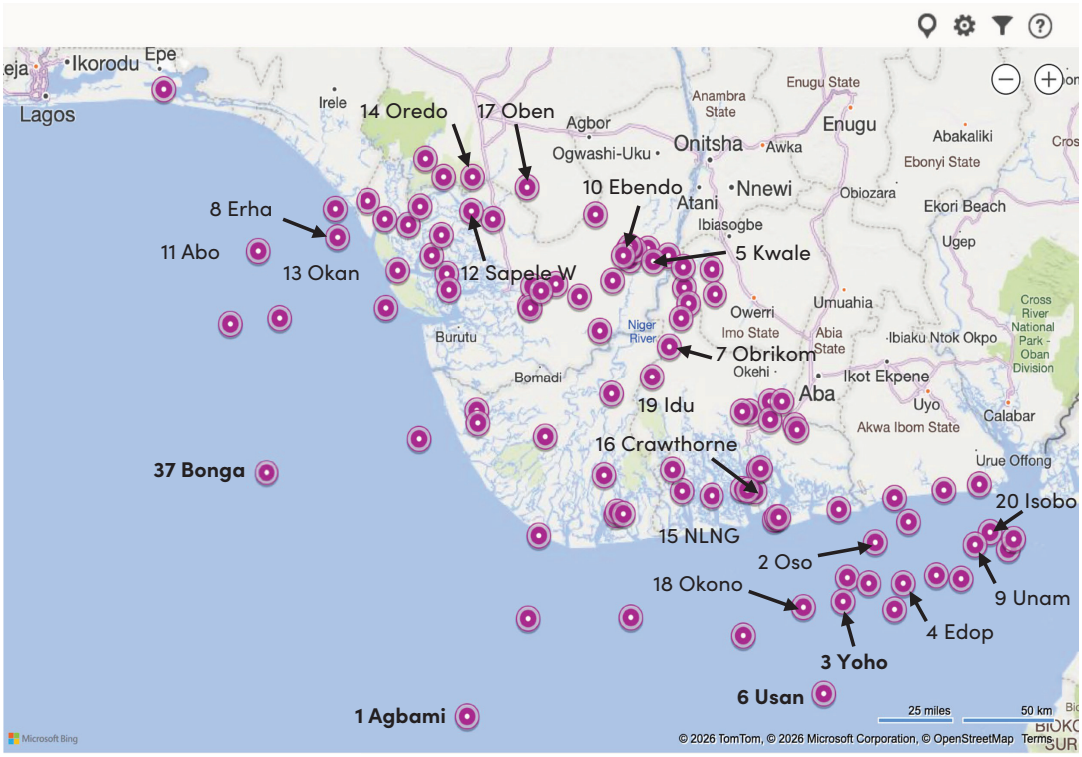
Notes: Author's illustration, flare data from VIIRS, production data from oil data from Energy Institute.[9] Figure 1a (top), enlarged detail Figure 1b (bottom).

In the period since 2012, 500 individual Nigeria flares were detected and assessed using VIIRS. A large number of these have been flaring continuously. Figures 2 and 3 show Nigeria's largest flares. Among the top-20 flares 9 are located onshore and 11 offshore. The flares evaluated in detail in this study are shown in **bold**, with Agbami ranked as Nigeria's largest, Yoho 3rd, Usan 6th, Abo 11th, and Bonga 37th.[10] Apart from Usan, the other assets started production earlier and hence these assets had flare emissions from before 2012.

9 Energy Institute – Statistical Review of World Energy 2025, https://www.energyinst.org/statistical-review.

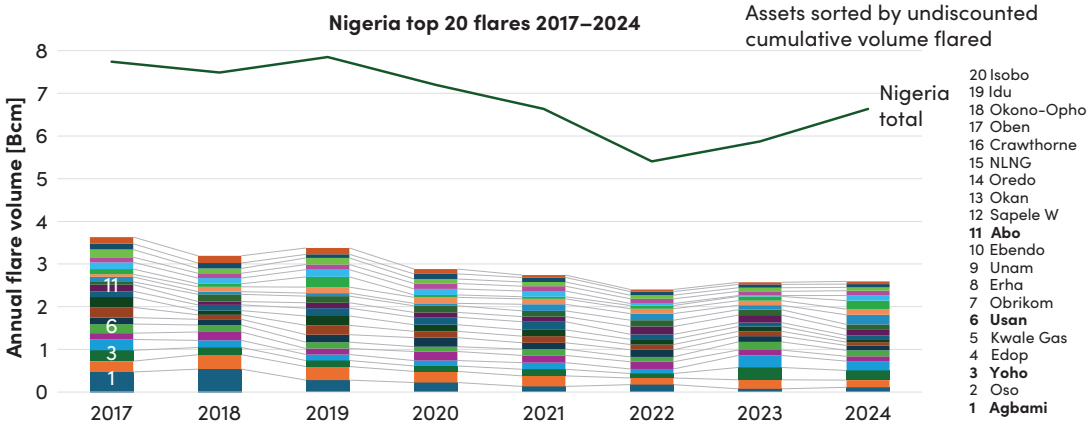
10 Ranking based on undiscounted cumulative gas volume flared in the period 2017–2024.

FIGURE 2. Nigeria's largest 100 flares by location in the period 2017–2024



Notes: Author's illustration, flare data from VIIRS. Top 20 flares and Bonga identified by name.

FIGURE 3. Nigeria's largest flare rates in the period 2017–2024

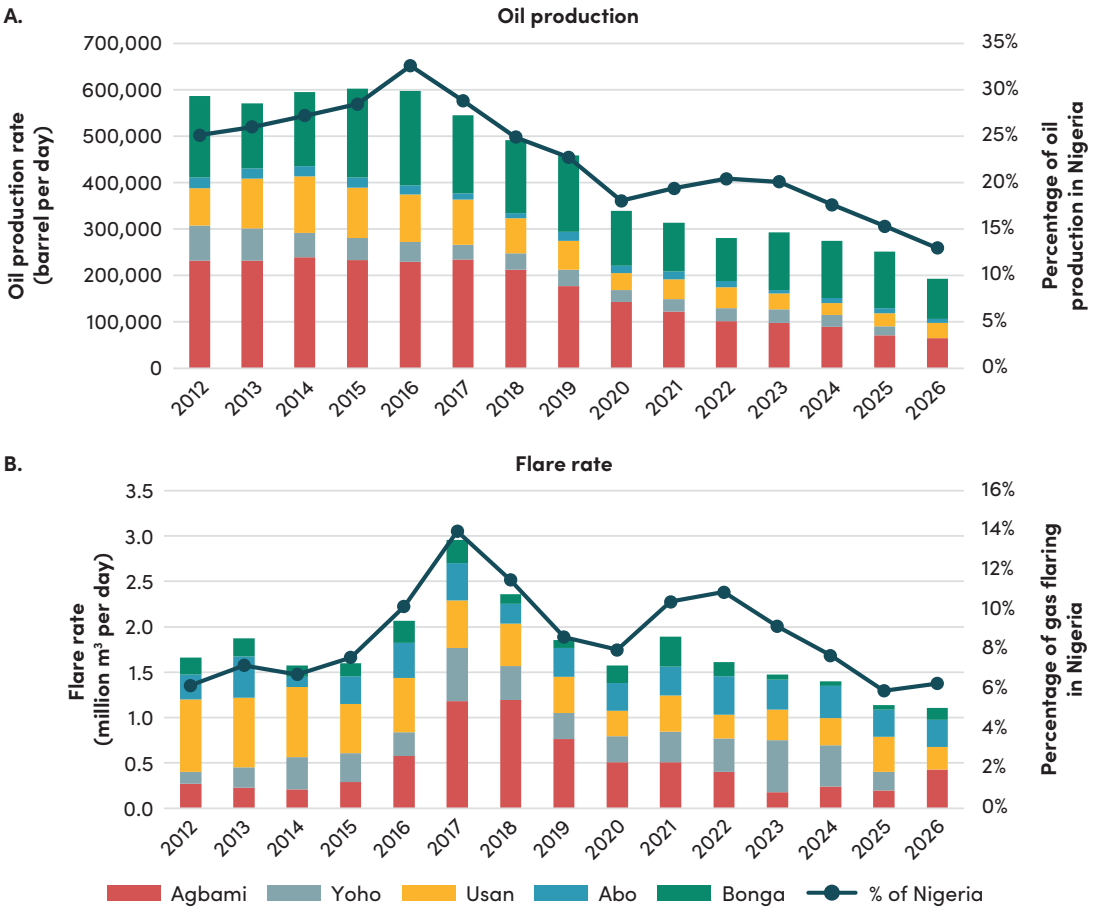


Notes: Author's illustration; flare data from VIIRS. Bonga, not included in the data columns, ranked 37th among Nigeria flares overall in the period 2017–2024, and ranked 16th highest in 2021.

3. Super-emitter operations performance overview

Using a similar methodology and metrics as for the 2022 OPM study, the performance review of the five Nigeria offshore assets has been extended to cover the most recent production period up to June 2026, see Figures 4a and b.

FIGURE 4. (a) Oil production and (b) flare rates for the five offshore assets



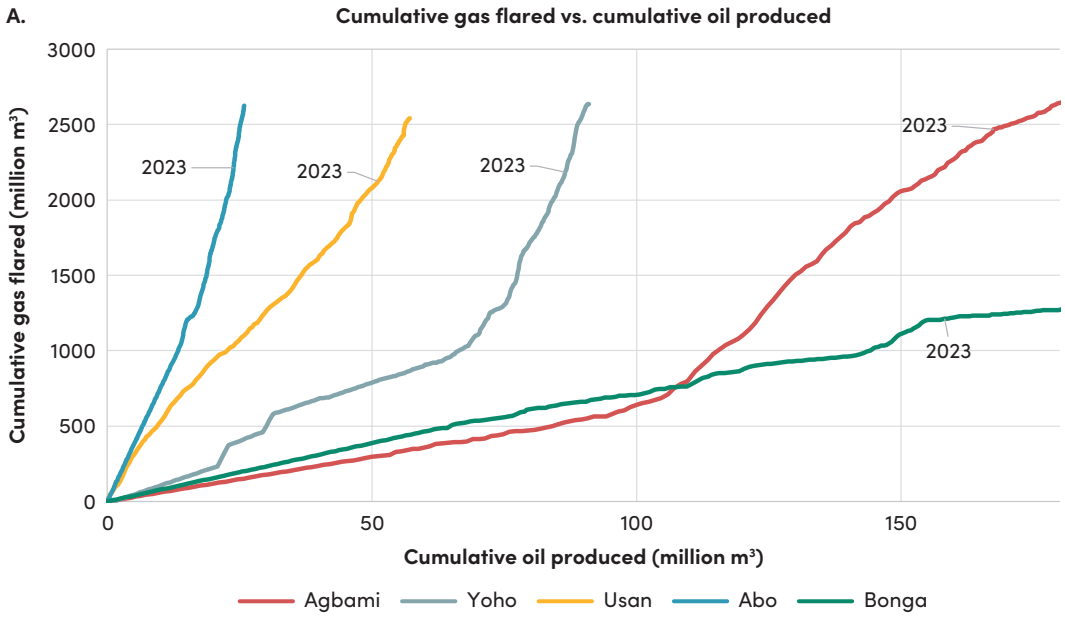
Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/. Data up to June 2026.

The contribution of these five assets to Nigeria's oil production and gas flaring has decreased in recent years. At their peak these five offshore assets contributed a third to Nigeria's oil production and 14% of flaring. In 2025, they represented 15% of Nigeria's production and 6% of flaring (among 500 active flares during the period). On 27 September 2025, Yoho FPSO suffered a fire and the asset remained shut since for repairs and upgrades. Yoho's unavailability contributes to the 2025 and 2026 declines in oil production and flaring.

Natural gas flaring occurs throughout the production lifecycle, but assets show differences in trends as shown in Figure 5a. With the exception of Bonga, the other 4 assets have flared similar cumulative volumes of gas, but with large differences in volumes of oil recovered, that are reflected in very different indicators of flaring intensity. By June 2026, Agbami had recovered 184.24 million m^3 (1.16 billion barrel) compared to Abo 25.91 million m^3 (162.9 million barrel). Hence, Abo's average flare intensity 101 m^3/m^3 much exceeds Agbami's 15 m^3/m^3. By contrast, Bonga has the lowest average flare intensity of 7 m^3/m^3. To put these values in perspective, Abo's energy content of 101 m^3 of gas lost is 0.2 megawatt hours (MWh) for each 1 m^3 of crude (1.67 MWh) produced. The average flare gas energy loss for Abo during its production lifecycle to date is 12% of the crude oil energy produced. If monetized, the value of gas flared (i.e. lost) per barrel of Abo oil produced is USD 2.00 or USD 5.71 based on domestic (USD 2.92/MMBtu) and LNG export gas[11] prices (USD 10/MMBtu), respectively.

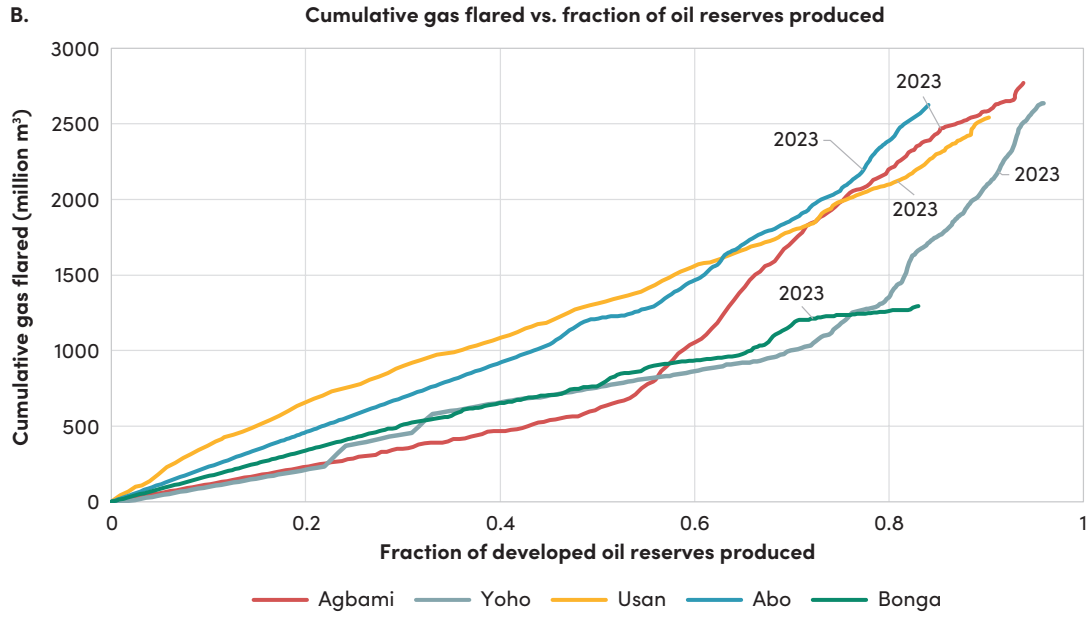
In 2023, Abo's flare intensity was 287 m^3/m^3, resulting in a **gas energy loss of 35%** of the energy of each barrel of oil produced. This equates to a gas flare value loss of USD 16.76/bbl of Abo produced oil, at a USD 10/MMBtu LNG export price. Abo produced at an average rate of 7,130 barrel of oil per day in 2023, causing a gas value loss of USD 44 million that year.

FIGURE 5. Oil production and flare trends for the offshore assets (a top, b bottom)



11 The value calculation accounts for the LNG liquefaction process consuming 16.14% of gas supplied.

FIGURE 5. (Continued)



Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/. Data up to June 2026, new data from January 2023.

Figure 5b normalizes flare performance trends for differences in developed ultimate oil recovery. It shows volume of gas flared as a function of production maturity, expressed as the fraction of developed oil reserves[12] already produced. The general trend is that flaring intensity increases with an increasing fraction of developed reserves already produced. Agbami, Yoho and Bonga initially show a comparable trend in volumes flared, different from Usan and Abo that had a steeper slope of gas flared. During the second half of the oil recovery period, Agbami and Yoho flaring increased towards the curves of Usan and Abo. Only Bonga remained on its trend, despite a period from 2021 to 2022 when gas export constraints due to equipment failures caused increased flaring.

As late field life flaring intensity increases, the question arises as to whether continuing oil production at high flare intensities is the optimum development choice. The alternative is to switch from an oil development to a gas development scenario, as is being planned for Yoho. Such a gas 'blowdown' scenario optimizes gas instead of oil recovery, although liquids[13] continue to be produced. Additional gas treatment and compression equipment are needed to handle the increased gas volumes and process the gas to the right specification for Floating LNG (FLNG) export or connection to the gas aggregation pipeline network to shore.

12 The developed oil reserves have been estimated for each field based on decline curve analysis, described later in this paper.

13 Liquids include remaining production from oil completions complemented with Natural Gas Liquids (NGLs, not to be confused with LNG) from the produced wet gas.

New reservoir completions may be needed to optimise gas production rates. Existing oil completions could continue to operate, but at a certain point these may water out or face lift constraints due to increasing watercut and declining reservoir pressures. Commerciality of oil-to-gas redevelopment obviously benefits from maintaining sufficient gas resource volumes in the reservoir through reinjection instead of flaring throughout the production lifetime. Agbami, Yoho, Usan, and Abo have each flared more that 2,500 million m^3 (~0.1 trillion cubic feet, Tcf) of gas to date. An FLNG development requires 0.5–2 Tcf+ of gas reserves and hence gas may have to be aggregated across several mature fields. Additional new gas discoveries could also be developed and tied-in to the offshore gas processing hub.

As mentioned, the Yoho field is to transition from an oil field into a gas field. The project is Nigeria's first indigenous FLNG facility, developed by UTM Offshore (72%) in partnership with NNPC (20%) and Delta State Government (8%). In September 2024, UTM Offshore Limited obtained the license to operate the new 2.8 mtpa FLNG plant, upgraded from 1.2 mtpa. Engineering work is expected to conclude in 2028, with LNG production due to start in 2029. Afreximbank provided USD 2.1 billion financing and committed a further USD 3 billion.[14]

4. Super-emitter flaring energy and value loss assessment

Tables 1 and 2 detail the annual energy loss and commercial value loss at gas export prices (assuming LNG export at USD 10/MMBtu), respectively. Figure 6 shows that Abo flaring had the largest relative energy loss (in 2023), and Agbami the largest value loss (in 2017, 2018).

14 https://www.reuters.com/business/energy/nigeria-licenses-first-floating-lng-plant-export-domestic-use-2024-09-06/.

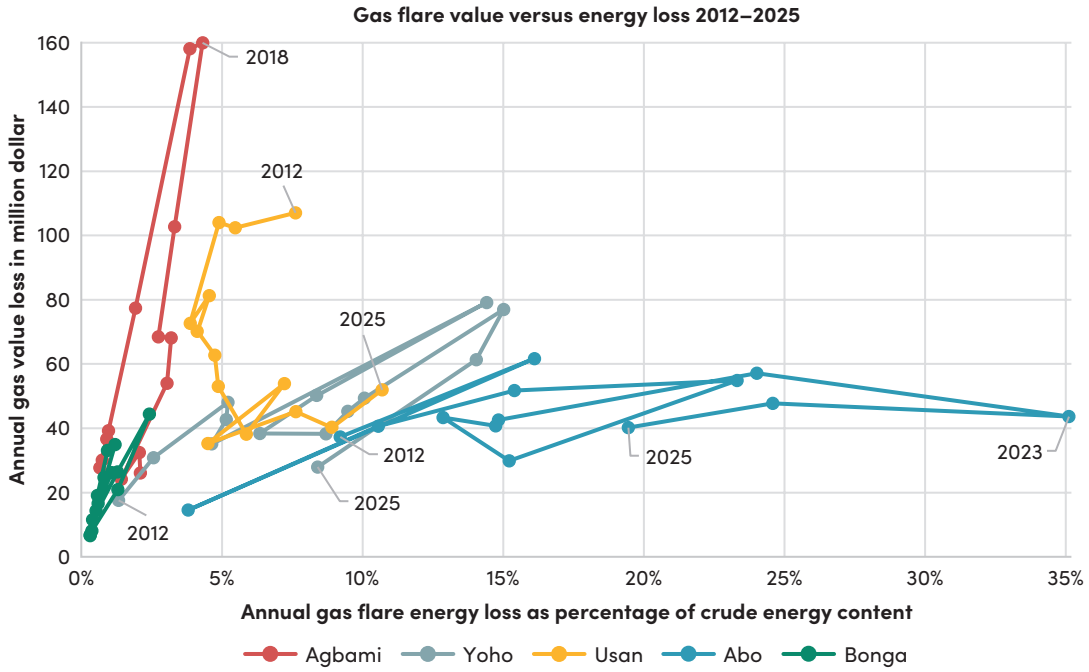
TABLE 1. Energy losses from gas flaring as percentage of the energy value of crude produced

Energy Loss	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026 ytd	Field Life
Agbami	0.90%	0.74%	0.66%	0.96%	1.93%	3.87%	4.31%	3.32%	2.74%	3.20%	3.05%	1.42%	2.07%	2.10%	5.03%	1.83%
Yoho	1.33%	2.57%	5.21%	5.15%	4.64%	14.42%	8.37%	6.35%	8.70%	9.47%	10.06%	15.01%	14.04%	8.40%	0.00%	3.55%
Usan	7.61%	5.47%	4.89%	3.87%	4.55%	4.13%	4.74%	4.88%	5.87%	7.22%	4.50%	7.63%	8.90%	10.70%	5.94%	5.45%
Abo	9.21%	16.11%	3.80%	10.56%	15.39%	23.32%	15.21%	12.86%	14.73%	14.84%	24.01%	35.11%	24.58%	19.45%	28.98%	12.36%
Bonga	0.80%	1.08%	0.60%	0.57%	0.93%	1.20%	0.52%	0.40%	1.29%	2.43%	1.29%	0.37%	0.32%	0.31%	1.18%	0.87%
Combined	2.18%	2.53%	2.03%	2.04%	2.67%	4.18%	3.70%	3.12%	3.58%	4.65%	4.42%	3.88%	3.92%	3.49%	4.42%	2.69%

TABLE 2. Value losses (in USD mln) from gas flaring at LNG export price of USD 10/MMBtu

Value Loss ($ mln)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026 ytd	Field Life
Agbami	$37	$30	$28	$39	$77	$158	$160	$103	$68	$68	$54	$24	$32	$26	$19	$1,012
Yoho	$18	$31	$48	$43	$35	$79	$50	$38	$38	$45	$49	$77	$61	$28	$0	$970
Usan	$107	$102	$104	$73	$81	$70	$63	$53	$38	$54	$35	$45	$40	$52	$11	$931
Abo	$37	$62	$15	$41	$52	$55	$30	$43	$41	$43	$57	$44	$48	$40	$13	$957
Bonga	$25	$26	$17	$19	$33	$35	$14	$12	$26	$44	$21	$8	$7	$7	$6	$474
Combined	$223	$251	$211	$214	$278	$397	$317	$249	$212	$254	$217	$198	$189	$153	$149	$4,344

FIGURE 6. Gas flare energy and value loss trends for each of the five offshore assets



Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/. Abo had a five-month shutdown in 2023.

The total flaring value loss from the five assets to date exceeds USD 4.3 billion and was USD 153 million in 2025. Figures 7a and b shows the assets' combined 2012–2025 trend.

FIGURE 7. Gas flare energy and value loss trends for the five offshore assets combined

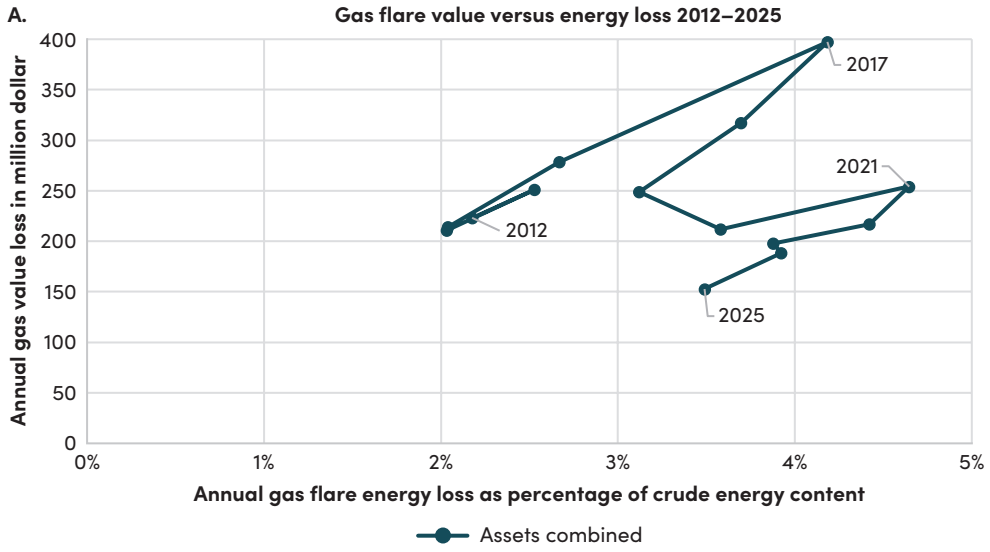
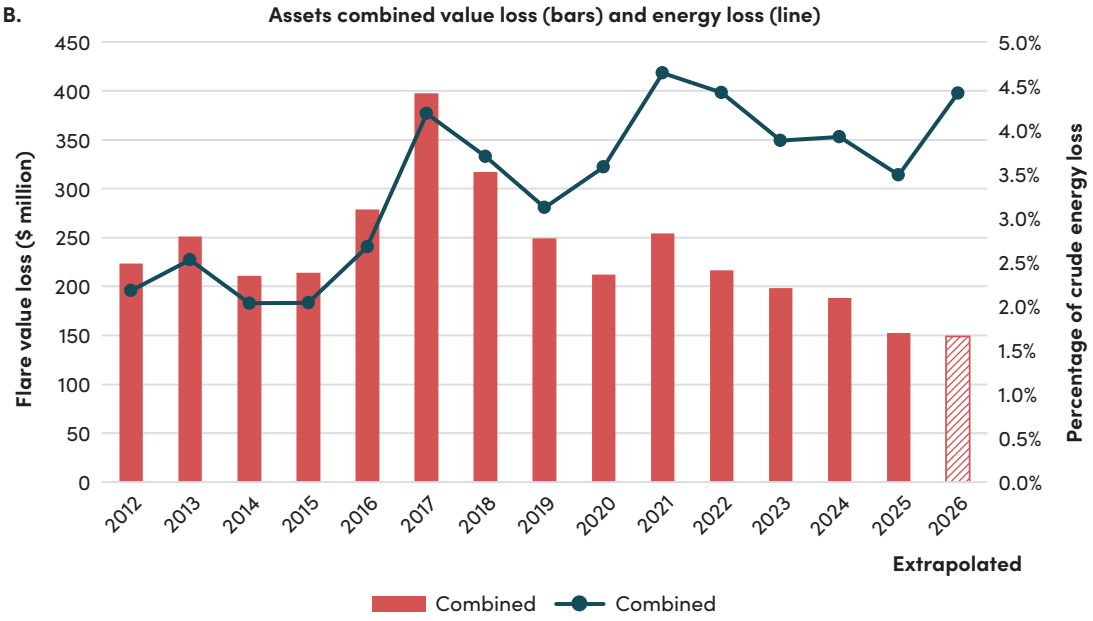


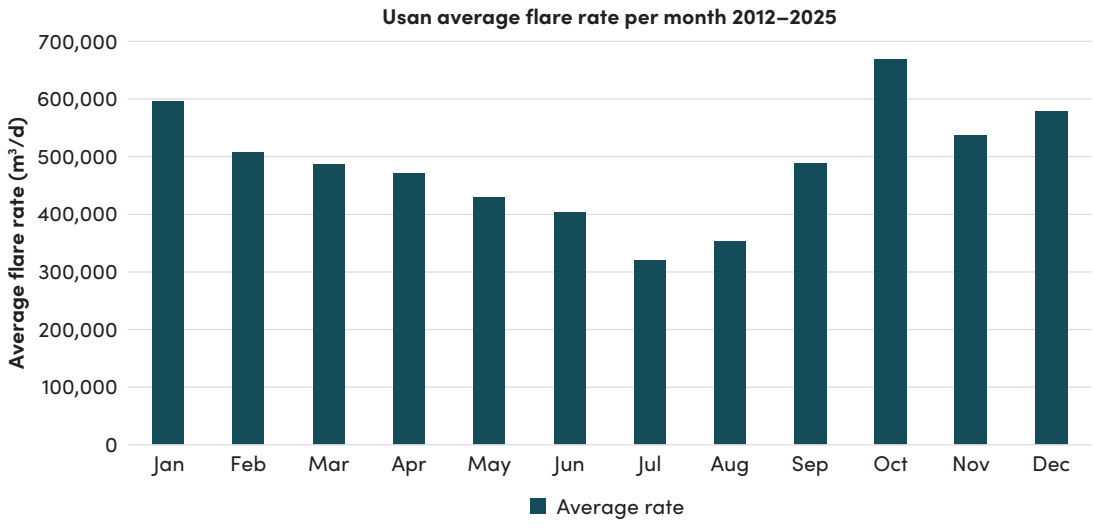
FIGURE 7. (Continued)



Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/. Figure 7a top, 7b bottom. Value loss for 2026 in Figure 7b is extrapolated based on 2026 data from January to June.

Partial data for 2026 are expected to be influenced by seasonality effects in the early months of the year when most maintenance activities and shutdowns are taking place. Seasonal weather variations (clouds) can affect flare detection and flare rates as shown in Figure 8.

FIGURE 8. Seasonal flare rate variations for Usan (2012–2025)

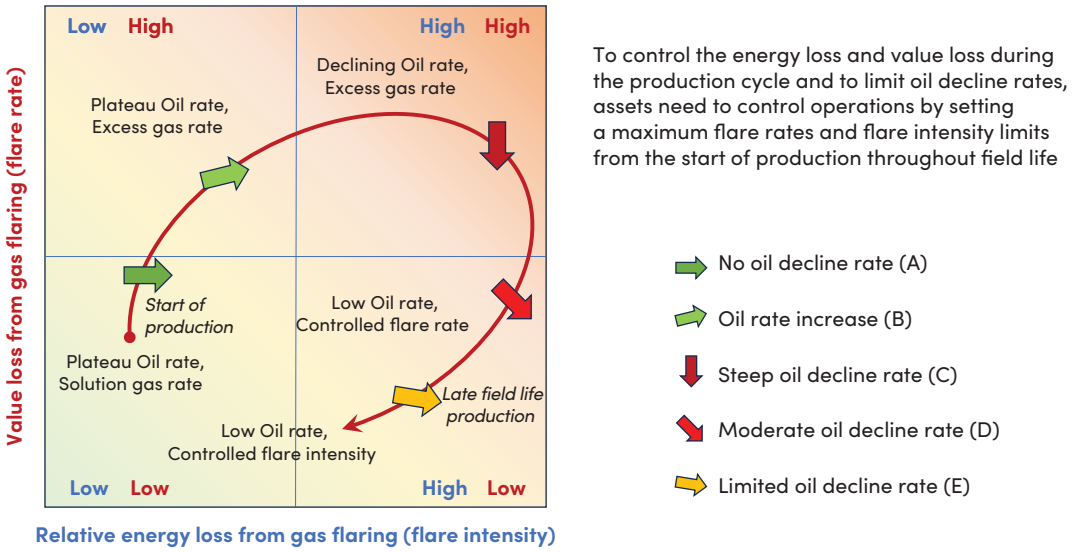


Note: Author's illustration, flare data from VIIRS.

The above analysis (Figures 6 and 7a) of value loss and percentage energy loss indicates an observed flaring life cycle that coincides with specific oil production phases (see Figure 9).

- Production generally starts with low gas rates and high oil rates from the reservoir that is at initial pressure conditions. Hence flare value and energy loss are low (A).
- Flaring may rise rapidly when oil rates are at plateau and gas breakthrough is observed. The increase in associated gas may increase oil well production rates if these are lift-constrained. Produced (excess) gas that is not reinjected but flared will cause a high value loss. Due to the high oil rates, the relative energy loss is low but flared value loss is high (B).
- As reservoir energy depletes at the producing wells, oil rates start to decline while flaring remains high (high value loss and increasingly high relative energy loss), (C).
- The oil decline rate correlates with the flaring intensity (C to E).
- Reservoir energy losses and production process instabilities require control of flare rates to stabilize the declines in oil production (D).
- When the reservoir becomes increasingly mature in the production life cycle, flaring control should shift from flare rate to flare intensity. Flare process control reduces flare value loss and relative energy loss (E).
- Although flare rates can be reduced below early production flaring, energy loss generally will increase in late life as flare intensity rises (E).

FIGURE 9. Gas flaring linked to oil production life cycle



Notes: Author's illustration. A stringent regulatory definition of routine flaring combined with concurrent limits on flaring rates and intensities constrict the flaring envelope, thereby minimizing cumulative operational losses.

Not all reservoirs react similarly to the loss of associated gas. In case of strong aquifer drive or a water injection development scheme, the reservoir energy can be supported by alternative energy than coming from solution gas (reinjection).

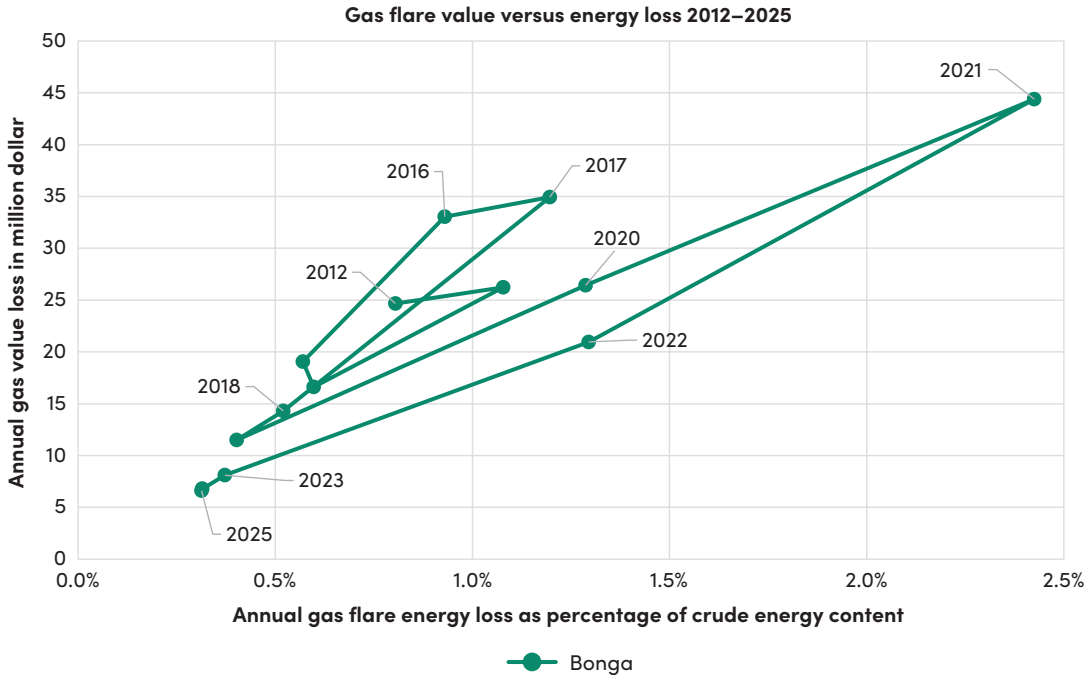
To manage the extent of value loss from excessive gas flaring (i.e. natural gas wasted and the rate of oil decline), it is important to set proactively two gas flare constraints:

- A maximum gas flare rate limit to control the gas resource loss.
- A maximum gas flare intensity limit to control the rate of oil decline.

These limits need to be set at the start of production before excess gas is produced as too late implementation (after gas breakthrough in the production) is likely to cause a prolonged period of oil decline and possible loss of oil ultimate recovery.

Figure 10 shows Bonga's relatively well-managed gas flaring envelope. It compares well with the other assets evaluated (as shown in Figure 6). Though to a lesser degree than in other cases, average gas flare rates rose from April 2016 onwards and production started to decline a few months later in August, after which gas intensity gas was brought under control to below 5 m^3/m^3 by 2018. Exceptional to the asset's generally good performance, gas export equipment failures between 2020 and 2022 resulted in substantial surplus flaring.

FIGURE 10. Gas flare energy and value loss trends for Bonga

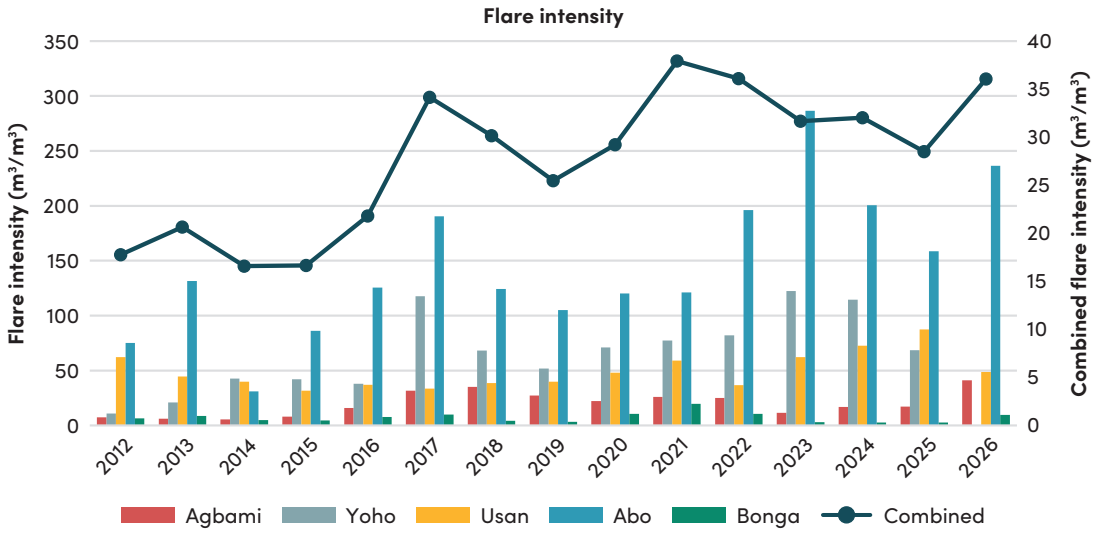


Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/. Energy loss (%) = energy intensity (m^3/m^3) × 0.1225.

5. Gas flaring intensity and variability measures

Processing and data analytics of flare rates allow meaningful observations to be made. Several flare characteristics provide insight into flare operations, such as the previously described flare intensity. This measure describes the relationship between flare rates and oil production rates and is defined as the volume flared divided by the oil volume produced (m^3/m^3). A high flare intensity implies much gas flared per volume of oil produced. This production efficiency measure is a key variable to calculate the energy loss from flaring as percentage of crude oil energy content produced (see previous section). Flare intensity is also related to routine flaring and oil production decline as shown in the next sections. Finally, flare intensity is used to benchmark assets on their flaring performance, as described in the OPM report.[15] Figure 11 shows the flaring intensity of the offshore assets, extended for the 2023 to 2026 year-to-date period.[16] In recent years, the high flaring intensity assets (Abo, Yoho, Usan) further increased their flaring intensities, while low flaring intensity assets (Bonga, Agbami) decreased their flaring intensities compared to the OPM study analysis period (2012–2022).

FIGURE 11. Flare intensity for the five offshore assets and combined trend (2012–June 2026)



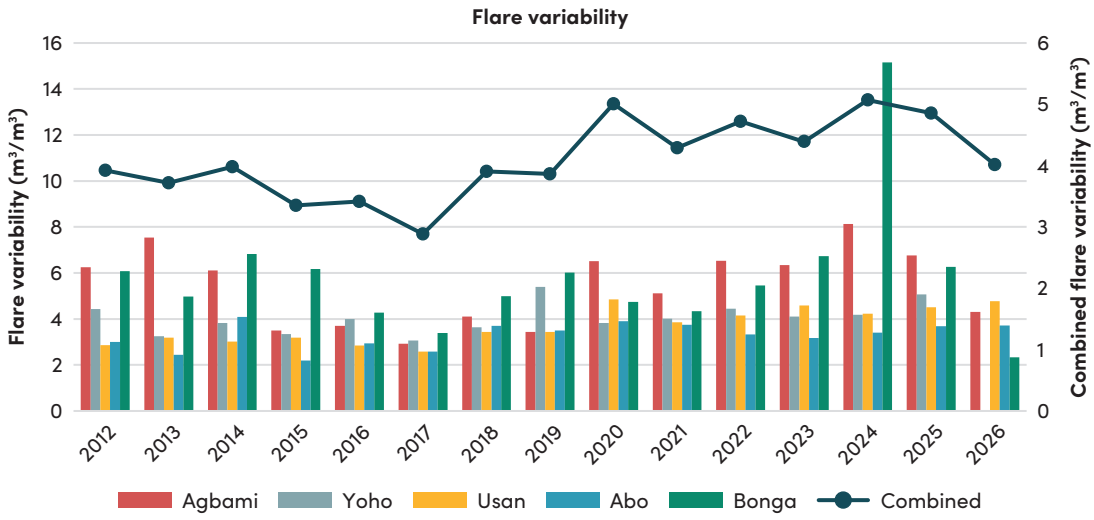
Note: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/.

For the combined five offshore assets, the combined flare intensity has been decreasing in the 2022–2025 period, as Bonga and Agbami oil production provide more weight to the averaging of flare intensities. The current year 2026 will be interesting as annualized year-to-date flare intensities for Agbami are the highest ever and for Bonga second highest.

15 Section 4, https://www.opml.co.uk/sites/default/files/2024-02/nigeria-super-emitters-offshore-finalv3.pdf.
16 Flare intensity is strongly influenced by seasonality and this may influence 2026 year-to-date data.

Flare variability is defined as the maximum observed flare rate in a month divided by the monthly average flare rate. The flare variability performance for the five individual five assets is presented in Figure 12. Of the five assets evaluated, Bonga has overtaken Agbami as the asset with overall highest flare variability, and Abo remains the lowest. **Flare variability is indicative for the severity and frequency of short duration production upsets**. Therefore, this measure is particularly sensitive to identify process trips and reactive emergency shutdowns, that are related to overall topsides process stability. **Longer duration failures and assets that are not repaired (such as e.g. flash gas compressors) show as continuous (i.e. 'routine') flaring and are identified by flare intensity**. The lowest flare variability value of 1 indicates a constant flare rate throughout the month. Bonga's high flare variability has to be seen in context of its overall low flare rate, indicating production process trips dominate any flaring and that routine flaring is therefore low.

FIGURE 12. Flare variability for the five offshore assets and combined trend (2012–June 2026)



Note: Author's illustration, flare data from VIIRS.

6. Assessment of routine flaring in super-emitter operations

Section 1 explained that gas flaring can have multiple causes. In this study we differentiate incidental safety (non-routine) flaring to shut-in production for operational reasons from continuous routine flaring to sustain production. Routine flaring occurs when gas process equipment cannot handle the gas volumes produced to reinject gas or export it (in the case of Bonga). Routine flaring can occur when gas compression equipment fails, gas reinjection wells cannot handle the produced

gas rates, gas injection or export risers are derated,[17] or when there are various other process-related constraints. In such situations, it would be prudent to reduce production rates to not exceed process equipment limitations. However, as equipment upgrades or repairs may take time to be implemented, it appears common practice for the assets studied that oil production is allowed to continue while excess gas is flared.

The OPM report raised the following concerns regarding routine flaring

> *'If a company is facing equipment outages, such as flash gas compressor failure, but continues to produce and therefore flare excess gas, is this considered 'routine' or 'non-routine' flaring? What if such company now decides that repairing the flash gas compressor is too expensive and continues to flare gas, at what point does the flaring become routine? If a company has made investment to reinject its produced gas, but faces a problem to dispose of all the gas due to lack of well injectivity, compression capacity or reservoir performance, does this qualify as 'routine' or 'non-routine' flaring?*
>
> *Shell's 2021 Sustainability Report, provides answers to above questions: "All of Shell's operated assets within the Integrated Gas business already comply with zero routine flaring, as they were designed to gather gas resources to sell and avoid routine flaring."*
>
> *This implies that as long as assets were designed to avoid flaring, any flaring by these assets is considered non-routine flaring, even if the flaring is done voluntary rather than for safety reasons. Following the same logic, the voluntary flaring at Bonga in 2021 due to delayed repairs is considered non-routine, even though this is a clear case of 'flaring to produce'. With companies' publicized commitments to stop routine flaring there is a risk that these companies use loopholes to requalify routine flaring into non-routine flaring. Stringent flaring definitions and verification processes are recommended.'*[18]

Recent progress updates on the World Bank Zero Routine Flaring by 2030 initiative highlights the importance of utilizing consistent flaring definitions that address all non-safety related flaring. The Clean Air Task Force states in the 2024 Flaring Accountability report:

> *'The level of ambition must be raised to eliminate virtually all flaring at oil and gas assets around the world—**both routine and non-routine**—that is not legitimately emergency-related. A focus **only on "Zero Routine Flaring" is no longer sufficient**.*

17 To derate means to intentionally lower the maximum operating limit, capacity, or power rating of a piece of equipment, machine, or system. This is done to protect the equipment and extend its operational lifespan, especially when running under harsh or non-ideal conditions.

18 Section 5.2 – Box A, https://www.opml.co.uk/sites/default/files/2024-02/nigeria-super-emitters-offshore-finalv3.pdf.

> *The 10 IOCs have committed to ending "routine flaring" by 2030 as part of the World Bank's ZRF Initiative, but only 30% of total reported flaring from these companies was listed as "routine" in 2022. Thus, if these IOCs only meet their target to eliminate "routine flaring," the other 70% of flaring classified as "non-routine" may remain largely unabated. In this scenario, flaring will remain far higher than the levels required under the IEA's net zero target (a 95% reduction by 2030)."*[19]

Hence, a transparent methodology is needed that can be applied to gas flaring data to distinguish routine flaring from non-routine flaring. The criteria for the routine flaring metric have been defined as:

- to be transparent, easy to understand and implement;
- applicable for all types of assets and flaring performance trends (large, small, intermittent, continuous flares);
- applicable for continuous (metered) flare data as well as sparse (satellite) flare observations;
- to be consistent in distinguishing routine from non-routine flaring without the need for additional operational data or insight;
- to provide a logical distinction between routine flaring and other (non-routine) flaring.

The approach that has been applied for this study defines the monthly contribution to non-routine flaring as the volume of flared gas that exceeds the average flare rate for that month. Routine flaring is therefore the complementary part to non-routine flaring:

$$\text{Routine flaring (RF)} = \text{total flaring (TF)} - \text{non-routine flaring (NRF)} \tag{1}$$

$$\text{NRF} = \sum_{i=1}^{N} \max(TF(i) - \overline{TF}, 0) \tag{2}$$

$$\text{with } \overline{TF} = \frac{1}{N}\sum_{i=1}^{N} TF(i) \qquad \wedge N > 0, \text{otherwise } 0 \tag{3}$$

and N is number of days with flare observations per month[20]

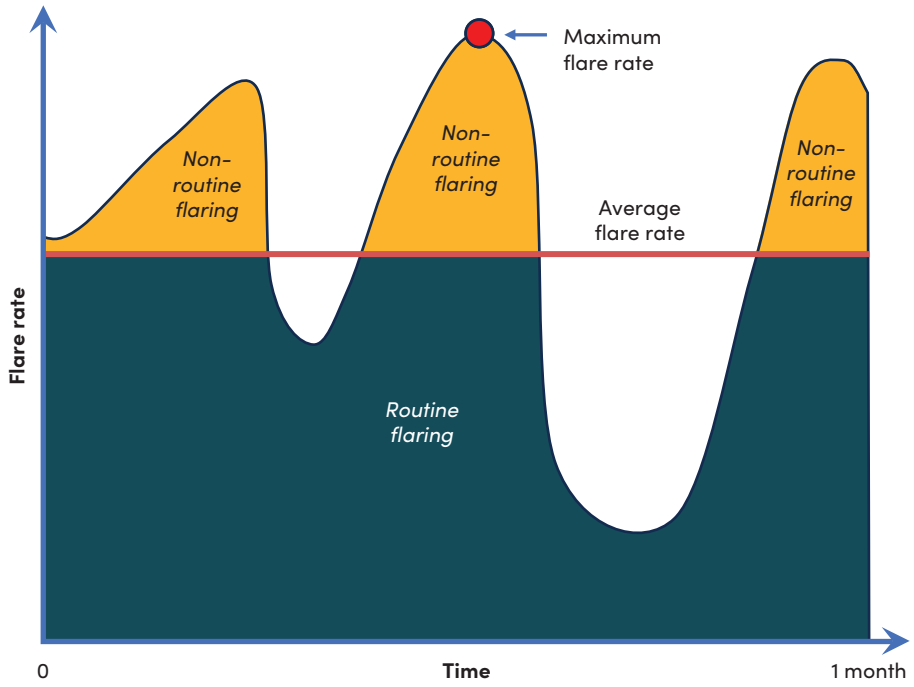
$$\text{RF percentage} = \frac{\sum_{i=1}^{N} TF(i) - \sum_{i=1}^{N} \max(TF(i) - \overline{TF}, 0)}{\sum_{i=1}^{N} TF(i)} \qquad \wedge \overline{TF} > 0, \text{otherwise } 0 \tag{4}$$

19 Clean Air Task Force, "Flaring Accountability – Global gas flaring by major oil and gas companies and their partners", 12 November 2024; https://www.catf.us/resource/flaring-accountability/.

20 Days with missing flare observations, for example if cloudy weather prevents readings, are excluded from the averaging process. Hence, N can be less than the number of days in a month. A zero-flare observation (i.e the flare is confirmed to be off) is counted as zero flare rate and included in the number of flare observations.

Consider the hypothetical cases of two flares, each with a total monthly flare rate of 30 million m^3. In the first case the flare is observed every day at a constant 1 million m^3/day, while the other flare is lit only for one day and flares the total 30 million m^3 on that single day. For the first flare, the routine flaring percentage is 100%, while for the second it is 3.3%.[21] The application of the routine flaring metric is illustrated in the schematic in Figure 13, while Figure 14 shows the methodology applied to the Bonga asset.

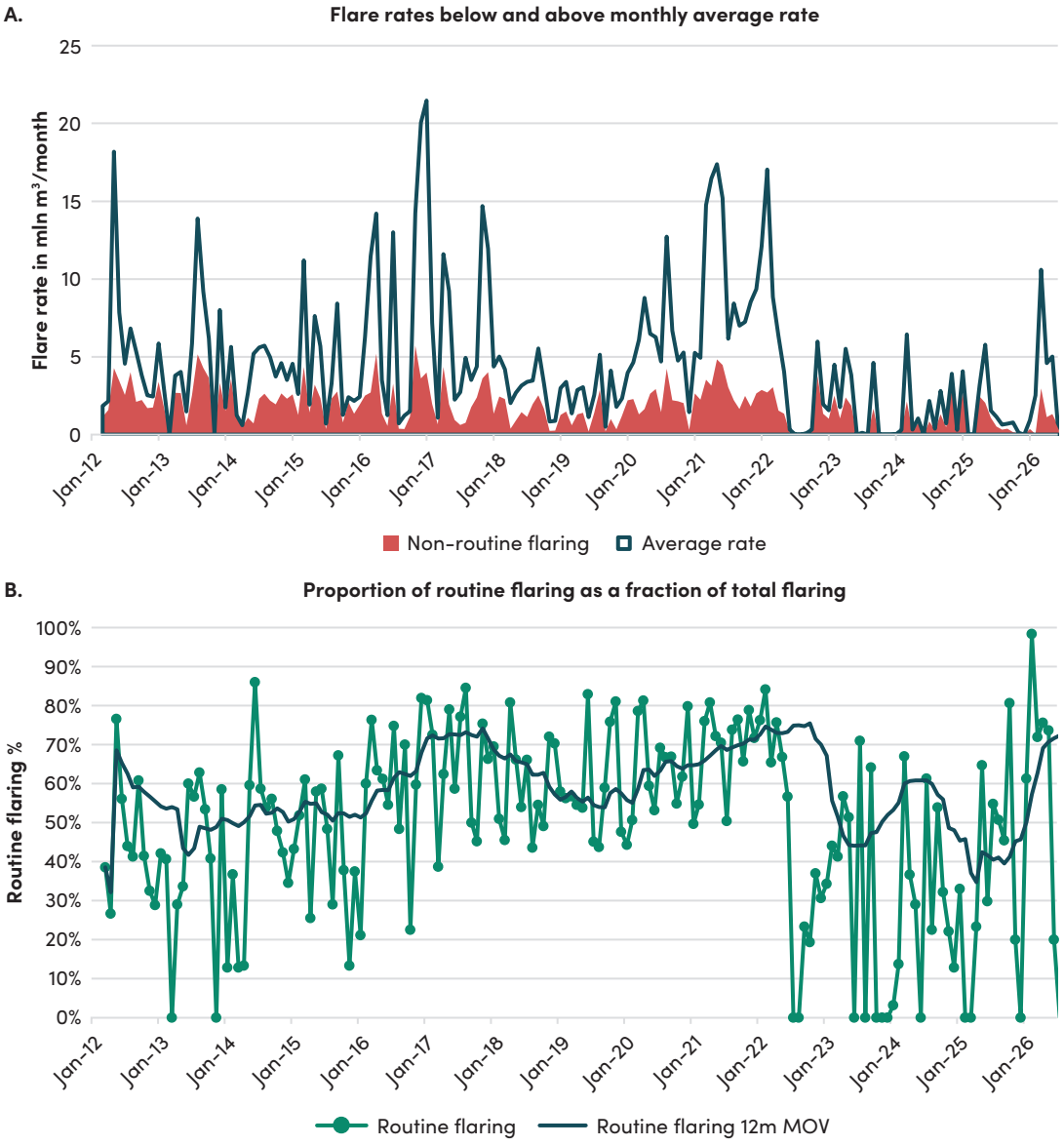
FIGURE 13. Schematic of method for determining routine flaring versus non-routine flaring



Notes: Author's illustration. In case of continuous (metered) flare data the contributions of routine and non-routine areas are determined by the depicted teal and gold areas in the graph. In case of discrete (satellite) flare data, this is approximated by the sum of daily observations as shown by formulas (2) to (5).

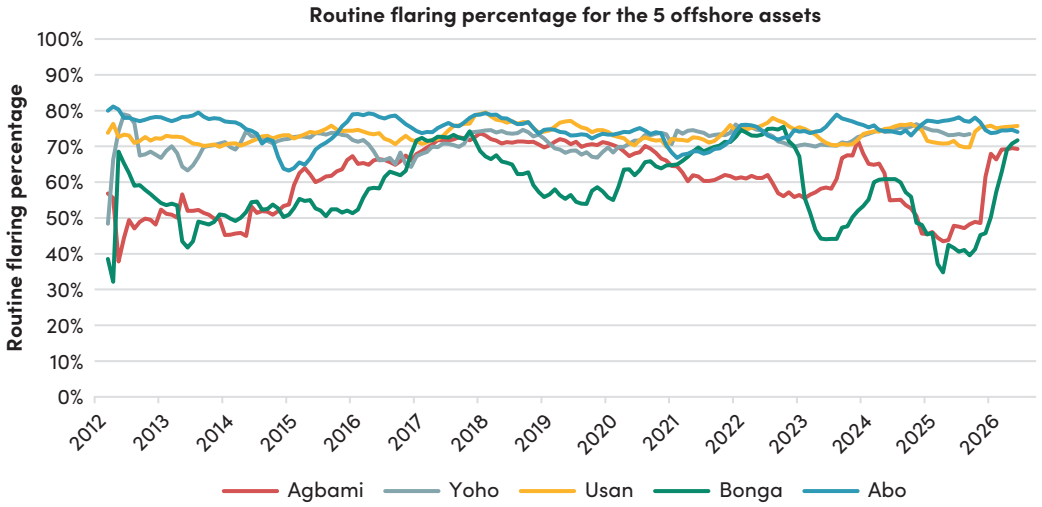
21 The objective of this routine flaring definition is to provide a simple, robust, and intuitive calculation method, even if it may not give precise outcome of 0% routine flaring for a single flaring event per month.

FIGURE 14. Routine flaring assessment method applied to Bonga



Notes: Author's illustration, flare data from VIIRS. In graph a (top) the red area depicts monthly assessments of non-routine flaring **volume** compared to total flaring (teal curve). In graph b (bottom) the routine flaring **percentage** as a fraction of total flaring is shown for each month (green curve). The teal curve shows the routine flaring trend as the 12-month trailing moving average (12m MOV) of monthly routine flaring percentage.

FIGURE 15. Routine flaring contribution to total flaring



Notes: Author's illustration, flare data from VIIRS. The routine flaring curves show the routine flaring trend as the 12-month trailing moving average of monthly routine flaring percentage.

The methodology presented here is a refinement to the method used to determine routine flaring in the OPM study using a similar approach but based on monthly average flare rates below the 6-month trailing moving average gas flare rates.

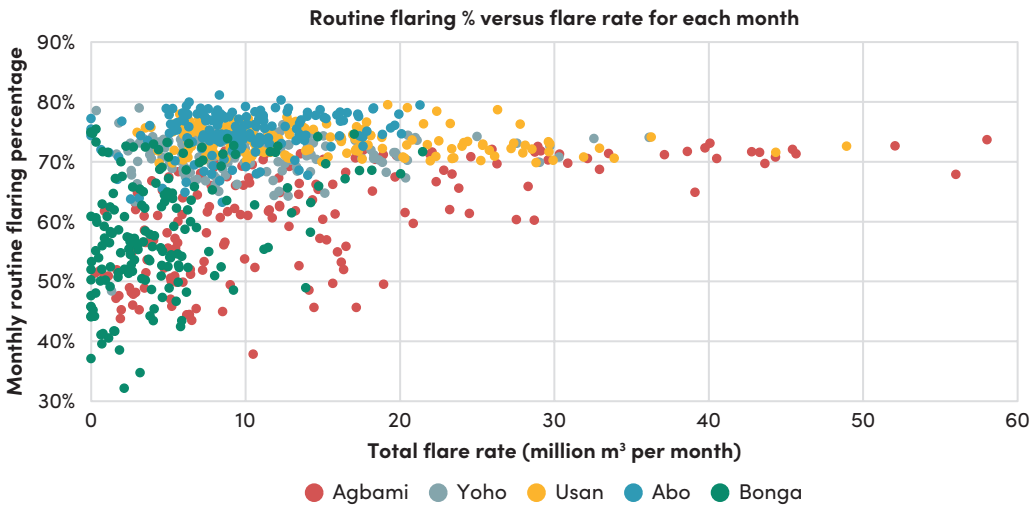
In the analysis, Bonga is showing a lower percentage of routine flaring than the other four assets. This is partially due to having access to gas export that the other facilities do not have. However, when Bonga's gas export was constrained due to technical problems (2021–2022), routine flaring percentage reached similar levels to those of the other four assets.

The field life average routine flare percentages for the five assets ranked from low to high are: Bonga (59%), Agbami (62%), Yoho (71%), Usan (74%), Abo (75%).

In addition to the routine flaring percentage, also the total flaring rates are relevant in assessing the impact of routine flaring. Non-routine flaring shows high daily rates, but is intermittent, while routine flaring is more continuous. Hence, when flare rates are high over longer periods, this is more likely to be caused by routine flaring than non-routine flaring. This is illustrated by the cross plot in Figure 16.

Comparing operational performance by assessing routine flaring between assets, it is recommended to do this at specific flare rates. For example, for flare rates up to 5 million m^3 per month, the average routine flaring percentages for each of the five assets are: Bonga (56%), Agbami (54%), Yoho (55%), Usan (74%), Abo (75%).

FIGURE 16. Cross plot of routine flaring percentage versus total flare rate (by month)



Notes: Author's illustration, flare data from VIIRS. Each point represents one monthly assessment of total flare rate and routine flaring percentage.

7. Oil decline and flaring intensity

Gas flaring occurs most commonly when associated gas is produced when recovering oil. Detailed gas flaring analysis reveals that excessive gas flaring correlates with oil production decline rates. The principles for these reservoir production mechanisms have been described in Box A.

Flare intensity is the measure used in this study to assess the relationship between flaring of excess produced gas and oil decline over longer time periods.[22] Flare intensities are measured based on monthly average flare and oil rates, but may be further averaged based on 3-month or 12-month moving averages (MA) in case highly variable process conditions mask long-term trends. Oil declines are determined on an annual basis,

$$D = -\frac{R(t) - R(t - 1\,year)}{R(t - 1\,year)} \tag{5}$$

with D = annual oil decline rate

$R(t)$ = oil production rate at time t

Figure 9 visualizes the concept of oil decline during the oil field development life cycle and the relationship with gas flaring. Flare intensity is directly related to the relative energy loss from flaring when producing oil.

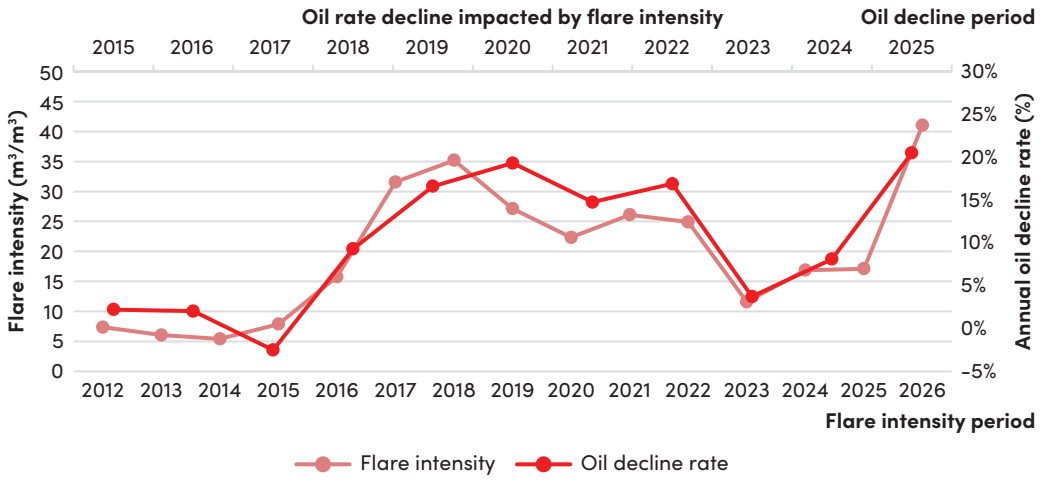
22 In case of overproduced reservoirs, acceleration of oil production is more than offset by disproportionately steeper oil decline rates, resulting in compromised oil ultimate recovery, and hence value loss, for the field.

The observation that gas flaring could be related to oil decline rates is important because assessments of value loss from gas flaring generally consider only the impact from the gas being burned without considering the lost oil value impact. For most oil developments, the value of the oil produced much outweighs the value of the gas wasted (see Table 1, Figure 6). However, if the oil value is also impacted due to the quality of operations, for which gas flaring is an indicator, the significance of flare monitoring increases further.

The relationship between gas flaring and oil decline is complex. There is a degree of causality in producing and flaring excess gas from the reservoir that reduces reservoir energy and thus causes a decline in well productivity (Box A). Oil temporarily declines during major shutdowns when flaring is also high, contributing to the positive correlation between gas flaring and oil decline. The causality between oil decline and flare intensity also can occur in reverse: when operators set a maximum flare rate for their operations and oil production declines, flare intensity increases accordingly. There are also indirect relationships between gas flaring and oil rate declines, when gas flaring is seen as a measure of poor quality of operations. Operators that flare significantly are likely to be equally poor in optimizing other (oil production) related aspects of their oil field operations. In the early production phase, oil rates may be constrained by other factors than reservoir deliverability and hence oil decline impacts may be observed with a time delay, while more mature reservoirs tend to respond more dynamically (i.e. immediately) to production imbalances. Despite the complexities and variety in mechanics that link gas flaring to oil decline rates, most of the assets investigated show this relationship more or less clearly.

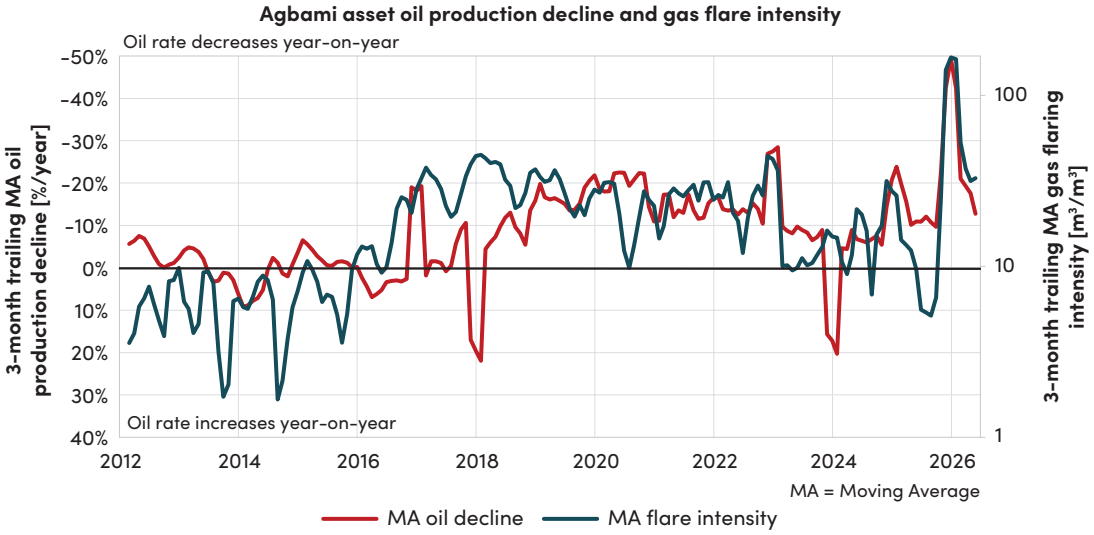
The relationship between flare intensity and oil decline rates is illustrated by Agbami's performance in Figure 17 (based on annual average data) and Figure 18 (based on higher frequency 3-month Trailing Moving Average, TMA, data). Agbami was process constrained until early 2018 when oil production came off plateau and the match between flare intensity and oil decline became more clearly defined. When flare intensities are averaged over longer time period (12-month TMA), the 2-year lag in oil decline in the earlier years and the overall trend is more clearly shown (Figure 19).

FIGURE 17. Agbami asset oil decline and flare intensity (annual averages)



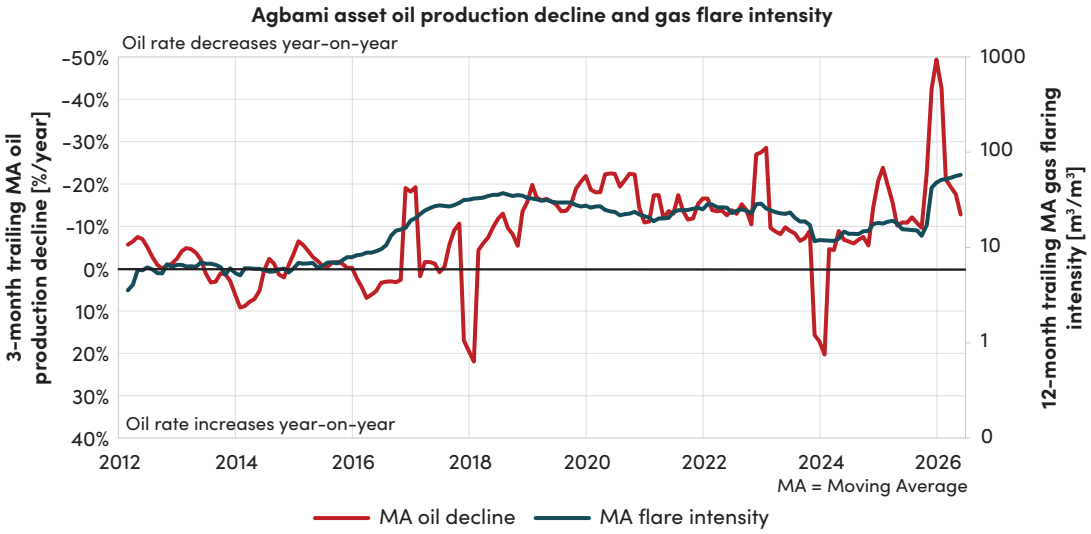
Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/. During the earlier years, flare intensity precedes oil decline by two years, while in subsequent years flare intensity and oil decline are coincidental.

FIGURE 18. Agbami asset oil decline and flare intensity (3-month trailing moving averages)



Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/. Note the two orders in magnitude in flare intensity variations and hence the use of a logarithmic axis (right).

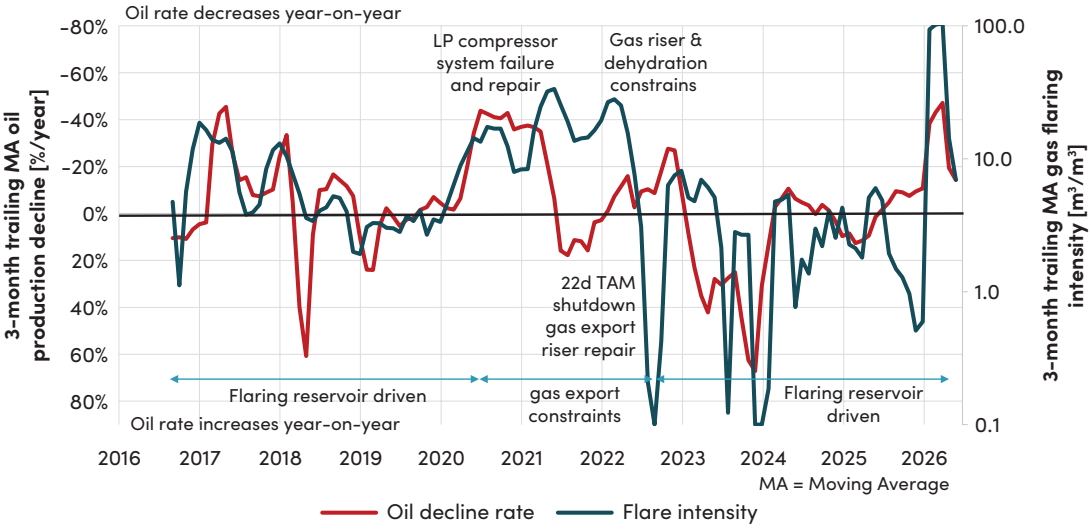
FIGURE 19. Agbami asset (3-month TMA) oil decline and (12-month TMA) flare intensity



Note: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/.

Similar correlations between flare intensity and oil decline are shown by the other assets analyzed, see the example for Bonga in Figure 20.

FIGURE 20. Bonga asset oil decline and flare intensity (3-month TMA)



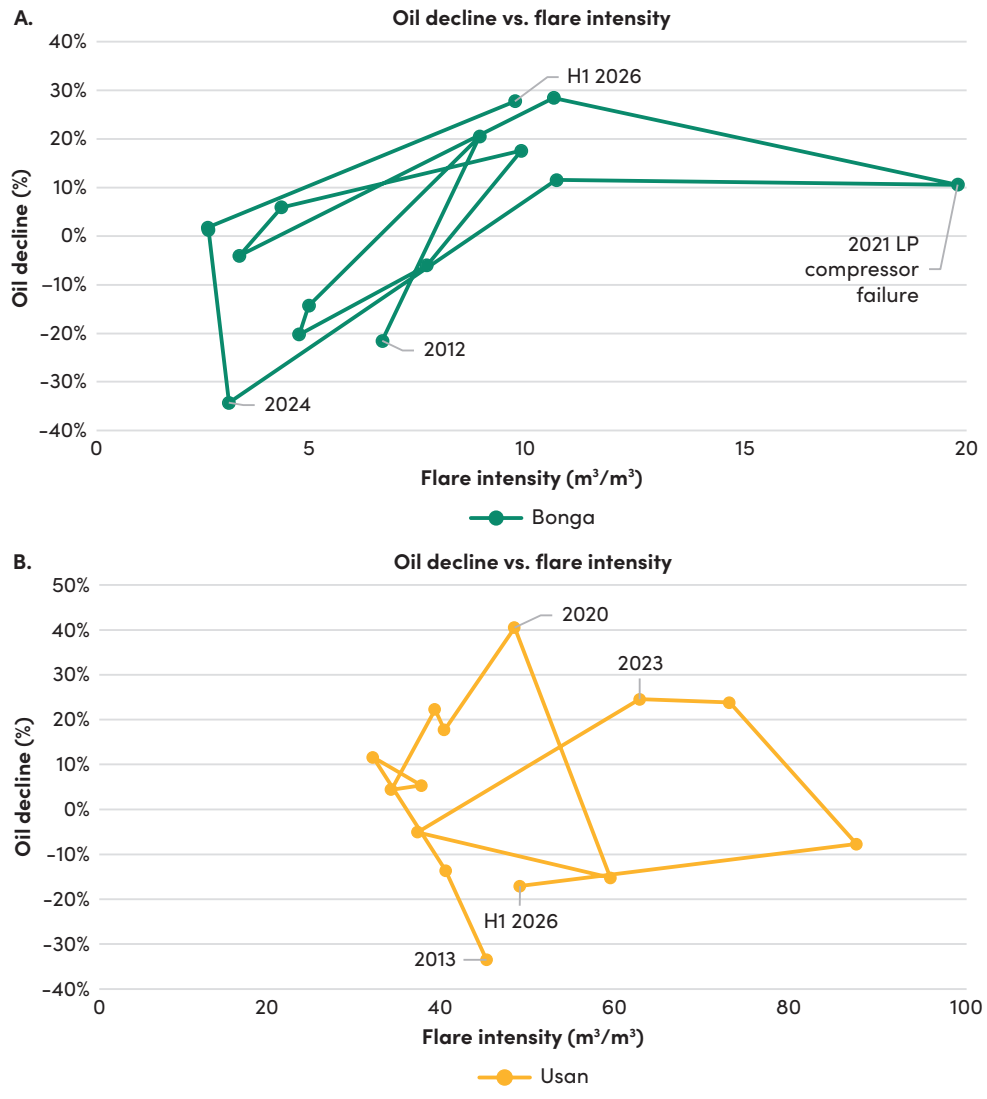
Note: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/.

Bonga's flaring performance in 2021 and 2022 was driven by gas export constraints instead of reservoir issues. This is reflected in the red and teal curves breaking their overall trending for these years, but catching up again from 2023 onwards. There are many factors that affect oil rates

and flaring intensity and hence a perfect association between these two parameters should not be expected. Nonetheless, comparing the different assets, flaring intensity is shown to be a useful metric for determining quality of operations. In Figure 21, a comparison is made between the asset with lowest flare rate and highest flare rate reduction (Bonga, top) and the asset with current highest flare rate and highest flare rate increase (Usan, bottom).

With the exception of the period of LP compressor failure in 2021, Bonga's performance curve shows low flare intensities that are consistently within a narrow range (below 10 m^3/m^3). In contrast, Usan flare intensities show a much wider operational envelope that are a factor 20 to 34 higher (during 2023–2025) and exhibit a trend over time towards higher values (see also Figure 11).

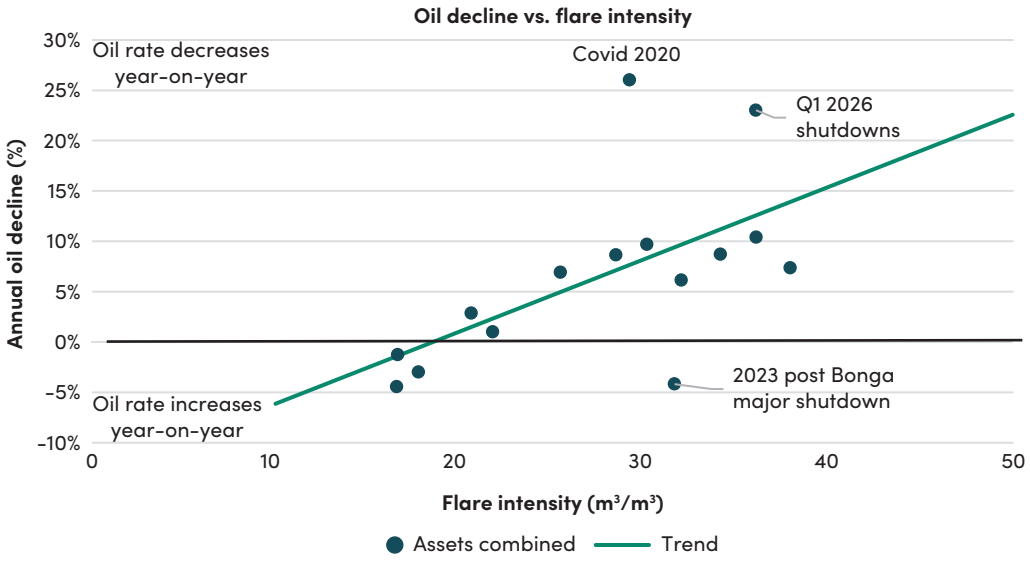
FIGURE 21. Bonga (top) and Usan (bottom) asset oil decline and flare intensity (3-month TMA)



Note: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/.

To assess commonality in the relationship between flare intensity and oil decline, the performance of all five assets in terms of flare and oil production rates was combined to calculate flare intensity and oil decline for the portfolio as a whole. Figure 22 shows a cross plot of the results with each point representing a performance year.

FIGURE 22. Oil decline rate versus flare intensity by year for the portfolio of five offshore assets



Note: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/.

There are three points that show a larger deviation in trend. The first is 2020, when global crude oversupply and Covid caused OPEC to impose stringent production quota for countries, including Nigeria. Hence, the large production decline for that year did not result from operational or reservoir performance issues, but was due to political measures. A second point of deviation was 2023, when Bonga was fully onstream after the prolonged 2022 shutdown for gas export riser repairs.[23] The early months in 2026 is when traditionally maintenance activities take place, resulting in a combination of higher oil rate declines and higher flaring as indicated by Figure 22. It is expected that the latter period of 2026 will result in higher oil production and lower flare rates that will balance out the average 2026 production performance. The correlation coefficient between flaring intensity and oil decline is 0.64 including all data (for Bonga asset itself the correlation is 0.69).

The relationship between gas flaring and oil decline is complex and each asset has its own specific relationship between oil decline and flare intensity. Figure 22 shows that for all five assets combined,

23 In 2023, Bonga oil rate represented 43% of the combined production rate of the five offshore assets. In October 2022, the facility was shut down for the repair of the export riser and opportunity was taken to execute scheduled maintenance in the same time window. This resulted in 2023 to be a year of high oil throughput for Bonga as no maintenance shutdown was required for that year.

annual average flare intensities below 19 m^3 of gas flared per m^3 of oil produced do not exhibit incremental oil decline, while at 30 m^3/m^3 the annual oil decline is 8.2%. Throughout the 2020–2025 period, the annual aggregate flaring intensity across the five assets ranged between 28.5 and 37.9 m^3/m^3. Despite potential multi-causality in the flare intensity-oil decline relationship, the financial stakes are profound.

In 2025 the accelerated oil production decline from higher flaring intensity for these assets was 8.6%, exceeding an average field decline of 5%. The estimated oil value loss due to the additional 3.6% decline is USD 217 million (at USD 60/bbl oil price). The value of such oil decline losses would be incremental to the flare volume losses assessed.

8. Flaring performance review by asset

An initial analysis has been conducted to update the flaring performance for the five Nigeria offshore super-emitter flares documented in the OPM report, published in 2023, based on VIIRS satellite flaring data ranging 2012–2022.[24]

Since the OPM report, three more years of satellite data have become available, courtesy of the Earth Observation Group, Payne Institute for Public Policy.[25,26,27] The current supplementary analysis shows noteworthy developments for each of these five super-emitters, with mixed outcomes. Under the NNPC Gas Master Plan 2026 released in January, the government and operators are committed to ending routine gas flaring by 2027, three years earlier than The World Bank Zero Routine Flaring by 2030 initiative. This is a good time to take stock if the super-emitters are on track for delivery of lower flaring emissions.

- **Agbami:** Flare rates of this Chevron operated asset decreased from 172.5 million m^3/yr (2020–2022) to 74.9 million m^3/yr (2023–2025), **a decrease of 57%**. However, in the last six months, flaring increased again to 185.6 million m^3/yr on an annualized basis. This increase could be due to construction activities for the ongoing Agbami Gas Project. This project aims to eliminate routine flaring, improve flare quality and provide compression redundancy and reliability for potential future gas export of up to 150 MMscf/d to existing offshore gas gathering networks.
- **Yoho:** Exxon sold the asset to Seplat Energy which took operatorship in December 2024. In the two years leading up to the sale, flaring increased from 120.3 million m^3/yr to

24 https://energycc.com/news/energycc-major-studies-on-nigeria-super-emitters-published-by-oxford-policy-management.html.

25 Zhizhin, M.; Matveev, A.; Ghosh, T.; Hsu, F.-C.; Howells, M.; Elvidge, C. Measuring Gas Flaring in Russia with Multispectral VIIRS Nightfire. Remote Sens. 2021, 13, 3078. https://doi.org/10.3390/rs13163078.

26 Elvidge, C.D.; Zhizhin, M.; Baugh, K.; Hsu, F.-C.; Ghosh, T. Methods for Global Survey of Natural Gas Flaring from Visible Infrared Imaging Radiometer Suite Data. Energies 2016, 9, 14. https://doi.org/10.3390/en9010014.

27 Elvidge, C.D.; Zhizhin, M.; Hsu, F.-C.; Baugh, K.E. VIIRS Nightfire: Satellite Pyrometry at Night. Remote Sens. 2013, 5, 4423–4449. https://doi.org/10.3390/rs5094423.

187.7 million m^3/yr, **an increase of 56%**. After Seplat took over the asset, flare rates declined to 103.7 million m^3/yr on an annualized basis, **a decrease of 45%** compared to 2023–2024 (and **15%** compared to 2020–2022). It is a common for flaring to increase before an asset sale as a result of overproduction of the reservoir to support the sale (price). Unfortunately, Yoho FPSO suffered a fire on 27 September 2025 and the asset remains closed in since for repairs and upgrades.

- **Usan:** In the last three years, Exxon delivered a business-as-usual performance in Usan, with the production getting more mature (increased flare rate variability) and flare rates increasing from 115.3 million m^3/yr (2020–2022) to 124.4 million m^3/yr (2023–2025), **an increase of 8%**. During 2025–2027, Exxon is investing USD 1.5 billion into revitalizing the Usan asset to address its production decline. Most of the work is focused on infill drilling activities and subsea infrastructure. Additional gas injection wells aim to eliminate routine flaring. Usan FPSO is positioned as a regional processing hub for gas handling and export to NLNG assets or the domestic market, aligning with the federal government's gas-to-power initiatives.
- **Abo:** ENI executed a major shutdown of Abo FPSO in 2023 to improve HSE and operational performance 'even to the detriment of production'. The shutdown included a third compressor to have redundancy and reduce flaring. In the 2023 review, prior to the shutdown, it was concluded that Abo's flaring is predominantly due to long term unavailability or impairment of its gas compression and/or gas reinjection facilities. Together with Usan, Abo had the highest degree of routine flaring (74%) among the five super-emitters. However, after the process upgrades were installed, significant flare reductions appear not to have materialized. VNF flare rates decreased from 127.1 million m^3/yr (2020–2022) to 119.1 million m^3/yr (2023–2025), **a decrease of 6%**. Neither flare quality nor flare variability changed in these periods before and after the 2023 shutdown.
- **Bonga:** Shell appears to have delivered on its promise to reduce flaring from a combination of measures, including improvements on its low-pressure gas compression system (2021/2022), improved operational efficiency through resolving asset integrity issues, and the execution of a pilot flare elimination project. Average annual flare rates declined from 83.1 million m^3/yr during 2020–2022 to 19.5 million m^3/yr during 2023–2025, **a reduction of 77%**. The asset shows a marked reduction in non-zero flare rate observations from 517 to 60, in addition to lower rates. Zero rate flare observations more than doubled from 47 to 112.

The flare performance review shows a mixed outcome among the five offshore super-emitter flares. Shell's Bonga shows the clearest results of flare reductions from implementing asset improvements. Yoho showed initial positive results in flare reductions from Seplat Energy taking over operatorship from Exxon, but the evaluation period was curtailed due to an asset fire. Agbami (Chevron) decreased flaring significantly and the Agbami Gas Project ongoing offers potential for further flare reductions after completion. Usan (Exxon) and Abo (ENI) flaring increased during the last three years, compared to the period prior.

It is positive that four of the five assets received significant investments to upgrade their (emissions) performance. In addition to Bonga, also Yoho, Agbami, and Usan assets are investing in potential future gas monetization through FLNG and gas export to existing offshore gas gathering networks. The Nigerian government's efforts to resolve disputes with the energy majors, enhance its offshore regulatory and fiscal frameworks, and provide license extensions, have all contributed to unlock these investments and secure immediate operational improvements. For four of the five assets, projects are currently ongoing to secure a long-term future with new fields coming on stream, gas export schemes and lower flaring emissions.

The NLNG facility appears to have low utilization since 2021, as low as 58% in 2023 and 66% in 2025.[28] With increased global importance of energy security and increasing LNG prices,[29] monetizing more of Nigeria's gas (instead of flaring) makes much sense. The upcoming hybrid expansion of NLNG with Train 7 (+4.2 mtpa) and debottlenecking of the existing 6 trains (+3.4 to 3.8 mtpa) will boost the plant's capacity from 22 mtpa to 30 mtpa.[30] The combination of low (66%) current utilization and 36% additional liquefaction capacity provides significant ullage (47.75 million m^3/d)[31] in the NLNG facility to monetize existing flare gas and develop new oil and gas resources. Increased focus on gas conservation and capturing produced gas for NLNG export and for domestic needs are central to improving Nigeria's fiscal revenues and obtaining adequate return on investment for Nigeria's oil and gas sector.

8.1 Agbami

Agbami FPSO is Chevron's largest producing asset in Nigeria and has produced more than 1 billion barrels of oil to date. Operated under a zero routine flaring production policy, produced natural gas is to be fully reinjected to optimize oil recovery and for gas conservation. The Agbami gas injector wells were primarily drilled and completed between 2007 and 2015 across Chevron's initial three-phase field development plan. The asset employs a "crestal gas injection" strategy to maintain reservoir pressure and prevent flaring. FPSO topsides gas injection capacity installed was 415 MMscf/d gas. No physical, rig-based downhole well interventions were conducted to address injectivity on the Agbami gas injector wells. Instead, Chevron avoided costly physical interventions by managing and improving gas injectivity remotely using built-in Intelligent Well Completions (IWCs).

A flare ranking analysis 2017–2021 detailed in the 2023 OPM report, identified Agbami as Nigeria's largest flare, ranked 39th globally. In 2024, it had declined to become Nigeria's 15th largest flare and

28 IGU World LNG Report 2026 and 2024, https://www.igu.org/igu-reports/2026-world-lng-report, and https://www.igu.org/igu-reports/2024-world-lng-report.

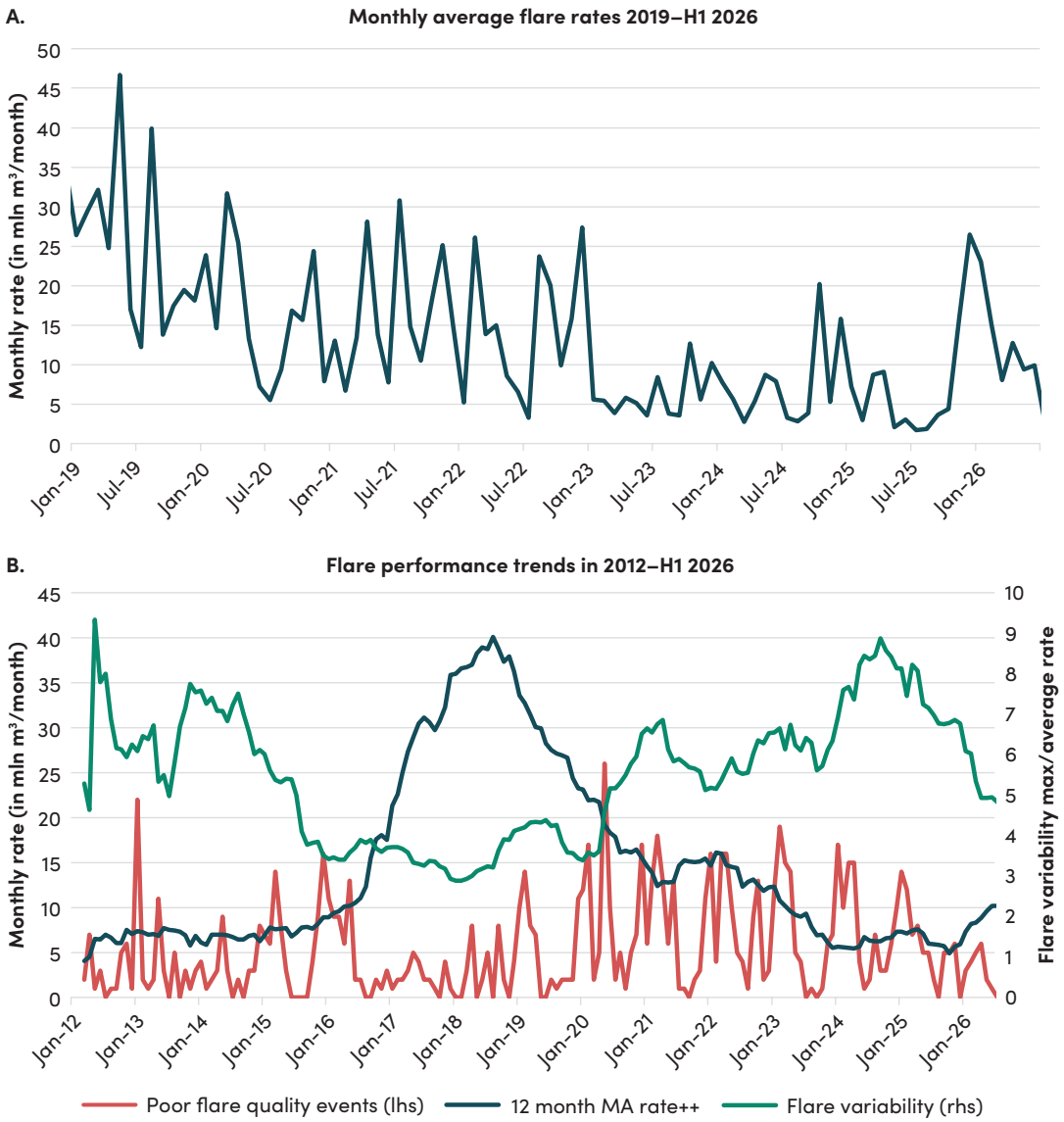
29 IEA reported LNG pricing for 2025 that averaged USD 12/MMBTU in Europe (TTF) and Asia (JKM) markets; https://www.iea.org/reports/gas-market-report-q1-2026/executive-summary.

30 Details on NLNG capacity upgrades with Train 7 expansion; https://www.gem.wiki/Nigeria_LNG_Terminal.

31 1 mtpa of upstream gas with density 0.888 kg/m^3 equals 1.126 Bcm/year or 3.085 million m^3/d of feed gas. Nigeria's estimated volume of gas flared in 2025 is 7.02 Bcm (19.2 million m^3/d) less than the existing ullage in NLNG (23.1 million m^3/d) before the hybrid expansion project.

was globally ranked 292nd. Flaring declined since 2019, but recently shows rising trend (Figure 23). Agbami flare variability is high compared to the other four assets and continued to rise to peak in 2024, 20% higher than in 2022 (see also Figure 12). In combination with its high historic flare rate, it indicates that process instability and upsets (system trips) have been driving Agbami's flaring performance. From 2023 onwards, it appears that Agbami was operated by keeping flare intensity at a more stringent target 15 m^3/m^3 compared to the period prior at 25 m^3/m^3 (2019–2022). Late in 2025, Agbami underwent a five-week Turnaround Maintenance (TAM) shutdown that ran from November 19th through December 27th. Gas flaring levels remained high until June 2026.

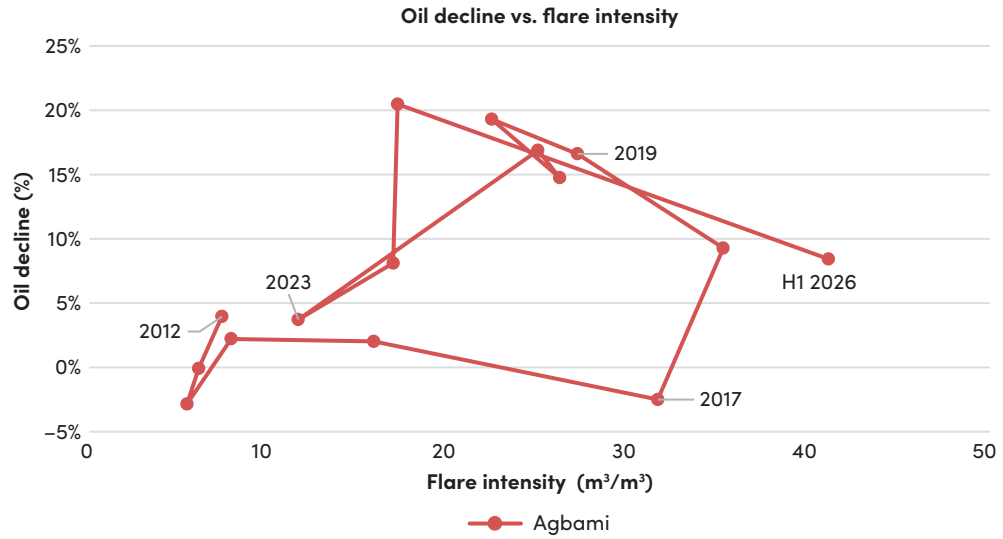
FIGURE 23. Agbami flare performance overview



Notes: Author's illustration, flare data from VIIRS. Agbami monthly average flare rates 2019–H1 2026 in million m^3 (a, top) and long-term trends (b, bottom), with 12-month moving average flare rate (teal), flare variability (green) and monthly poor quality flaring events (red).

A core objective of the late-2025 maintenance campaign was the overhaul of the asset's Gas Turbine Compressors (GTCs). During Q1 2026, these newly serviced and upgraded units underwent extensive commissioning, testing, and fine-tuning. This is likely to have caused trips on the compressor trains with associated gas flaring. Continuous monitoring will establish whether flaring intensity will reduce from 41 m^3/m^3 in H1 2026 to previous level of 15 m^3/m^3 during 2023–2025 (Figure 24, Table 3).

FIGURE 24. Agbami asset oil decline and flare intensity (3-month TMA)



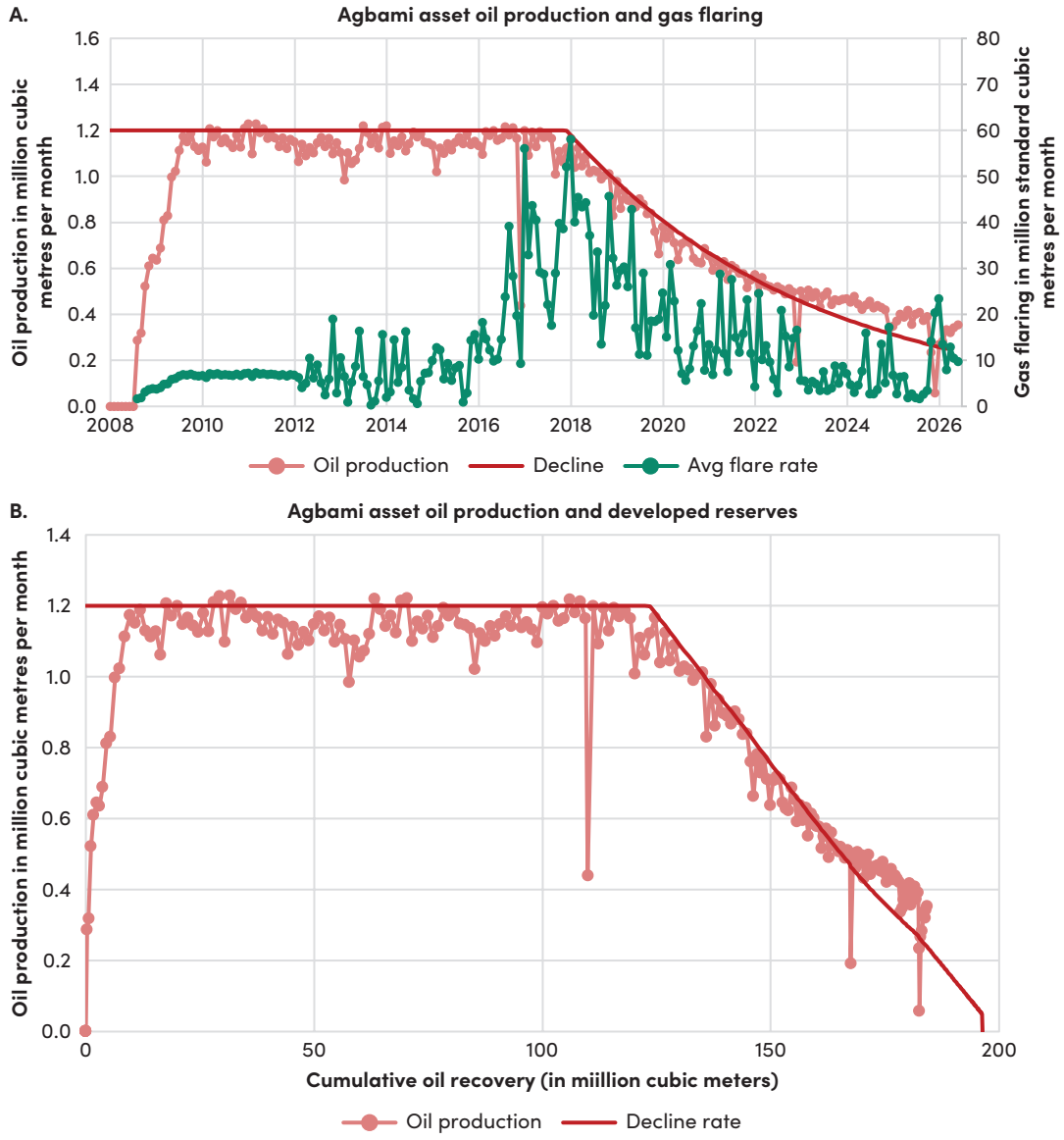
Note: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/.

TABLE 3. Agbami oil production and gas flaring performance (2020–2026 year-to-date)

Agbami	2020	2021	2022	2023	2024	2025	2026
Oil rate (m^3/d)	22,784	19,423	16,141	15,540	14,281	11,356	10,400
Oil decline rate (%)	19.3%	14.8%	16.9%	3.7%	8.1%	20.5%	8.4%
Flare rate (mln m^3/d)	0.509	0.507	0.402	0.180	0.241	0.194	0.427
Flare intensity (m^3/m^3)	22.33	26.11	24.90	11.60	16.86	17.11	41.03
Flare variability (m^3/m^3)	6.51	5.12	6.53	6.34	8.13	6.76	4.31
Routine Flaring (%)	66.0%	61.7%	55.9%	71.7%	45.6%	61.5%	69.3%

The reduction in Agbami flaring since 2022 appears to have coincided with the start of a period of improved oil recovery with lower oil decline rates, (Figure 25). The relationship between flaring and oil decline rates was described in Section 7.

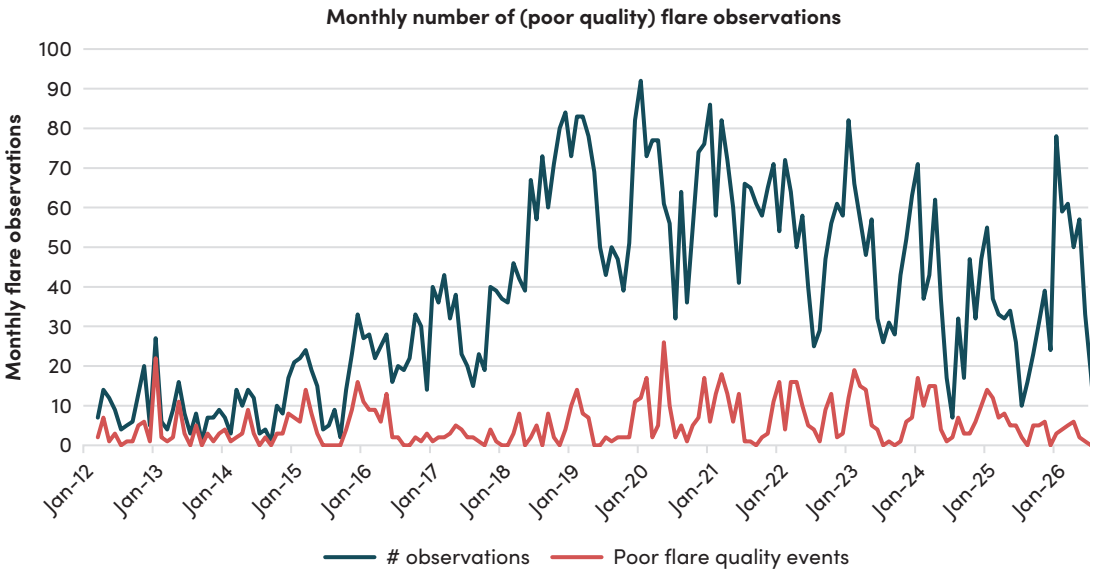
FIGURE 25. Agbami asset oil production, decline and flare rate



Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/. Low flaring period commenced January 2023, when Agbami had produced 168 mln m^3 oil.

A further aspect in the flare analysis is the assessment of flare quality, i.e. the extent to which flare gas is fully or partially combusted. After Yoho, Agbami has 2nd highest number (and %) poor flaring events among the five offshore super-emitters (Figure 26).

FIGURE 26. Agbami poor flare quality observations



Note: Author's illustration, flare data from VIIRS.

A point to note is that Chevron is an important participant in natural gas projects in Nigeria. This includes projects such as the Escravos Gas Plant (EGP), the Escravos Gas-to-Liquids (EGTL) facility and the Sonam Field Development Project.[32] Gas-focused projects such as the EGP and EGTL have reduced gas flaring, improved environmental outcomes, and supplied cleaner fuels. With a 36.7% interest, Chevron is the largest shareholder in the West African Gas Pipeline Company Limited, which owns and operates the 421-mile (678-km) West African Gas Pipeline. The pipeline supplies customers in Benin, Ghana and Togo with Nigerian natural gas for power generation and industrial applications. Fostering regional economic integration and development, the pipeline has the capacity to transport approximately 170 million cubic feet of natural gas per day.

Notwithstanding Chevron's roles in gas monetization projects in Nigeria, Agbami is Nigeria's largest gas flaring asset 2017–2024 and has currently no gas monetization scheme. It relies fully on gas reinjection to preserve produced gas as a future development resource.

32 CNL operates the EGP, which has a total capacity of 680 million cubic feet per day of natural gas and LPG and a condensate export capacity of 58,000 barrels per day. Chevron and the NNPC operate the EGTL facility, a 33,000-barrel-per-day gas-to-liquids plant. The Sonam Field Development Project is designed to process natural gas through the EGP and deliver it to the domestic gas market. Net production at the 40% owned and operated project averaged 11,000 barrels of liquids per day and 89 MMscf/d in 2019.

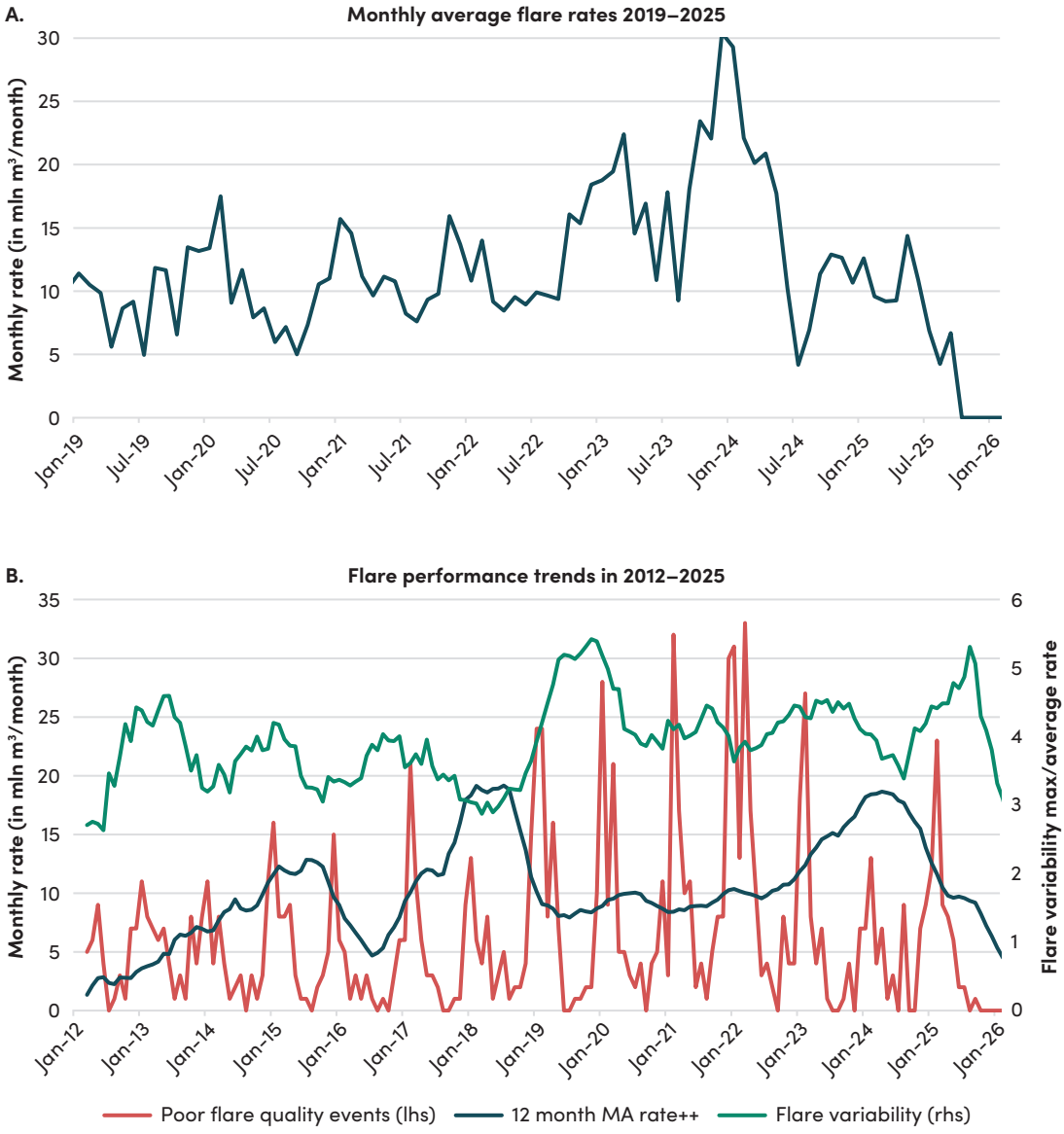
In 2024, Chevron renewed the Agbami deepwater concession through 2044, increasing its reserves by 51 million barrels.[33] **The production license extension provides long horizon opportunities such as the Agbami Gas Project** to eliminate routine flaring and provide compression redundancy and reliability for future gas export. Under the NNPC Gas Master Plan 2026 released in January, the government and operators like Chevron are committed to ending routine gas flaring by 2027. The Agbami Gas project will increase gas compression capacity of Agbami FPSO to 600 MMscf/d with the addition of a new 150 MMscf/d gas turbine compressor and associated gas dehydration system.[34] The enhancements also include vapor recovery systems to reduce flaring during maintenance. Cleaning flare gas from liquids is expected to improve flare quality. The Agbami Gas Project aims to transition the field from a "zero-export" model to a commercial gas supplier, exporting up to 150 MMscf/d of gas. New subsea equipment is installed that could link Agbami with existing offshore gas gathering networks. The processing upgrades will allow export quality gas to be exported from Agbami into the offshore gas aggregation facility to bring the gas to shore. In addition to gas monetization, Agbami field life extension may also be achieved through Chevron's plans to deploy a drilling rig in late 2026 to appraise Ikija discovery near the Agbami hub to unlock further reserves.

8.2 Yoho

Yoho is one of the oldest and more mature oil producing assets offshore Nigeria. The Yoho field lies in Oil Mining Lease (OML) 104, 25 miles offshore in eastern Nigeria, 41 miles southwest of the Qua Iboe Terminal. It is a shallow-water asset developed by Bridge Linked Platform (BLP) infrastructure, utilizing wellhead platforms and with oil stored and offloaded through a Floating Storage and Offloading (FSO) vessel. In the 2023 OPM report, Yoho was evaluated as Nigeria's 7th largest flare, ranking 119th globally. After Agbami, Yoho was the 2nd largest offshore super-emitter evaluated in the OPM study. Despite being located much closer to the coast and nearer to the NLNG gas plant than Bonga, no gas monetization/conservation scheme had been implemented for Yoho by operator ExxonMobil. The OPM study highlighted Yoho's increasing flare intensity and questioned when its oil production would be discontinued, because the amount of gas flared is considered too excessive.

33 https://www.chevron.com/newsroom/media/publications/annual-report (2025).
34 https://ariosh.com/wp-content/uploads/2023/07/Chevron_Agbami_Gas_Project.pdf.

FIGURE 27. Yoho flare performance overview



Notes: Author's illustration, flare data from VIIRS. Yoho monthly average flare rates 2019–2025 in million m^3 (a, top) and long-term trends (b, bottom), with 12-month moving average flare rate (teal), flare variability (green) and monthly poor quality flaring events (red).

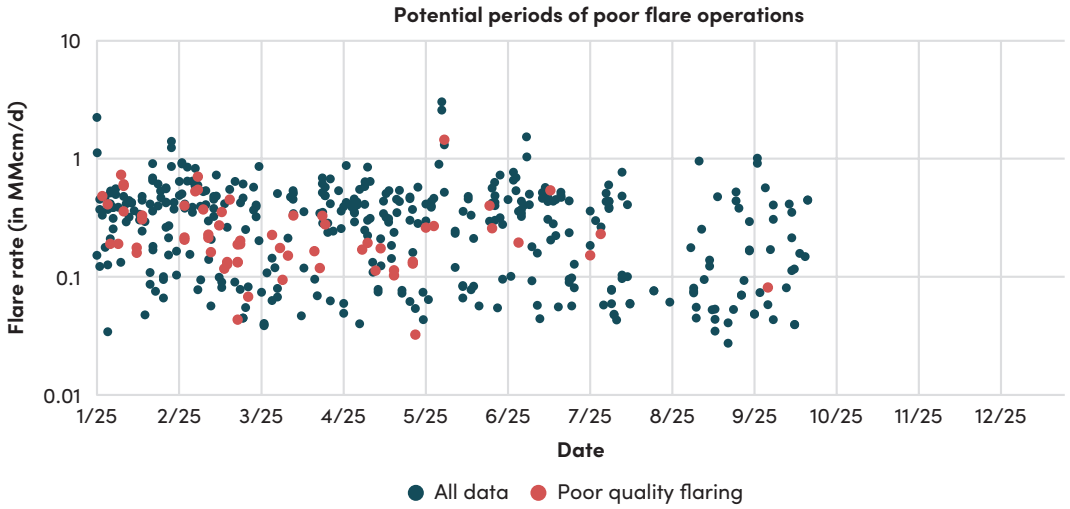
This liability was highlighted by Wood Mackenzie, reflecting on Seplat Energy's bid to acquire ExxonMobil's assets in 2022: "*ExxonMobil refused to be drawn into the high-risk domestic gas market and had no exposure to NLNG. As a result, the acreage has the highest concentration of gas flaring in the country. Seplat, a listed company, will need to tackle this immediately*".[35] After two years of

35 https://www.thisdaylive.com/2022/03/02/seplat-and-exxonmobil-deal-positive-for-nigerian-economy-says-wood-mackenzie/.

regulatory delays, approval for Seplat's acquisition of Yoho from ExxonMobil was obtained in October 2024. During the period preceding the approval, Yoho's flare performance deteriorated notably.

When Seplat commenced operatorship in December 2024, flare variability (an indicator of production instabilities) jumped, reaching a peak in September 2025. A **fire occurred on Yoho** on 27 September 2025 and this coincides with the last satellite recorded flare rate. Yoho remains shut-in to Q2 2026 for repairs and added investment in integrity. Meanwhile, following the 2024 license award by the Federal Government of Nigeria, UTM ltd is proceeding to Final Investment Decision for its **Floating LNG (FLNG) Facility to monetize Yoho's remaining gas** under a gas sales agreement with Seplat.

FIGURE 28. Individual flare measurements of Yoho in 2025



Notes: Author's illustration, flare data from VIIRS. A sudden halt in flare data is observed with the last data point on 26 September 2025 a day prior to the fire and subsequent shut=in of the asset.

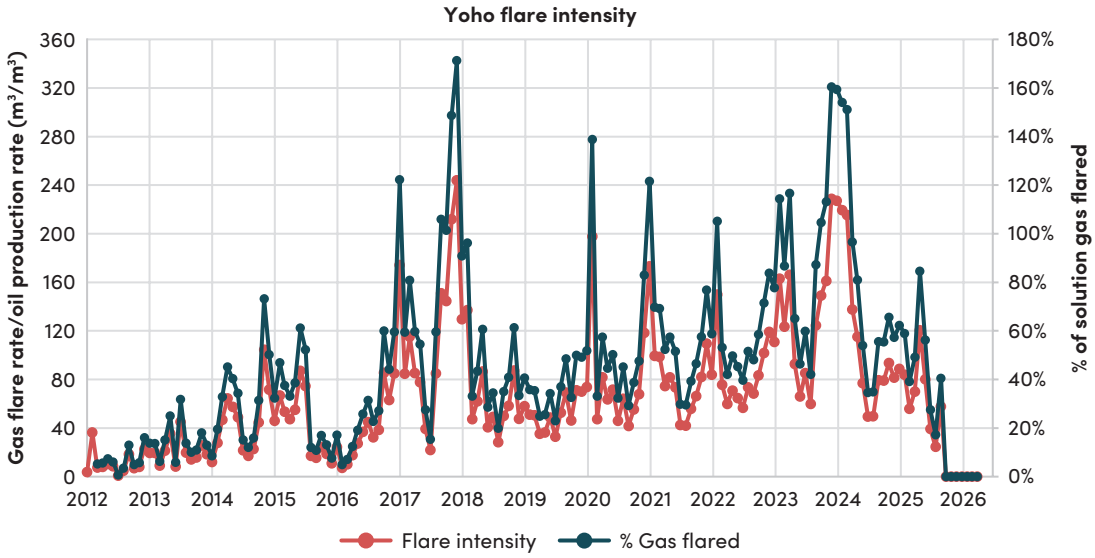
TABLE 4. Yoho oil production and gas flaring performance (2020–2026 year-to-date)

Yoho	2020	2021	2022	2023	2024	2025	2026
Oil rate (m^3/d)	3,997	4,359	4,479	4,678	3,973	3,036	0
Oil decline rate (%)	27.5%	–9.1%	–2.7%	–4.4%	15.1%	23.6%	100%
Flare rate (mln m^3/d)	0.284	0.337	0.368	0.573	0.455	0.208	0
Flare intensity (m^3/m^3)	71.04	77.33	82.12	122.54	114.60	68.59	–
Flare variability (m^3/m^3)	3.82	4.01	4.45	4.11	4.19	5.07	–
Routine Flaring (%)	73.4%	73.8%	69.9%	72.6%	75.5%	73.5%	–

Figure 29 shows the degree of produced gas flared compared to the amount of oil produced (i.e. flare intensity) and as percentage of the amount of solution gas produced. The results show that Yoho regularly flared the majority of its solution gas and at several times even more that 100%

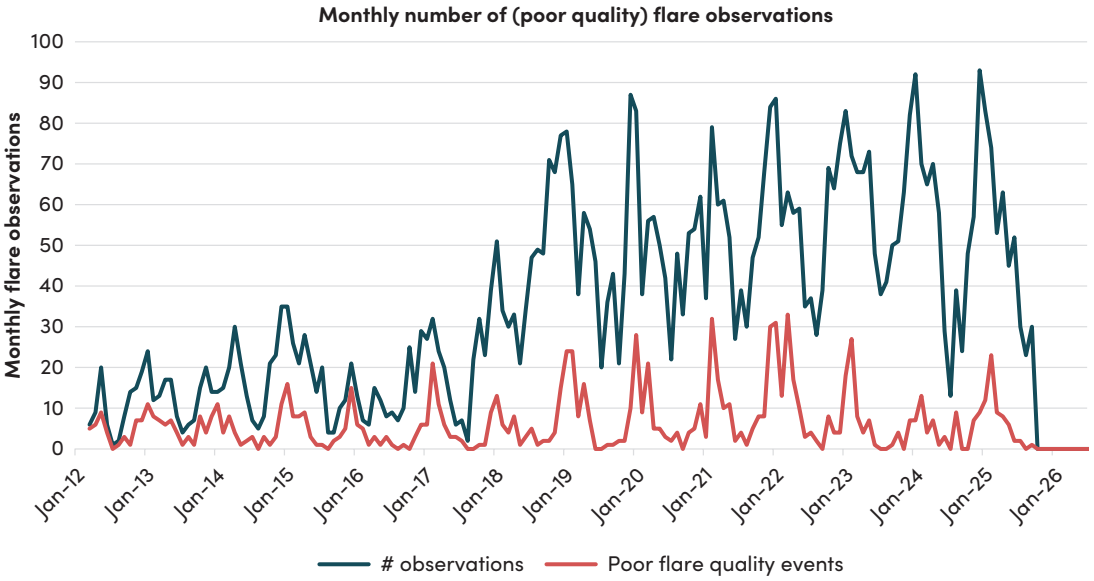
(i.e. also excess free gas produced is flared). During October 2023 to April 2024, a period exceeding half a year, Yoho flared more than all solution gas produced. Compared to the other four offshore assets analyzed, Yoho has the most observed poor-quality flaring events, up to 51% per month, and on average 17.4% of all flare observations, Figure 30.

FIGURE 29. Yoho asset flare intensity and percentage of solution gas flared



Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/. Assumes a solution gas-oil ratio of 800 scf/bbl.

FIGURE 30. Yoho poor flare quality observations

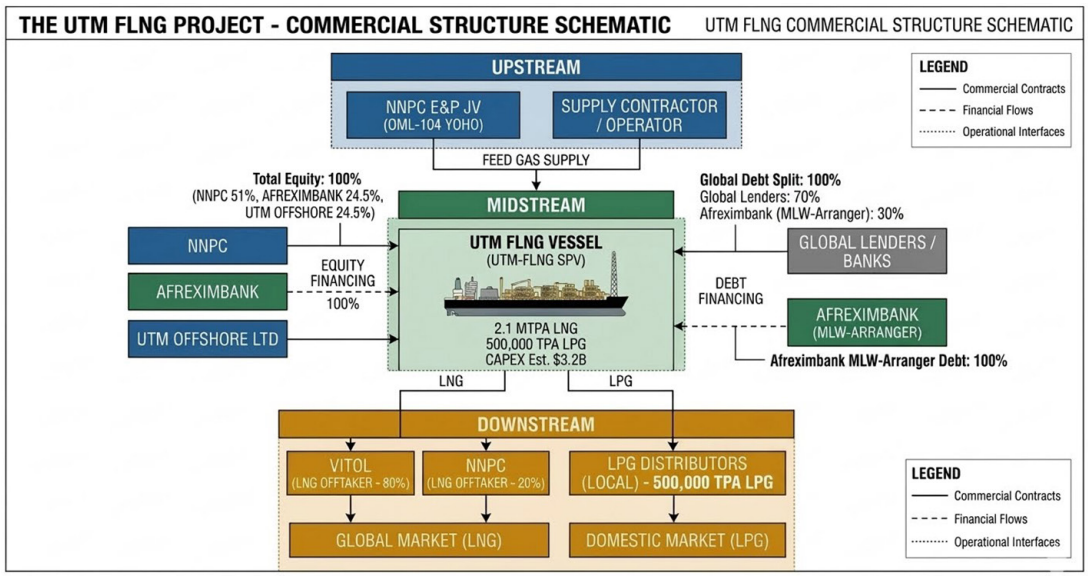


Note: Author's illustration, flare data from VIIRS.

It is positive therefore that UTM's "Nigeria's first" FLNG development is making good progress towards project delivery.[36] The FLNG construction project is split across major Engineering, Procurement, Construction, Installation, and Commissioning (EPCIC) partners: Hull Fabrication is handled by COSCO Shipyard in China, engineering & topsides are managed by JGC Holdings (Japan) and Technip Energies (France), who completed the Front-End Engineering Design (FEED) in late 2023. Once the floating facility is built and fully integrated, it will be towed and permanently moored at the Yoho Field.

To be successful, Yoho field is to transition from an oil field into a gas field. In September 2024, UTM Offshore Limited obtained the license to operate the new 2.8 mtpa FLNG plant, upgraded from 1.2 mtpa. Engineering work is expected to be completed in 2028, with LNG production due to start in 2029. Afreximbank provided USD 2.1 billion in financing and committed a further USD 3 billion.[37] The FLNG plant is designed to utilise the flared/reinjected gases from the Yoho oil production field into usable products such as LNG, LPG, and condensate (Figure 31). The project dedicates ~0.3 mtpa of LPG for domestic use in Nigeria, lowering reliance on wood and charcoal for cooking (improving indoor air quality).

FIGURE 31. Overview of UTM FLNG venture with commercial, financial and product interfaces



Note: Diagram structurally designed by the author using OpenAI (ChatGPT GPT-4o model, June 2026) based on public project declarations.

36 https://www.offshore-technology.com/projects/utm-flng-facility-nigeria/?cf-view.

37 https://www.reuters.com/business/energy/nigeria-licenses-first-floating-lng-plant-export-domestic-use-2024-09-06/.

A key commercial challenge will be continued commercial alignment between field operator Seplat and LNG operator UTM to optimise the value for the combined asset cluster. Although there is a transfer price for the produced gas, blowing down the reservoir too fast may compromise remaining oil production. Particularly now the Yoho asset is currently unable to continue to produce oil following the fire incident, tail-end oil recovery may partially be recovered as Natural Gas Liquids (NGLs) in UTM's production stream. If the consortium can manage these value optimization challenges, it will set a positive precedent for other such oil-to-gas late field life developments.

8.3 Usan

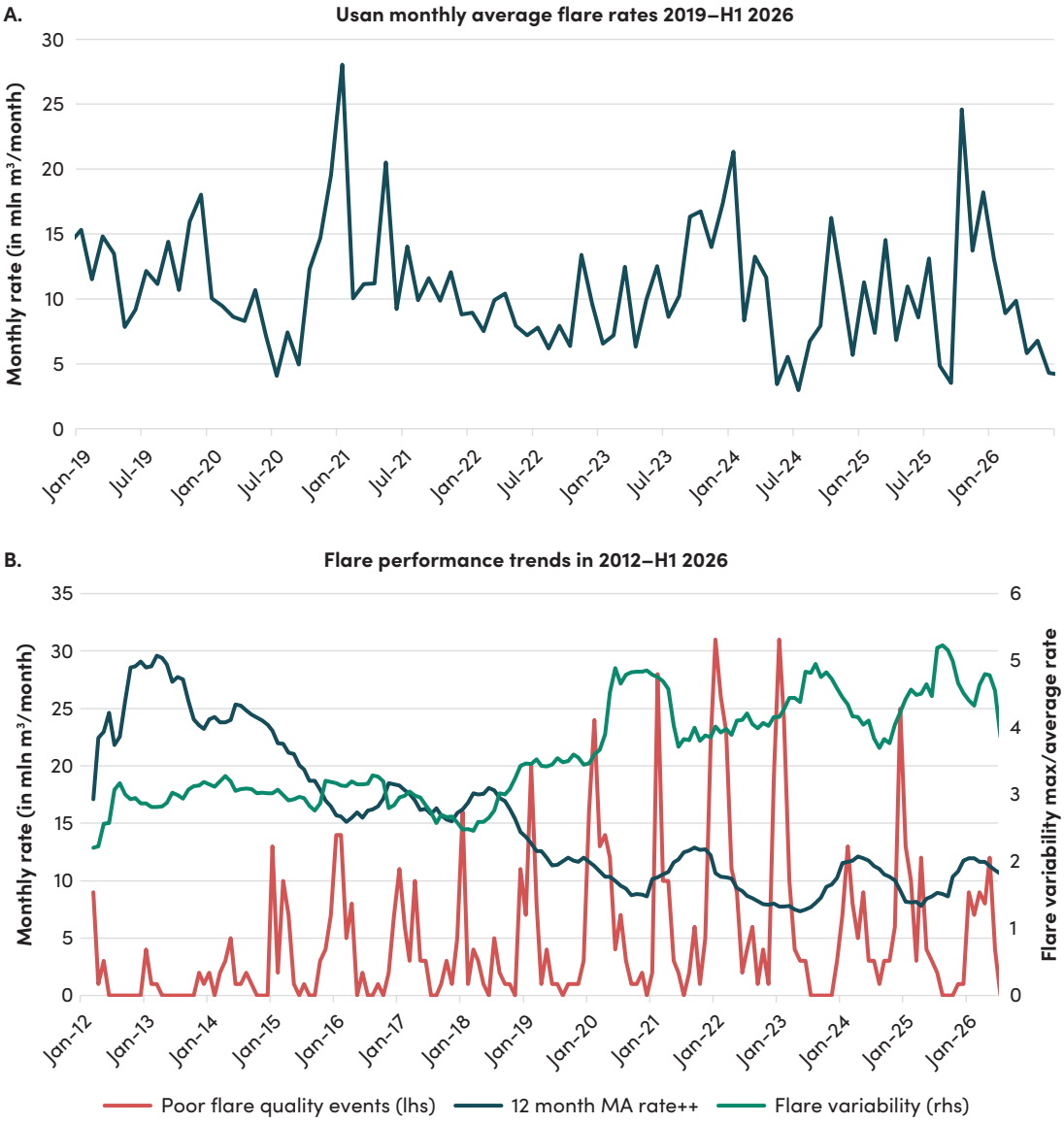
The Usan Field is located in 2,461 feet (750 m) of water, 62 miles (100 km) off the coast of the eastern Niger Delta region. It commenced production in March 2012 and consequently its complete production flaring period has been monitored with VIIRS satellite data. At the time of the OPM onshore report early 2023, Usan was ranked as the third largest super-emitter in Nigeria after Agbami and Yoho. After TotalEnergies failed to sell the Usan asset, it transferred operatorship to Exxon in 2014. Apart from Exxon (30%) and TotalEnergies (20%), remaining working interest is shared between Chevron (30%) and Nexen (CNOOC, 20%).

Usan's high flaring performance was detailed in Total's SEC 2013 filing, being responsible for almost 20% of group's global flaring. It exemplified that Usan had not been performing in line with its development plans as "*a solution that drastically reduces gas flaring and thus minimizes the project's environmental impact*", and approvals thereof. With the transfer of operatorship, Total no longer reports Usan's flaring, while recently Exxon reports its global corporate aggregated gas flaring in its sustainability performance (see below).[38]

By end 2022, Usan FPSO had flared in excess of 2 billion m^3 of gas. This is 2.5 times more than Bonga and 82.5% of the volume flared by Agbami in the same 2012–2022 period, while cumulative oil recovered for Usan by end 2022 was less than a third compared to Bonga and Agbami. Only the Abo asset shows a higher flare intensity than Usan, while Usan flared more than any of the assets during the first ten years (now 14 years) of production.

38 As for each of the five offshore assets, monthly asset flare data are published by NNPC as part of its monthly disclosures, see Appendix A.

FIGURE 32. Usan flare performance overview



Notes: Author's illustration, flare data from VIIRS. Usan monthly average flare rates 2019–H1 2026 in million m³ (a, top) and long-term trends (b, bottom), with 12-month moving average flare rate (teal), flare variability (green) and monthly poor quality flaring events (red).

Usan maintained its ranking as Nigeria's third largest flare in 2023 and was fifth in 2024.[39] In 2025, Usan's flaring was the highest since 2021 and larger than any of the other four assets evaluated. It is also the only asset of the five that increased its flare rate (by 47%) between 2022, when the OPM flaring review was conducted, and 2025, see Table 5.

39 Throughout the period 2017–2024, Usan ranks as Nigeria's sixth largest flare based on undiscounted cumulative gas flare volumes in this period.

TABLE 5. Usan oil production and gas flaring performance (2020–2026 year-to-date)

Usan	2020	2021	2022	2023	2024	2025	2026
Oil rate (m^3/d)	5,913	6,814	7,160	5,404	4,116	4,433	5,189
Oil decline rate (%)	40.5%	–15.2%	–5.1%	24.5%	23.8%	–7.7%	–17.1%
Flare rate (mln m^3/d)	0.283	0.402	0.263	0.337	0.299	0.387	0.252
Flare intensity (m^3/m^3)	47.88	58.93	36.70	62.30	72.67	87.30	48.51
Flare variability (m^3/m^3)	4.85	3.86	4.16	4.59	4.23	4.51	4.77
Routine Flaring (%)	70.0%	76.0%	74.8%	71.9%	74.6%	75.5%	75.8%

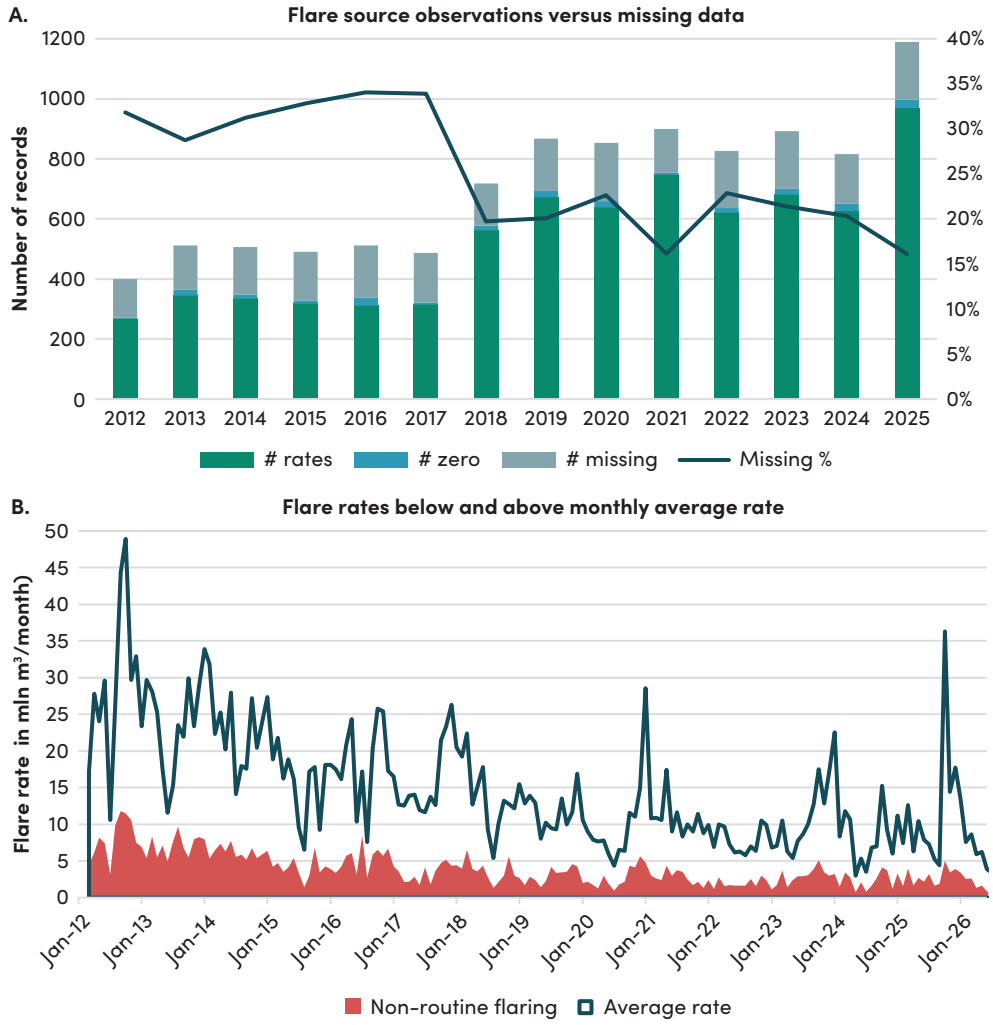
For 2025, Exxon reported routine flaring of 4 MMscf/d across its total global operated portfolio, a reduction of 83% compared to 2024.[40] However, analysis in this paper estimates Usan routine flaring alone at more than 10 MMscf/d for 2025.[41] This example shows **the importance of consistent definitions for routine flaring to avoid the erosion of meaning from sustainability reporting**. To put the reported value of 4 MMscf/d routine flaring in perspective, based on Exxon's own reporting, its routine flaring represents a mere 2.7% of its total global operated flaring volumes.

As the name suggests, and the analysis shows (see Figure 15), routine flaring has significant presence and is persistent. If 97.3% of all flaring is classified to be incidental, i.e. non-routine, it would be expected to see a large variation in daily flare rates (i.e. flare variability) in the range of 10 m^3/m^3 or higher caused by a few flaring events per month. However, this is not what is being observed. Usan's flaring is one among the most regular super-emitter flares evaluated. VIIRS positive flare observations from daily satellite overpasses average 73 per month in 2025 and outweigh zero flare rates 40 to 1 (Figure 33a). The large and increasing number of flare observations provide 9861 data records and 7307 individual flare rate measurements in the 2012–2025 period, sufficient for non-routine flare rate assessment (Figure 33b) and data trending (Figures 34a and b).

40 Exxon reported flaring is on operated basis, not on equity basis. The 2025 reduction in routine flaring can partly be attributed to Yoho divestment; https://corporate.exxonmobil.com/publications/metrics-and-data.

41 Usan routine flaring for 2025 is based on a calculated 75% routine flaring factor, applied to13.67 MMscf/d (Table 5, 0.387 MMscm/d), i.e. 10.3 MMscf/d.

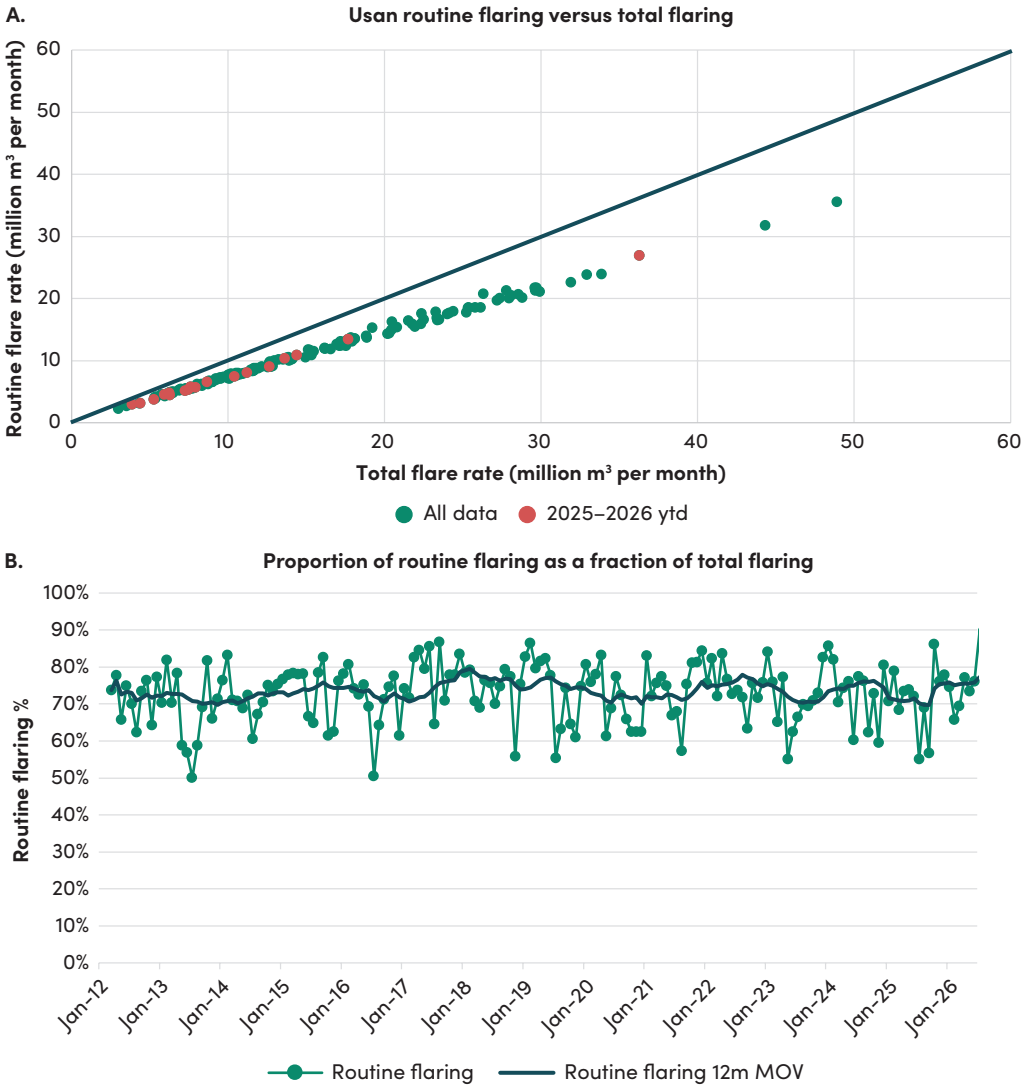
FIGURE 33. Usan flare observations and non-routine flare assessment



Notes: Author's illustration, flare data from VIIRS. Usan annual flare observations, totaling 878 positive rate estimates and 22 zero-rate observations from daily satellite overpasses in 2025 (a, top). Monthly average (teal) and non-routine flare rates (red) during 2012–2026, in million m³/month (b, bottom).[42]

42 10 mln m³/month = 11.6 mln scf/d.

FIGURE 34. Usan routine flaring assessment and trends

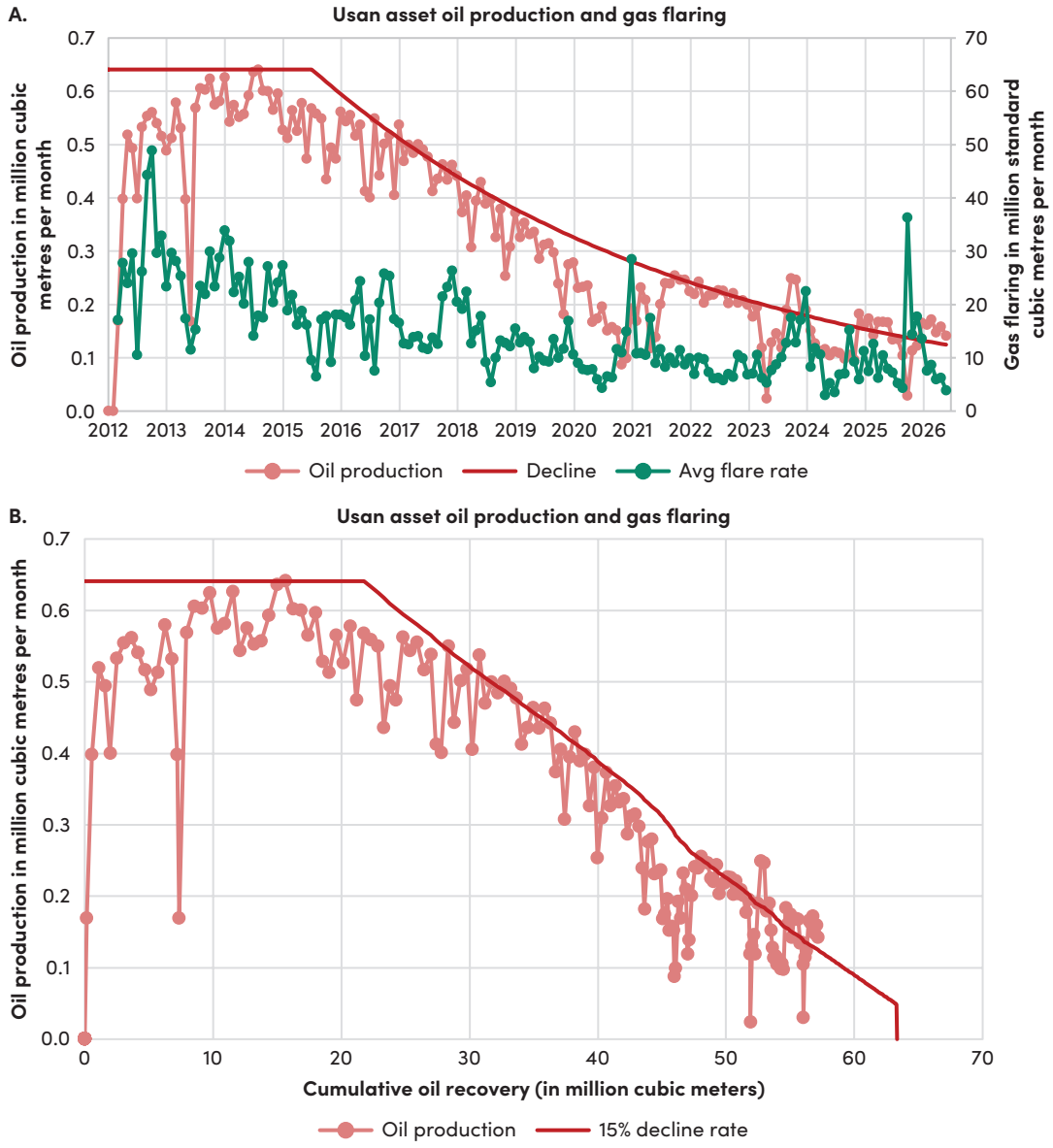


Notes: Author's illustration, flare data from VIIRS. Usan cross-plot of total and routine flare measurements per month (a, top) and monthly percentage routine flaring trend, (b, bottom). The teal line in the bottom graph (a) presents the 100% routine flaring limit.

Little scatter in Usan's routine flare trends is observed. Routine flaring in 2025–2026 follows the same trend as in preceding years. Routine flaring averages 72.7% with a standard deviation of +/– 2.4% and a 95% confidence level for routine flaring range (67.8%, 77.6%) of total flaring for the 2012–2026 period.

In 2025, Usan flare intensity (flare volume divided by oil production) was 102.7 m^3/tn, a factor 25.7 higher than Exxon's corporate reporting value of 4 m^3/tn.

FIGURE 35. Usan asset oil production, decline and flare rate



Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/.

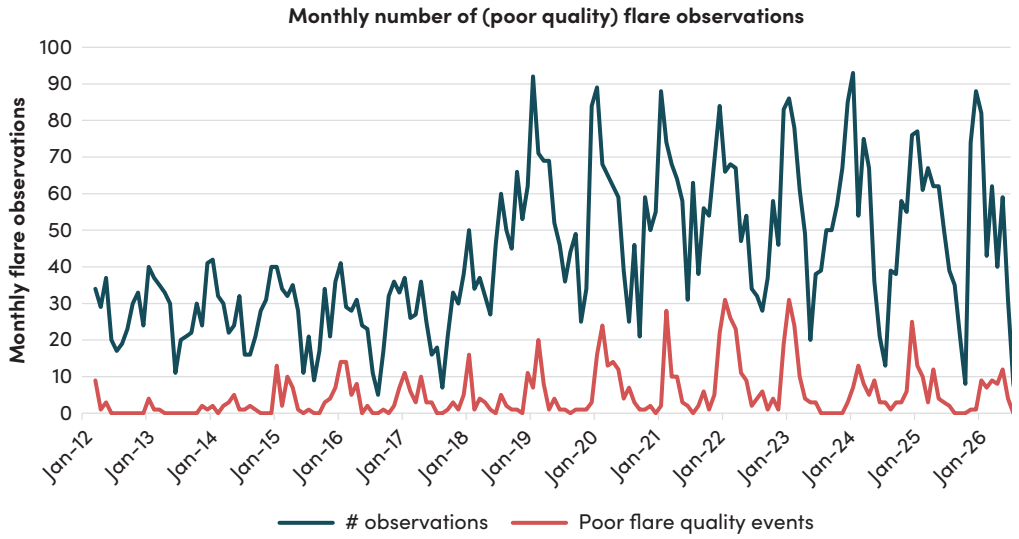
Usan developed reserves are increasingly mature, with 90% of the oil already recovered. Without further investment, economic end of field life could be reached in 2032 (based on an oil cut-off rate of 10,000 bpd).

Usan's production license was scheduled to expire in 2027 but it was renewed early in August 2022 after the fiscal incentives provided by Nigeria's Petroleum Industry Act (PIA) During 2025–2027, Exxon is investing **USD 1.5 billion into revitalizing the Usan asset** to address its production decline.

The company proposed Final Investment Decision (FID) in late Q3 2025, that is subject to final Field Development Plan approval as well as internal and partner funding approvals.[43] Most of the work is focused on infill drilling activities and subsea infrastructure. The Usan FPSO is a potential future hub for development of the nearby Owowo field, a USD 10 billion project expected to add 180,000 bpd of oil production capacity. Although Exxon's main objective is increasing production, the scope is reported to include compression optimization and Gas Turbine Compression (as in Agbami), as well as a Gas Metering Unit. Waste Heat Recovery from the FPSO's gas turbines will provide thermal energy required for the on-board gas processing systems. The drilling and completion of additional gas injection wells (building on the original 19-well injection network) aim to support reservoir pressure and eliminate routine flaring. While initially conserving natural gas, in the longer term the upgrades are designed to position Usan FPSO as a regional processing hub for gas handling, with the infrastructure to ensure that future gas quality meets standards for export to NLNG assets or the domestic market, aligning it with the federal government's gas-to-power initiatives.

The gas export opportunities for the future Usan cluster offer a pathway to stop routine flaring, through the increased gas compression capacity, associated gas dehydration and vapor recovery systems. Cleaning flare gas from liquids is expected to also improve flare quality. For Usan, this is relevant as detailed flare analysis indicates that 11.6% of all flare observations involve poor quality flaring (i.e. incomplete combustion).

FIGURE 36. Usan poor flare quality observations



Note: Author's illustration, flare data from VIIRS.

43 https://www.nuprc.gov.ng/exxonmobil-to-commit-1-5-billion-dollars-investment-in-nigerias-deepwater-oil-fields/.

8.4 Abo

Abo is Nigeria's first deepwater development. The Bergesen Worldwide (BW)-leased Abo FPSO started production in April 2003 and the field is operated by ENI. The processing capacity can handle 45,000 bpd of oil, but produced oil peaked at a production rate of 34,000 bpd (March 2010). Current oil production rate is 7,900 bpd (January to June 2026). Its gas compression capacity design baseline was rated at 44 MMscf/d, but its gas reinjection capacity is limited to 35 MMscf/d. Prior to 2014, gas injection was limited to 12 MMscf/d but this was debottlenecked with a horizonal sidetrack of Abo-9 gas injector well. Operator gas data for Abo during 2022/2023 indicate that the upgraded reinjection capacity had been sustained.

Abo's facilities design appears to have been based on average solution GOR is around 1,100 scf/bbl, which implies that it can only produce 35,000 bbl/d if flaring is to be avoided.[44] However, Abo's production suffers from reservoir gas breakthrough causing producing GOR to exceeds 4,600 scf/bbl (i.e. free gas is produced together with the solution gas), and in 2026 reaching as high as 5,800 scf/bbl. Gas injection constraints therefore continue to limit oil production to 6,800 bpd to avoid flaring.

Actual oil production in 2026 (January to June) averaged 7,900 bpd, exceeding the zero-flaring limit by 1,630 bdp. Based on the producing GOR 5,800 scf/bbl, excess gas of 9.5 MMscf/d has been flared (averaging 8 million m^3 per month). This matches the VIIRS flaring measurements of 7.8 million m^3 per month for this period.

Assuming a commercial break-even limit of 5,000 bpd for Abo to be cash positive, **Abo's high GOR puts it in a bind of a narrow production range (5,000 to 6,800 bpd) to remain profitable and to avoid flaring.** Abo's further development should focus on producing more oil at much lower GOR, increase gas reinjection capacity, or both.

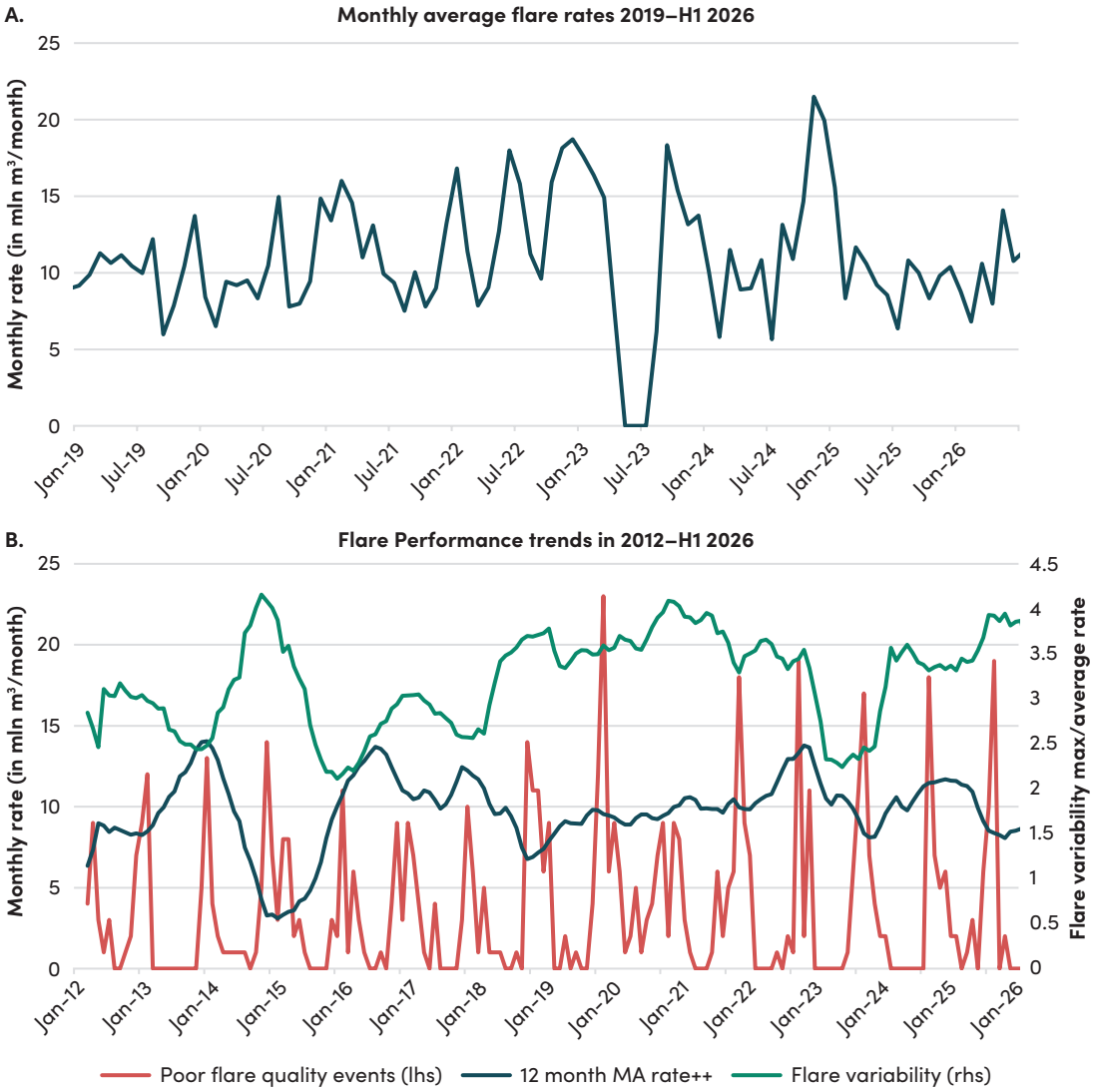
Being the smallest oil producer among the five offshore super-emitters, Abo shows consistently year-on-year the highest flare intensity (Figure 11). In the production period from 2023 until to date, Abo has flared on average 100% of its produced solution gas (which equals 22.2% of its total produced gas).

Although Abo's flaring fell by 30% between 2022 (the last year included in the OPM study) and 2025, the average flare rate during 2023–2025 at 0.326 million m^3/day remained similar to the 0.318 million m^3/day observed in the period 2018–2022.[45]

44 The gas handling includes 4.5 MMscf/d fuel gas that is to be included in the gas handling utilisation, but subtracted from the reinjected gas. Hence 35,000 bbl/d × 1,100 scf/bbl = 38.5 MMscf/d produced gas, less 4.5 MMscf fuel gas results in a gas reinjection volume of 34 MMscf/d close to the capacity limit.

45 These values are close to 10 million m^3 per month as shown in Figure 37a.

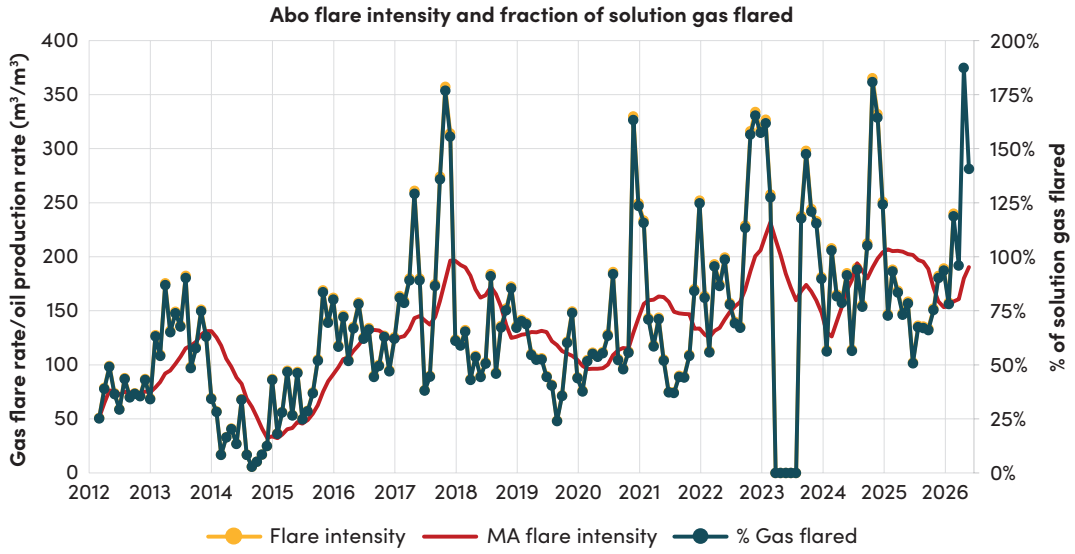
FIGURE 37. Abo flare performance overview



Notes: Author's illustration, flare data from VIIRS. Abo monthly average flare rates 2019–H1 2026 in million m³ (a, top) and long-term trends (b, bottom), with 12-month moving average flare rate (teal), flare variability (green) and monthly poor quality flaring events (red).

Abo's high flare rate (Nigeria 11th largest flare) and rising flare intensity are a concern due to the high percentage of energy lost from gas flaring relative to crude energy content recovered. Based on the observation that Abo is produced under a flare rate constraint, the declining oil rate will cause the flare intensity to rise further over time. Ultimately, this will affect its oil production decline, when in field development opportunities are exhausted. Trend data of Abo's flare intensity and percentage of solution gas flared are presented in Figure 38.

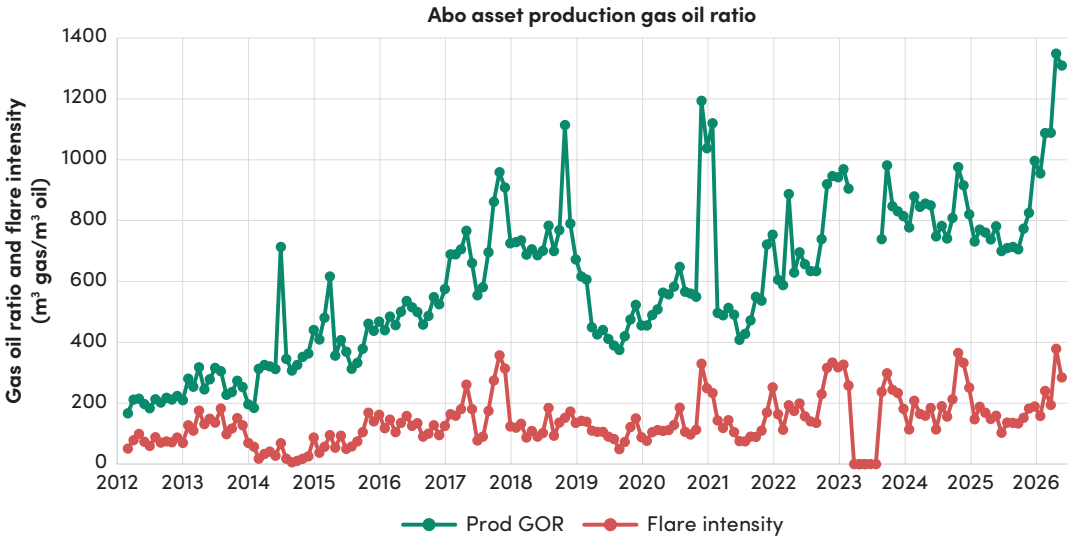
FIGURE 38. Abo asset flare intensity and percentage of solution gas flared



Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/. Assumes a solution gas-oil ratio of 1134 scf/bbl. MA flare intensity represents the 12-month trailing moving average of the monthly flare intensity.

The impact of the increase gas injection capacity early 2014 is shown in Figure 39. Gas flare intensity initially declined but increased again by late 2015 as higher gas-oil ratio production constrained once again the amount of gas that could be reinjected. Gas-oil ratios have been increasing as flare rates, gas injection rates and gas utilization remained relatively constant against a declining oil rate. The amount of gas processing and recycling into the reservoir continues to increase for each barrel of oil produced.

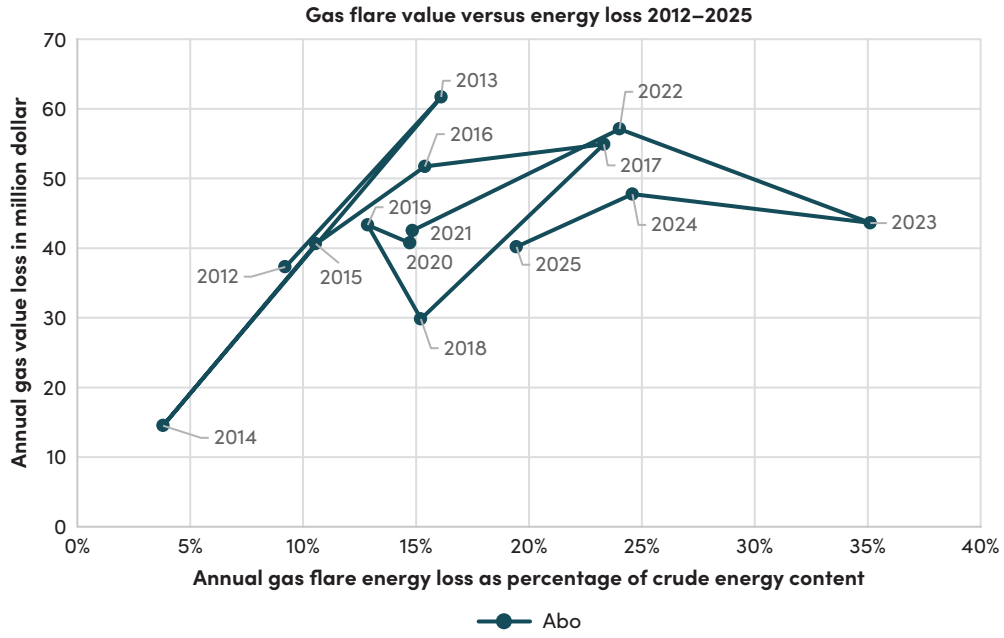
FIGURE 39. Abo calculated produced gas oil ratio



Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/. Produced gas assumptions based on gas injection capacity, fuel gas utilization and flare rates. Abo GOR calibrated https://nnpcgroup.com/documents/ reported gas data.

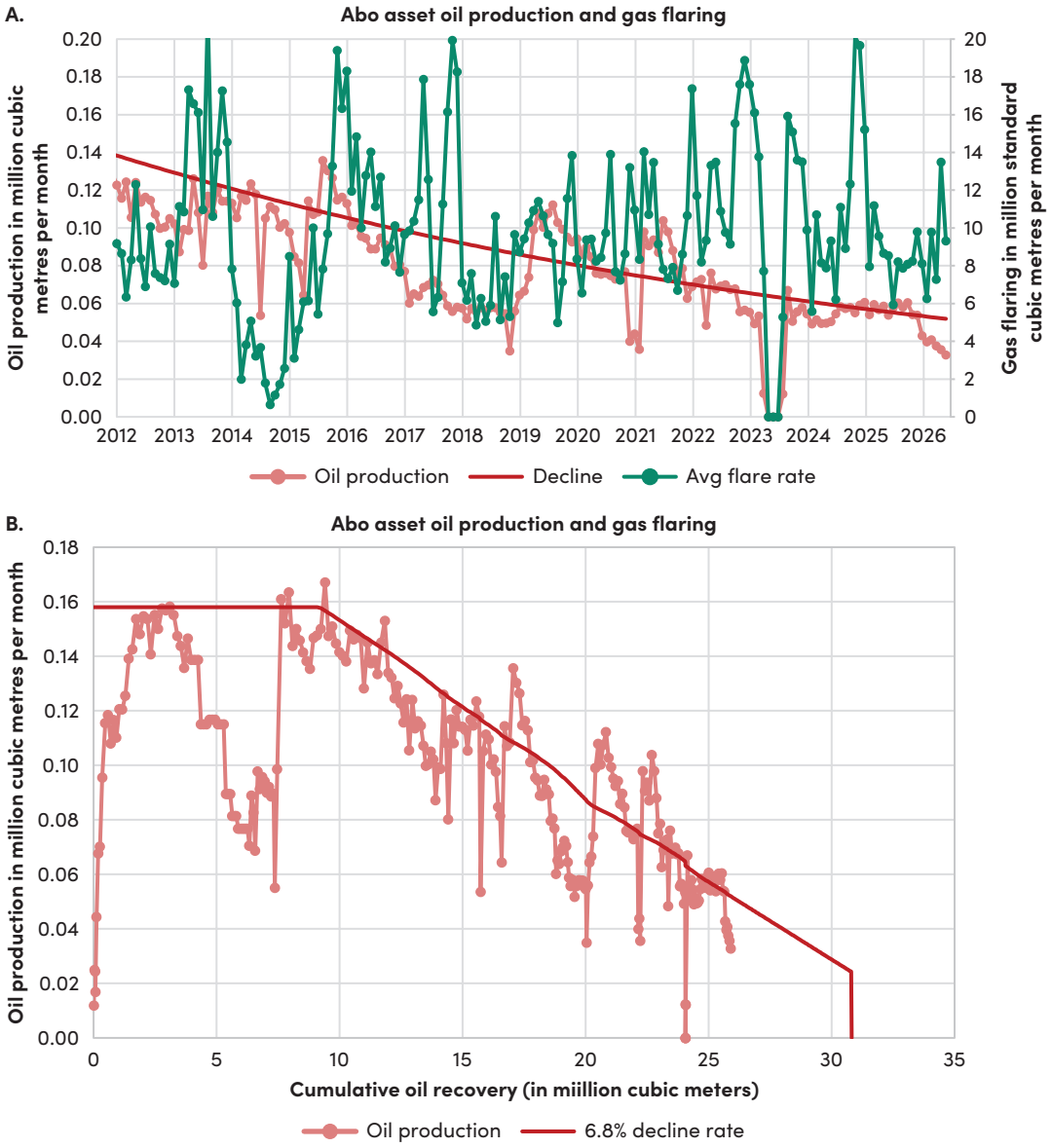
In Section 4 it was highlighted that among the five offshore assets, Abo had the largest amount of energy loss from flaring per barrel produced. Abo's performance evaluation is more intricate due to a large variability in oil rates that need to be considered when evaluating its flare performance, see Figures 40 and 41. As mentioned, 2014 gas injection debottlenecking greatly reduced the gas flaring value loss that reached its peak in 2013. However, flaring rates increased again over time reaching another peak in 2017. The year 2018 brought relief as flare rates were brought under control and oil decline stabilized. The new Abo-12 production well in 2019 not only increased oil production but it was also successful in reducing the production GOR as it accessed an oil saturated area away from the reservoir gas caps. Zonal isolation and 'drawdown management' further helped creating a period of more stable performance during 2019–2021. Commercial and regulatory uncertainty affected investment in the field and topsides. The lease contract with BW Offshore was extended several times for short periods leading up to the field (OML) license extension in August 2022.

FIGURE 40. Gas flare energy and value loss trends for Abo asset



Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/. Abo had a five-month shutdown in 2023.

FIGURE 41. Abo asset oil production, decline and flare rate

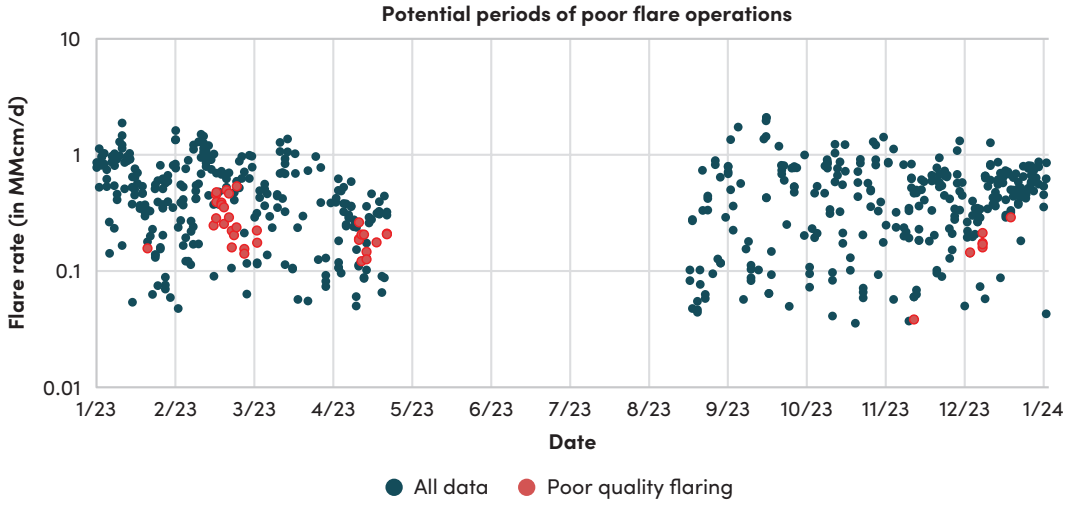


Note: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/.

Operating on short-term lease extensions restricted the FPSO and field operators from executing long-term asset integrity overhauls. Mechanical fatigue on the aging subsea umbilical systems and topside separation modules led to frequent unplanned operational shutdowns, which directly caused sharp dips in daily throughput. Abo field's production license (Oil Mining Lease 125/OML 125) was officially renewed and extended in August 2022 for a period of 20 years. This facilitated the commercial sale and operational lease transfer of the Abo FPSO from BW Offshore

to STAC Marine in 2023.[46] With the renewed regulatory and commercial clarity, a major shutdown was carried out to resolve a multi-year backlog of deferred maintenance from the pandemic era and upgrade the unit to a Full-Term 5-Year Class Certification awarded by DNV. From the raw flare data in Figure 42, Abo's close-in period can be clearly observed (to the day), from 26 April 2023 to 21 August 2023.

FIGURE 42. Daily flare observations for Abo in 2023



Note: Author's illustration, flare data from VIIRS.

In response to the 2023 OPM report, ENI responded in 2023 that "*Abo FPSO is currently under total shutdown, which has been planned and implemented to improve both, HSE and operational performance (even to the detriment of Production)* [...] *A third Compressor is being installed to have redundancy during maintenance activities and reduce flaring; Following the above actions, for which we will have a clear picture within end of the current year, we will be able to define further solutions and strengthen the current strategies to improve our emissions framework*".

However, after the process upgrades the significant flare reductions promised have not materialized. In the 24 months leading up to the shutdown, the total volume of natural gas flared was 0.286 billion cubic meters (Bcm), in the 24 months after the shutdown it was 0.266 Bcm, a reduction of 7%.[47] Neither did flare quality or flare variability change before and after the shutdown. Further analysis will show whether Abo's flare intensity improved after the shutdown.

46 The FPSO was renamed 'FPSO Mayo Abo'.

47 The average 24-month flare rate before and after the shutdown was 11.92 versus 11.08 million m^3 per month, respectively.

TABLE 6. Abo oil production and gas flaring performance (2020–2026 year-to-date)

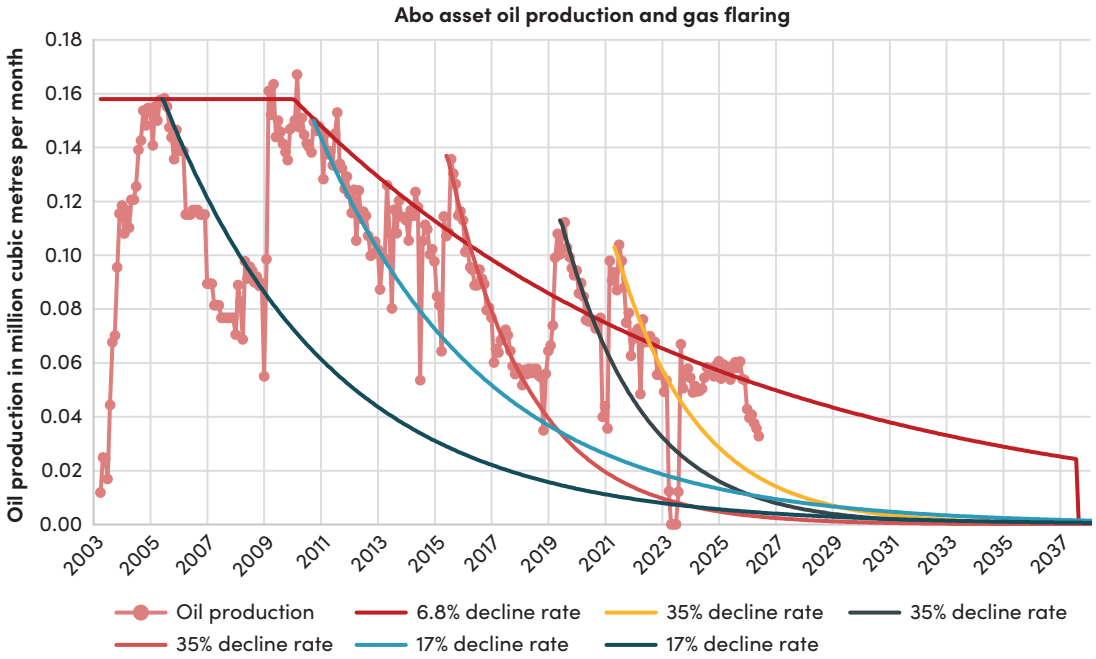
Abo	2020	2021	2022	2023	2024	2025	2026
Oil rate (m^3/d)	2,516	2,616	2,170	1,134	1,768	1,885	1,256
Oil decline rate (%)	18.8%	–4.0%	17.1%	47.8%	–56.0%	–6.6%	33.4%
Flare rate (mln m^3/d)	0.303	0.317	0.425	0.325	0.355	0.299	0.297
Flare intensity (m^3/m^3)	120.26	121.09	195.99	286.60	200.64	158.76	236.52
Flare variability (m^3/m^3)	3.90	3.75	3.33	3.17	3.41	3.68	3.72
Routine Flaring (%)	70.3%	71.6%	74.6%	76.4%	76.1%	74.6%	74.1%

From late 2025 and persisting in 2026, Abo oil rates declined significantly, such that the average oil rate is 25% less than when production stabilized after the shutdown (late 2023–early 2024). The challenge for Abo is to find new in-field and near-field oil potential to develop and tie-in to the facility. Oil production improvement activities show increased rates of decline (35% per year), yet are supporting an overall moderate field decline of 6.8% (see Figure 43). If Abo can maintain this moderate field decline, it can have a significant remaining field life expectancy. However, the ongoing flaring has removed 2.6 billion m^3 of reservoir pressure supporting gas from the field. **Unless gas flaring is stopped, well deliverability will continue to suffer due to reservoir pressure decline and high GOR production in a gas injection constrained facility. Well sidetracks and recompletions may be subeconomic**. If a sizeable near-field oil accumulation at original reservoir pressure can be found and developed, this could serve as the new baseload production allowing existing wells to be choked to optimise ultimate recovery.

ENI has set itself a zero routine flaring target for 80% reduction in 2025 and zero routine flaring taking effect from 2026 onwards.[48] ENI's 2025 corporate target for the volume of hydrocarbons sent to flaring was set at 470 million m^3, while VNF measured flare data for Abo in 2025 was 110 million m^3 (100% operated).[49]

48 ENI sustainability report for 2025, https://www.eni.com/website/eni-for/2025/en/.
49 Abo's reported flare data are lower than measured by VNF.

FIGURE 43. Oil production with field and activity decline curves for Abo



Note: Author's illustration, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/.

Appendix A provides more detail on a comparison of VNF flare data with reported flare data. Among the assets analyzed, Abo is the only asset whereby reported flare data is lower than VNF data. The other assets in contrast show higher reported flare data.

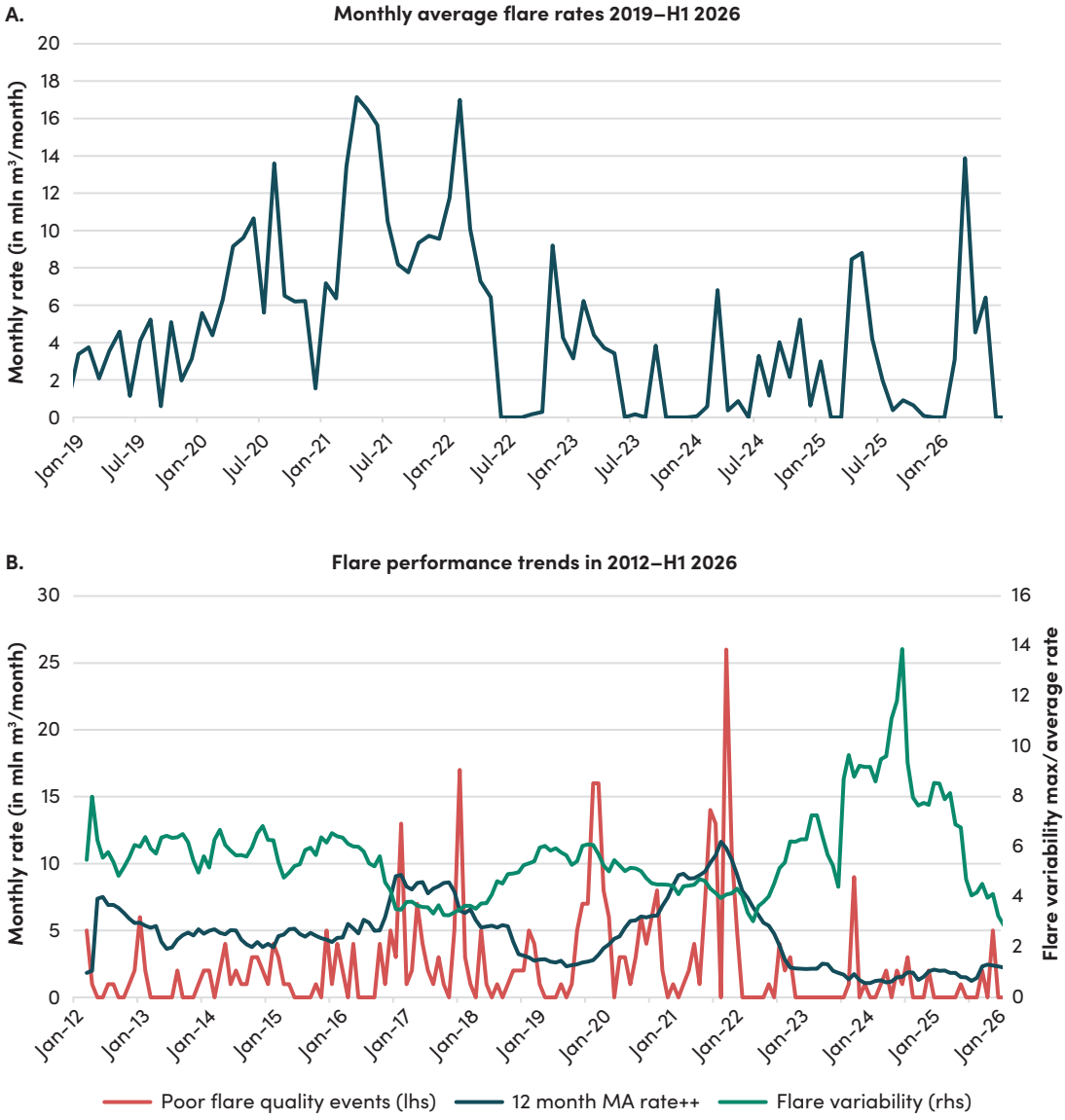
8.5 Bonga

Bonga is Shell's main oil and gas producing hub located offshore in Nigeria. Produced fluids are processed on the Floating Production, Storage and Offloading (FPSO) facility. Natural gas is exported to the NLNG facility on Bonny Island, where it is further processed into LNG and exported (Spain and Portugal are the NLNG's largest customers).

Because Bonga has a gas export scheme, it should not have a super-emitter flare, but up to mid 2022 its gas flaring was highly substantial. From July 2022 onwards, a clear break in flaring trend is visible, see Figure 44. While in 2021 Bonga flare ranked 258th globally and 22nd in Nigeria, in 2024 its ranking had dropped to 2758th and 113th, respectively. As reported previously in the OPM study, Bonga's high flaring rates had been due to a range of technical failures, including low-pressure gas compressor breakdown in 2021, off-specification gas dehydration early 2022 and progressive deterioration of the subsea gas export riser elastomer seal, first detected in late 2019. This is when Bonga gas flaring started to rise again, after low levels in the latter half of 2018 and throughout 2019. Delayed repairs of the gas export riser reduced gas exports while oil production continued and much

gas was flared until July 2022. Bonga's voluntary ("routine") flaring in 2021 was highest since its satellite monitoring started in 2012. The evaluation also shows most poor flare quality events in the same period, particularly coinciding with the gas dehydration failure.

FIGURE 44. Bonga flare performance overview



Notes: Author's illustration, flare data from VIIRS. Usan monthly average flare rates 2019–H1 2026 in million m³ (a, top) and long-term trends (b, bottom), with 12-month moving average flare rate (teal), flare variability (green) and monthly poor quality flaring events (red).

Significant commercial and legal disputes between Shell and the Nigerian government contributed to the technical operational performance challenges. The disputes centered on two key issues, a USD 3.6 billion environmental oil spill that had occurred in 2011 and Production Sharing Contract (PSC) disagreements over operating costs and profit allocation.

The USD 3.6 billion penalty was never paid by Shell.[50] While local courts initially sided with the government, Shell ultimately won a significant victory in the UK Supreme Court in May 2023, ruling that Nigerian landowners filed their claims too late under limitation laws.[51,52]

Negotiations on the PSC disputes between NNPC and Shell became deadlocked. In 2009 Shell initiated international arbitration proceedings and tribunals to settle commercial entitlements on the OML 118 block where Bonga is located. The arbitrators favoured the Shell consortium and ruled breach of contract by NNPC. The consortium was awarded USD 1.8 in damages that subsequently rose to USD 2.7 billion by 2018 due to accrued interest.[53] The Nigerian Court of Appeal later struck down the awards, ruling that the arbitration tribunal had no jurisdiction as the PSC allocation disputes were fundamentally a tax dispute. Concurrently, Shell and ExxonMobil launched enforcement actions in the U.S. and UK court systems to forcefully collect on the awards by targeting NNPC's foreign assets. A severe legal deadlock threatened both Nigeria's economic interests and the international oil companies' (IOCs) future security in the country. Following enactment of Nigeria's Petroleum Industry Act (PIA), the parties opted for a comprehensive commercial settlement to break the gridlock. In August 2022, the parties executed renegotiated, fully termed PSC leases. By putting an end to the multi-billion-dollar arbitral hostilities, **a stable investment climate was restored. This directly paved the way for critical project expansions**, such as Shell's final investment decision on the Bonga North project and its subsequent acquisition of an increased 65% interest in the OML 118 block when TotalEnergies sold its 12.5% interest.[54]

While the commercial and legal disputes were extreme for OML 118 (Bonga), similar delays in asset investment were observed in other assets facing license renewal and/or unresolved disputes (Agbami, Usan, Abo). **Against prolonged uncertainty whether production licenses would be extended, several years before the licenses are due to expire, license holders are reluctant to invest in asset integrity interventions, repairs, production improvement and hence flaring reduction measures**. The flare analyses results reflect this, with significantly higher flare rates before license extensions compared to the periods thereafter. Hence, there are hidden costs to commercial and legal disputes that affect oil production decline (and reserves), gas wastage due to flaring and therefore current and future taxable income.

50 https://www.premiumtimesng.com/news/top-news/665742-bonga-oil-spill-niger-delta-communities-protest-in-abuja-over-3-6bn-shell-award.html?tztc=1.

51 In 2011, a 40,000 bbl oil leak occurred in one of three flexible export loading lines connecting the Bonga FPSO to a Single Point Mooring (SPM) buoy. The rupture happened near the surface of the water during a cargo transfer, approximately 360 metres out from the main FPSO vessel as oil was being pumped toward MV Northia tanker.

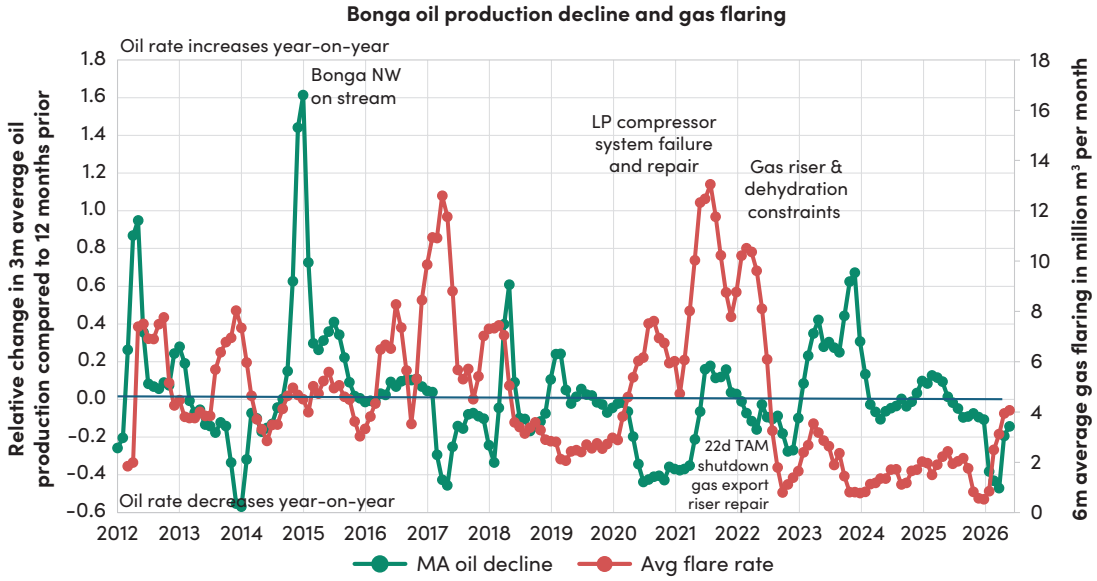
52 https://www.reuters.com/business/energy/shell-wins-uk-supreme-court-case-2011-oil-spill-off-nigerian-coast-2023-05-10/.

53 https://jusmundi.com/en/document/decision/en-1-shell-nigeria-exploration-and-production-company-ltd-2-esso-exploration-and-production-nigeria-deepwater-ltd-3-nigerian-agip-exploration-ltd-4-total-e-p-nigeria-ltd-v-nigerian-national-petroleum-corporation-partial-award-thursday-30th-may-2013.

54 TotalEnergies divested its 12.5% share for USD 510 million in November 2025, as part of a broader corporate strategy to streamline its portfolio and prioritize lower-cost, lower-emission offshore assets. Shell acquired 10% (increasing its interest from 55% to 65%) and ENI (Agip) 2.5% (from 12.5% to 15%) after pre-emption of the Shell-TotalEnergies deal, see https://totalenergies.com/newsroom/nigeria-totalenergies-divests-its-non-operated-interest-bonga-field/?lang=eng.

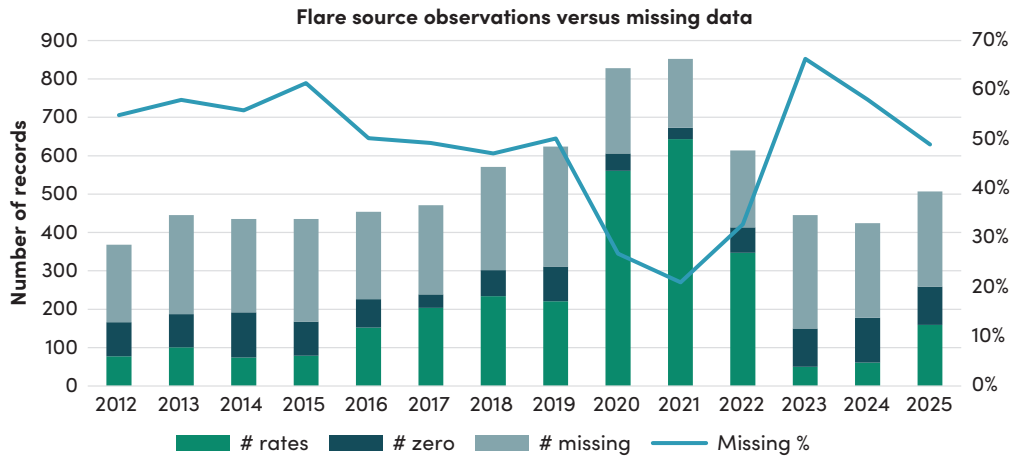
Shell provided comments on EnergyCC's 2023 OPM report that included Bonga. In its comments, **Shell promised to reduce flaring** from a combination of measures, including improvements on its low-pressure gas compression system (2021/2022), improved operational efficiency through resolving asset integrity issues, and the execution of a **pilot flare elimination project**. The latest flare analysis indicates that Shell's stated commitment to reduce Bonga's flaring is paying dividends (Figure 45). Satellite data shows that during the last 3 years (2023–2025) the average annual amount of gas flared reduced to 19.5 million m^3 compared to 83.1 million m^3 in the three years prior (2020–2022), a reduction by 77%. It is not clear if Shell has implemented its pilot flare elimination project, but it is noteworthy that Bonga not only reduced its flare rates, also the number of flare observations radically decreased, see Figure 46. This indicates a structural improvement in flaring operations that hopefully will be sustained going forward.

FIGURE 45. Bonga field activities affecting oil production and gas flaring rates



Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/. Oil rate change on left axis, flare rate on right axis.

FIGURE 46. Bonga flare observations



Notes: Author's illustration, flare data from VIIRS. Bonga's flare trend shows a marked reduction in positive flare rate observations from 2023 onwards (green bars).

The number of positive flare rate observations in 2021 was 643 versus a mere 50 such observations in 2023, a reduction of 92%. Conversely, the number of zero rate observations increased from 30 in 2021 to 117 in 2024, an increase of 290%. Because gas flaring for Bonga since 2023 has been sparse, flare variability increased while the contribution of routine flaring decreased (Table 7).

TABLE 7. Bonga oil production and gas flaring performance (2020–2026 year-to-date)

Bonga	2020	2021	2022	2023	2024	2025	2026
Oil rate (m^3/d)	18,682	16,706	14,776	19,840	19,588	19,241	13,905
Oil decline rate (%)	28.4%	10.6%	11.6%	–34.3%	1.3%	1.8%	27.7%
Flare rate (mln m^3/d)	0.196	0.331	0.156	0.060	0.050	0.049	0.134
Flare intensity (m^3/m^3)	10.51	19.79	10.57	3.04	2.57	2.56	9.62
Flare variability (m^3/m^3)	4.74	4.34	5.45	6.73	15.15	6.27	2.33
Routine Flaring (%)	64.7%	71.2%	70.0%	52.0%	48.1%	45.7%	71.7%

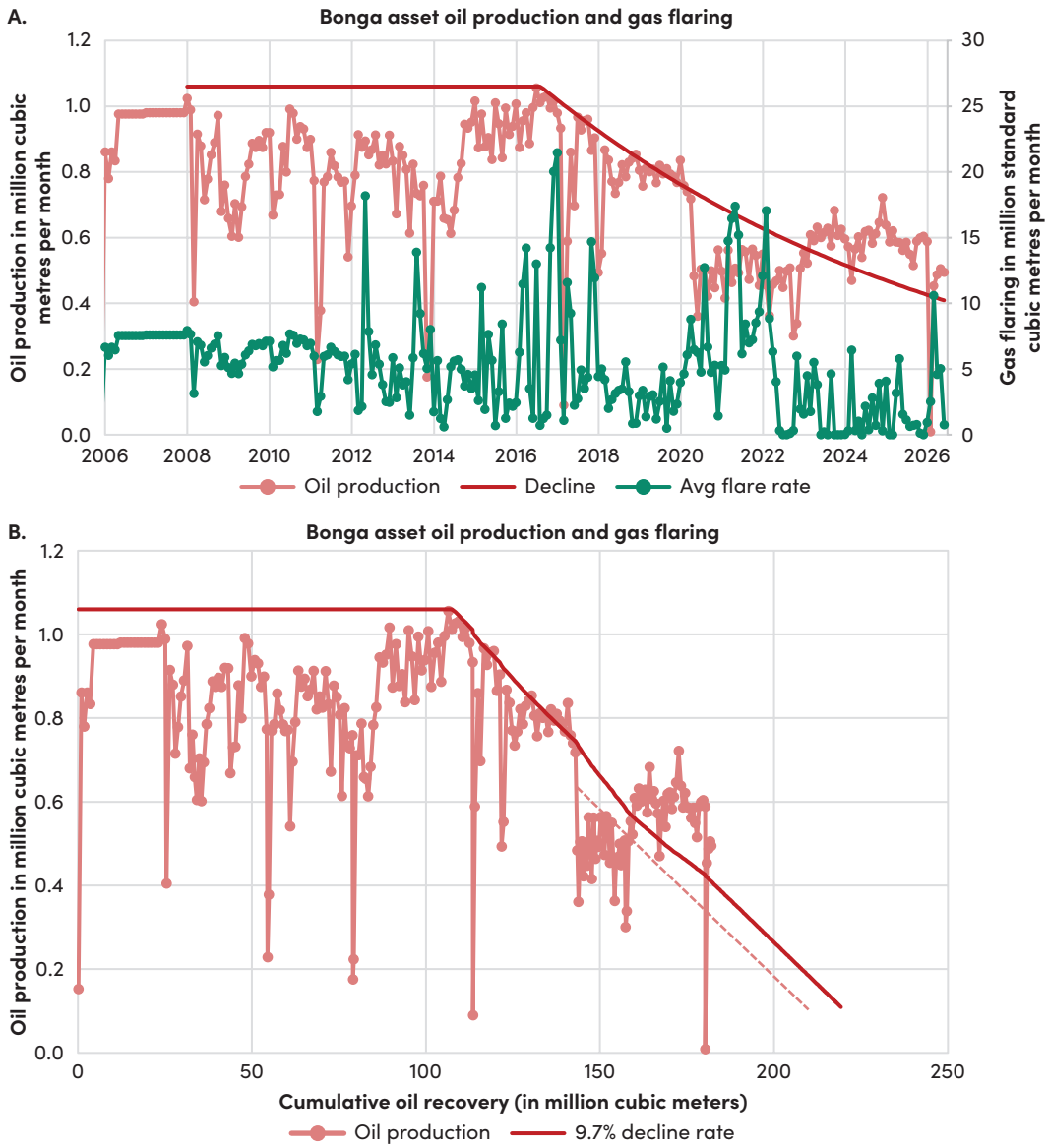
Shell reported in its sustainability report 2025 that since January 2025 it stopped routine flaring across all its operations.[55] Applying this study's routine flaring definition, routine flaring emissions from Bonga amounted to 7,716 tonnes (8.71 mln m^3) and 9,836 tonnes (11.08 mln m^3) for the years 2024 and 2025, respectively.

Bonga gas export constraints resulting from its riser integrity issues started late 2019. In the period that followed oil rates were curtailed and flaring increased until remediations were completed in July 2022. Several other gas compression and dehydration issues further contributed to Bonga's high flaring in this period. Since the remediations, Bonga's flaring significantly reduced while its oil

55 https://www.shell.com/sustainability/reporting-centre.html.

production increased. In 2023–2025 the field outperformed its previously established 9.7% oil decline trend. Bonga's flaring and oil production performance were less good from February to June 2026 and need to be watched closely to ascertain if the prior improvements can be sustained.

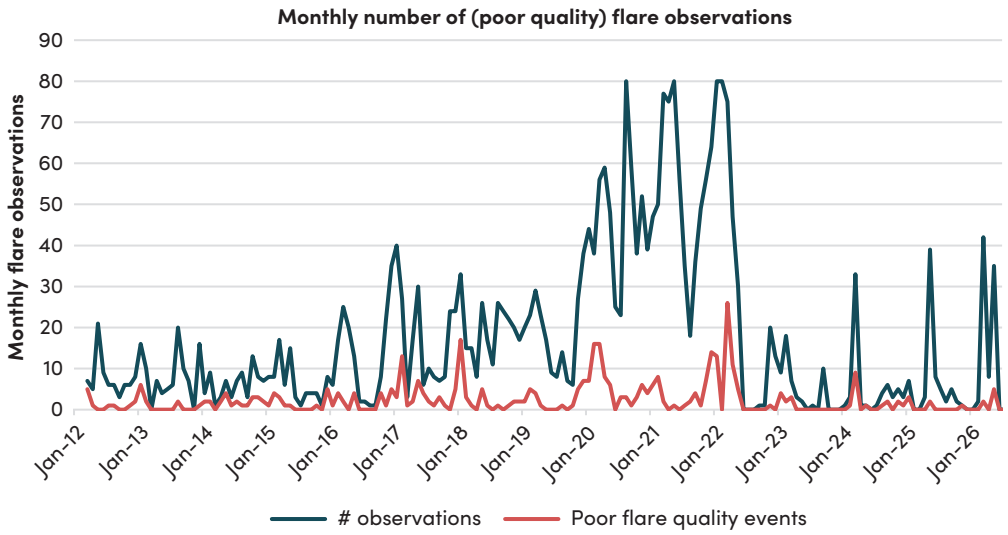
FIGURE 47. Bonga asset oil production, decline and flare rate



Notes: Author's illustration, flare data from VIIRS, production data from oil data from OPM study and NUPRC, https://www.nuprc.gov.ng/oil-production-status-report/. In August 2014 Bonga North West came on stream, resulting in increased oil production, but also started a period of more variable gas flaring performance.

Following the repair of the gas dehydration issue early in 2022 (about 6 months before the riser repair) a significant reduction in poor flaring events can be observed (Figure 48).

FIGURE 48. Bonga poor flare quality observations



Note: Author's illustration, flare data from VIIRS.

The resolution of aforementioned disputes and the frame work under the PIA has unlocked significant investments, with Shell investing USD 7 billion to date since late 2024.[56] The Shell Bonga consortium took a USD 5 billion FID on its operated Bonga North deepwater oil project in December 2024. Bonga North will be tied back to the existing Bonga FPSO, extending its economic life with first oil from Bonga North expected by 2030. It is targeting a peak production of 110,000 b/d from estimated recoverable reserves of 330 million bbl of oil equivalent (boe).

In addition, Presidential Approval for Bonga's USD 20 Billion Final Investment Decision (FID) on Bonga South West Aparo (BSWA) Deepwater Project was obtained on March 10, 2026. BSWA will be developed through a new separate FPSO. **The Bonga Southwest project will be the first FID on a Nigeria deepwater Production Sharing Contract asset since 2008**, re-establishing Nigeria as a premier deepwater investment destination. The fiscal package approved by President Tinubu includes an enhanced Production Tax Credit and resolution of the 2021 dispute settlement agreement, creating a competitive framework that balances national value with investor returns.[57]

Once FID is obtained, the BSWA project, operated by Shell, aims to create over 5,000 direct and indirect jobs, and deliver 150,000 barrels per day of crude oil and 140 million standard cubic feet per day of gas upon completion. The phased development has the potential to develop 1 billion boe of reserves. The Aparo gas field and the third-party-owned Bonga SW Field share a common geologic structure and are planned to be developed jointly. The structure lies in 4,300 feet (1,311 m) of water,

56 https://www.argusmedia.com/en/news-and-insights/latest-market-news/2779568-nigeria-sets-2027-deadline-for-fid-on-bonga-southwest.

57 https://nnpcgroup.com/insights/press-release-nnpc-secures-presidential-approval-for-20-billion-final-investment-decision-on-bonga-deepwater-project.

70 miles (113 km) off the coast of the western Niger Delta region. The proposed development plan involves subsea wells tied back to an FPSO vessel.

9. Conclusions

This paper has updated the flaring performance and related field performances of five global super-emitter flares located offshore Nigeria. The latest analysis complements EnergyCC's previous flare study with Oxford Policy Management Limited on the same assets by adding additional performance data in the period January 2023 to June 2026.

The study used VIIRS Night Fire (VNF) data from Earth Observation Group, Payne Institute for Public Policy, that provides ubiquitous and long-term (since 2012) global gas flare data for detailed diagnostics and assessments.

The outcome of the flare evaluation update provides a mixed picture. Compared to 2020–2022 period, the Bonga flare rate improved the most during 2023–2025 with 77% reduction in flaring, followed by Agbami (–57%). Gas flaring from Abo (–6%) and Usan (+8%) stayed more or less constant, while Yoho increased (+25%). With the exception of some flares in Mexico, the individual flare rates of Agbami, Yoho, Usan, and Abo, each exceed any flare in any of the OECD countries in 2024. This evidence indicates a substantial divergence between international operational standards and the actual gas flaring practices maintained by international oil companies (IOCs) within Nigeria.

The detailed analysis provided new insights on natural gas flaring, relevant for oil and gas stakeholders, regulators, investors, and revenue/tax authorities. With companies' publicized commitments to stop routine flaring there is a risk that these companies use loopholes to requalify routine flaring into non-routine flaring. Stringent flaring definitions and verification processes are recommended. Hence, a methodology was developed to distinguish routine flaring (i.e. flaring to produce) more clearly from non-routine flaring (i.e. flaring to safely stop production). This simple and transparent methodology is applicable for continuous flare measurements (metered gas flares) as well as intermittent measurements (satellite data). The calculated life-cycle routine flare percentages for the five Nigeria assets are: Bonga (52%), Agbami (61%), Yoho (71%), Usan (73%), Abo (74%). In the period 2023–2025, Bonga managed to reduce its routine flaring to 40.5%, at much reduced flare rates.

A conceptual gas flare life cycle model was also developed and tested. The assets analyzed show commonalities in their gas flaring lifecycle that show a distinct pattern in value loss (in USD) and energy loss (as percentage of crude energy produced) over time. Both parameters are critical for both the (fiscal) revenues that can be achieved, and for efficient energy utilization. The paper suggests that regulators should monitor flare rates (value loss) as well as flare intensity (energy efficiency) simultaneously and set (mandatory) performance standards for both.

The impact of natural gas flaring is substantial. The gas value loss from a single flare (Agbami) can be as high as USD 160 million per year, while the gas flaring energy loss can be as high as 35% of the energy content of the crude produced (Abo).

Natural gas flaring not only destroys the value of gas flared; gas flaring intensity (i.e. volume of gas flared divided by the oil volume produced) also shows a correlation with the rate of decline of oil production (average correlation factor 0.64). Notwithstanding the multifaceted interactions between gas flaring dynamics and oil production, as documented in this paper, that correlation is strong. When excessive flaring is an indicator for reservoirs being overproduced, accelerated oil production is more than offset by subsequent steeper oil decline rates, resulting in compromised oil ultimate recovery, and hence value loss, for the field. In 2025, the accelerated oil production decline from higher flaring intensity for the five offshore assets was 8.6%, exceeding an average field decline of 5%. The estimated oil value loss due to the additional 3.6% decline is USD 217 million (at USD 60/bbl oil price).

The methodology applied allows comparisons to be made on operational performance when operatorship is transferred. In the period December 2024 to September 2025 after Seplat took over operatorship for Yoho, the asset produced at significant lower flare rate (–45%) compared to the two previous years.

Reservoir management is critical to maximize asset value, optimize ultimate oil recovery and avoid routine gas flaring. Abo's high Gas to Oil Ratio (GOR) production puts it in a bind of a narrow production range to remain profitable and to avoid flaring. The paper suggests that further development of mature high GOR assets such as Abo should focus on producing more oil at much lower GOR, increasing gas reinjection capacity, or both.

Periods of fiscal and commercial uncertainty, such as doubts about license extensions, have also had a direct impact on the assets' flaring performance. Commercial and legal disputes cause hidden costs by accelerating production decline, increasing gas flaring, and reducing current and future taxable income. These costs have commonly been ignored.

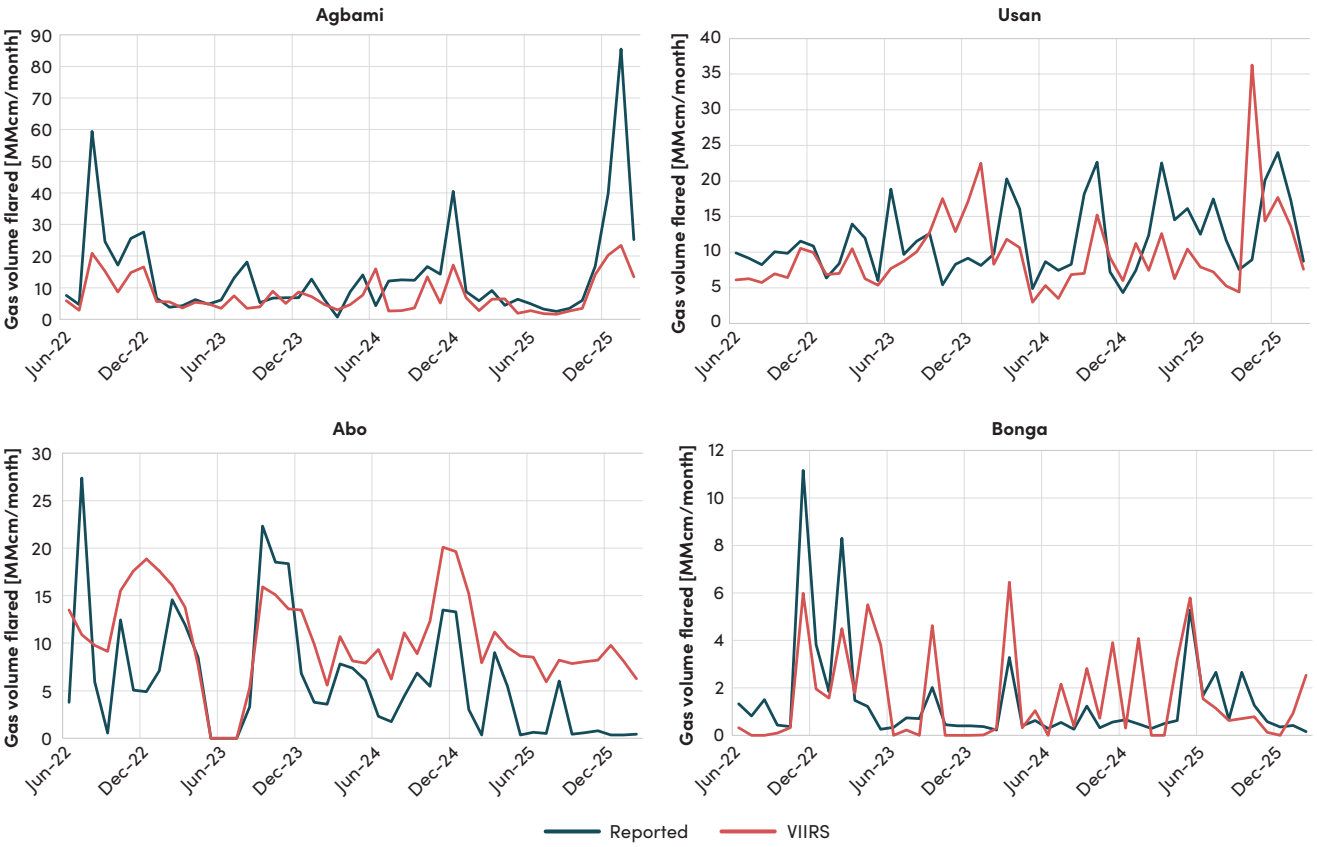
Fortunately, the resolution of the aforementioned disputes and the frame work under Nigeria's Petroleum Industry Act (PIA) that became operational in August 2022, have restored a more stable investment climate that has since unlocked significant investments.

Longer term developments for the five assets focus increasingly on the importance of gas monetization going forward. Commerciality of oil-to-gas redevelopment obviously benefits from maintaining sufficient gas resource volumes in the reservoir through reinjection instead of flaring throughout the production lifetime. By June 2026, the five assets combined have flared an estimated 11,870 million cubic meters of gas throughout their production life, valued at a potential USD 4.37 billion of gas sales, assuming LNG export at USD 10/MMBtu.

Appendix A. Comparison of VNF satellite flare rates with reported flare rates

Operators in Nigeria report gas production and utilization details on a monthly basis. Since July 2022, these data are published by NNPC as part of its monthly disclosures.[58] Not all assets are reported separately, but Agbami, Usan, Abo and Bonga are. Monthly reported gas data was not available for Yoho. A comparison was made of VNF satellite flare data with the reported flare data for the four offshore assets Figures A1a–d.

FIGURE A1. Comparison of VNF satellite data with reported flare data by month June-2022 to February 2026



Note: Author's illustration, flare data from VIIRS and NNPC reports; (a, top left) Agbami, (b, top right) Usan, (c bottom left) Abo, (d bottom right) Bonga.

From the flare data analysis, the following observations can be made:

- In aggregate, the VIIRS derived flare rate is 11.5% lower than the reported rate for all four assets combined during the period June 2022 to February 2026.

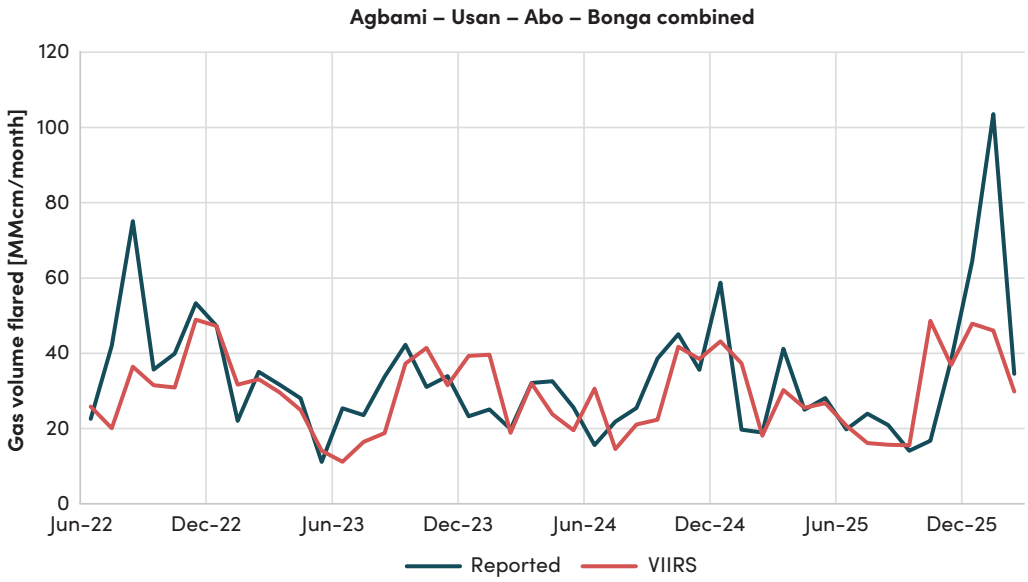
58 NNP reports monthly gas data by asset https://www.nnpcgroup.com/documents/.

- VIIRS tends to miss the (non-routine) high flare peaks while matching the (routine) base flare rate quite well. This is particularly obvious for Agbami.
- VIIRS provides a statistical sample of individual flaring observations. With increasing number of observations, the statistical scatter reduces.

Because VNF measurements occur only at night, they will miss flare events that are preferentially planned during daytime, such as the high flare rates that occur during facilities blow down in preparation of facility maintenance activities. Emergency flaring is also more likely during daytime when other non-routine activities are more likely to take place.

Figure A2 shows the profiles when flare observations for the four assets offshore assets are combined. This data shows that the VNF measurements trend the reported data quite well.

FIGURE A2. Comparison of VNF satellite data with reported flare data for the four assets combined, by month June-2022 to February 2026



Note: Author's illustration, flare data from VIIRS and NNPC reports.

Using a Dynamic Time Warping (DTW) method[59] that compares the trends in two time series that allows for errors in both y-value (flare rate) and x-value (time) dimensions, the Goodness of Fit (F) between the two curves is 94%, based on:

$$F = 1 - \frac{D_{avg}}{Max_{Rep} - Min_{Rep}} = 1 - \frac{5.50}{103.55 - 11.13} = 94.5\% \quad \text{(a1)}$$

59 In the analysis we are interested to determine how well the two data series with flare values compare. Because the interest is in the overall trend as opposed to specific flares values at specific points in time, the DTW method applies.

D_{avg} is the average absolute error per step, 5.5 million m³/month, calculated as the total Cumulative Absolute Distance: D = 285.81 divided by the optimal warping path length of L = 52 steps.

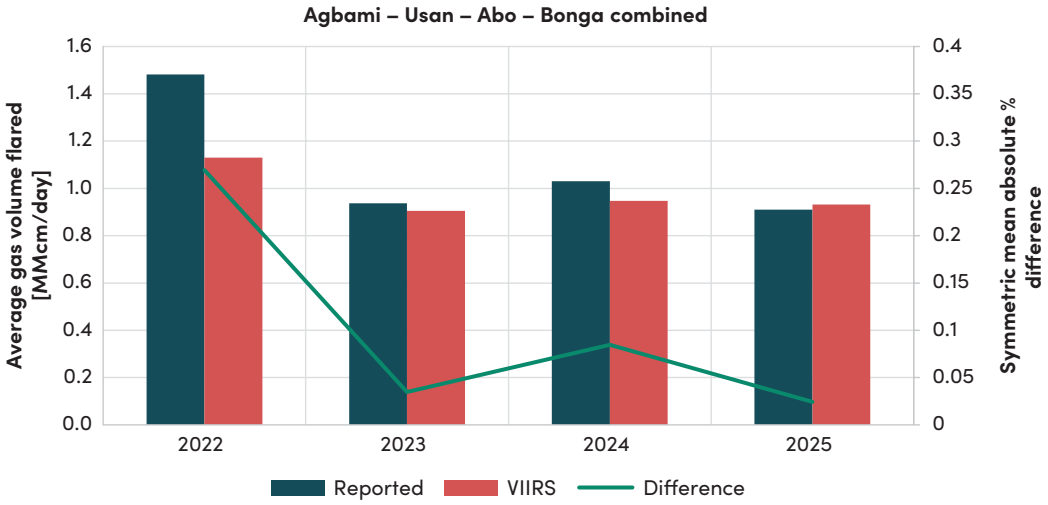
D is the total absolute vertical distance (flare rate-error) summed across the optimal alignment path.

L is the time adjusted path length. Because the algorithm flexes time (time-error) to pair delayed peaks and troughs, the path extends slightly past the raw series length of 45 months.

The Goodness of Fit outcome is influenced by the Agbami's reported strong peak in January 2026 that was not observed as strong in the VIIRS data. However, because both series spiked and then sharply fell simultaneously, the DTW algorithm preserved the trend. Minor Time Shifts (errors) occur around the period May 2023 to January 2024. The VNF series of measurements hits minor valleys and peaks 1 to 2 time units out of phase with the reported flare data series. DTW successfully corrected for this time delay, preventing it from artificially degrading the final goodness score.[60]

Time averaging the flare data from monthly to yearly intervals (i.e. increasing the statistical validity) shows the Goodness of Fit in another way (see Figure A3).

FIGURE A3. Comparison of VNF satellite data with reported flare data for the four assets combined, based on average daily flare rates per calendar year in the period June-2022 to December 2025



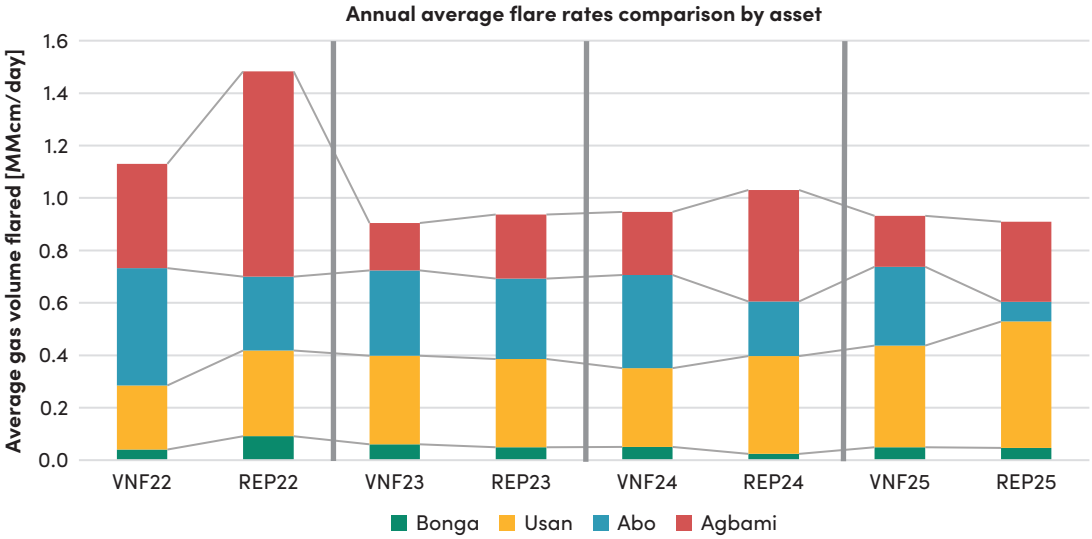
Notes: Author's illustration, flare data from VIIRS and NNPC reports. For 2022 average daily flare rates, only part year information was used (1 June to 31 December 2022). In this overview, the year 2026 is excluded as the statistical validity is low with only 2 months of data available to date. The relative difference between reported and VIIRS flare rates (green curve) is determined as the Symmetric Mean Absolute Percentage Error (SMAPE).[61]

60 If the spike in the reported flare data on January 2026 is ignored, the Goodness of Fit F = 93%. Although D drops from 285.81 to 228.31, with a new warping path Length L = 51, (Davg drops from 5.5 to 4.48 million m³/month), the denominator drops from 92.42 to 63.97 with a new reported flare maximum of 75.10.

61 https://towardsdatascience.com/choosing-the-correct-error-metric-mape-vs-smape-5328dec53fac/.

Breaking down the annual average flare rates by asset reveals some differences, Figure A4. The reason why VNF may under-estimate reported data due to daytime flare peaks was described above. Among the four offshore assets, Agbami has the highest monthly flare rate correlation (R = 0.82), but misses the significant flaring peaks (Figure A1a).

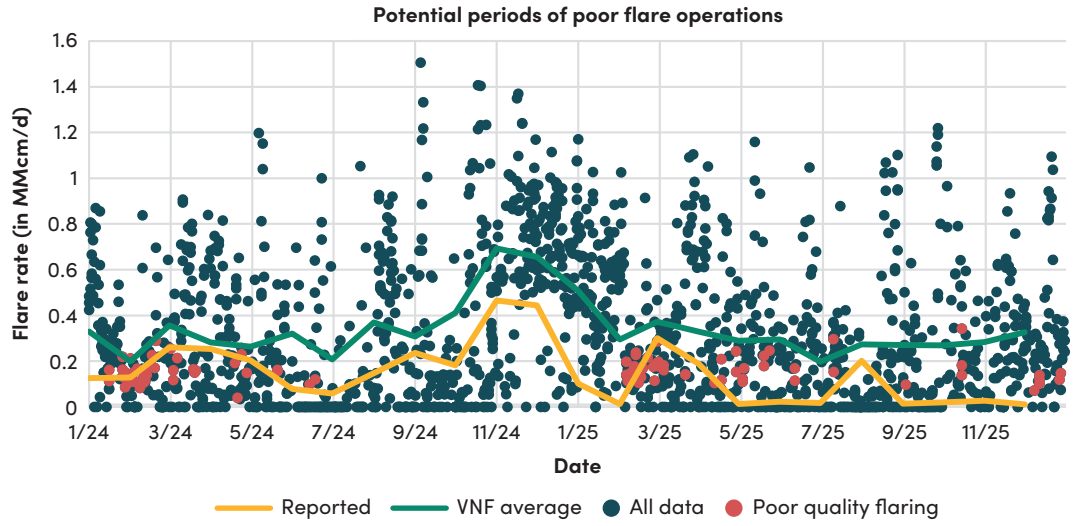
FIGURE A4. Comparison of VNF satellite data with reported flaring for the individual assets, based on average daily flare rates per calendar year from June 2022 to December 2025



Notes: Author's illustration, flare data from VIIRS and NNPC reports. For 2022 average daily flare rates, only part year information was used (1 June to 31 December 2022). In this overview, the year 2026 is excluded as the statistical validity is low with only 2 months of data available to date. VNF22 denotes average satellite measurements in 2022; REP25 denotes reported average flare data in 2025.

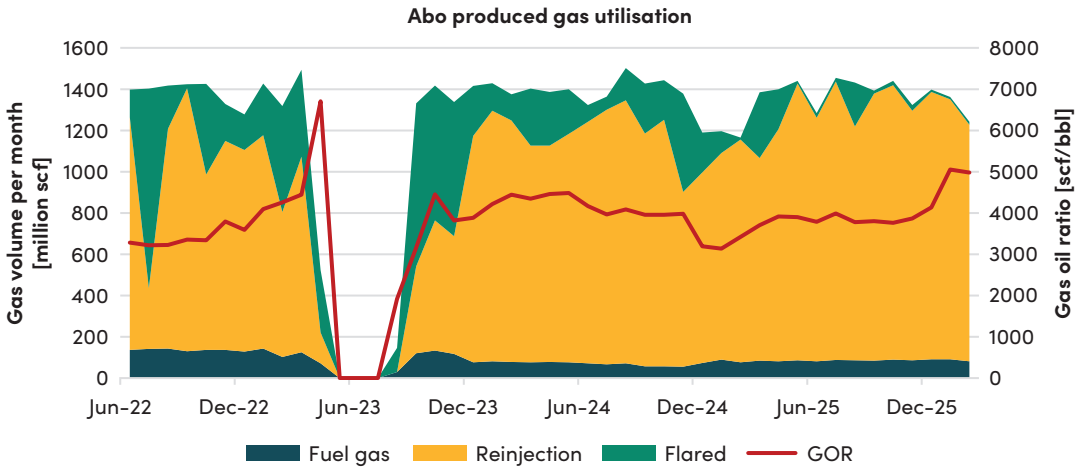
Abo's performance is interesting because it is the only asset for which VNF flare rates exceed reported data each year. Figure A5 shows Abo's monthly reported and VNF data (Figure A1c) superimposed with individual VIIRS measurements for the period 2024–2025. With the exception of the period November 2024 to January 2025, the VIIRS measurements remain stable throughout the period; in contrast, reported flare data show a significant reduction in 2025 compared to 2024, in line with ENI's zero routine flaring target taking effect in 2025. Further analysis of reported data provides a detailed breakdown of Abo's produced gas balance based on reported data (Figure A6). The reported data shows that reservoir performance (gas produced and gas oil ratio, GOR) did not improve during the period (see Section 8.4). However, fuel gas declined while reinjection volumes increased. As ENI mentioned that flare data is metered, it would be interesting to compare daily metered and VNF flare rates.

FIGURE A5. Comparison of Abo individual VNF satellite data with monthly reported and monthly VNF average flare data for 2024 and 2025



Note: Author's illustration, flare data from VIIRS and NNPC reports.

FIGURE A6. Reported breakdown of Abo produced gas and GOR based on monthly reports



Note: Author's illustration, Abo gas data from NNPC reports.

Appendix B. Glossary and acronyms

The following is a glossary explaining some of the technical terms in the context of this paper, followed by a list of acronyms.

Reservoir and processed hydrocarbon types

Natural gas:	a hydrocarbon-based energy resource, consisting primarily of methane with percentages of ethane, propane, butane, and other gases such as nitrogen, carbon dioxide, and potentially hydrogen sulfide (H_2S). Natural gas is stored and transported in pressurized gaseous form or as a super-cooled liquid, LNG.
Upstream natural gas:	a 'wet' natural gas that is unprocessed and often contains Natural Gas Liquids (NGLs) vapours. Wet gas has a higher energy density (1,242 Btu/scf or 46.3 MJ/m^3) than processed (domestic) natural gas, (1,000 Btu/scf or 37.3 MJ/m^3). Upstream natural gas also contains contaminants and is more difficult to burn cleanly in a gas flare.
Liquefied Natural Gas (LNG):	primarily methane, CH_4 (sometimes with some ethane C_2H_6) that has been cooled down to a liquid state at approximately –162°C (–260°F) at atmospheric pressure. With a high volumetric density (422 to 455 kg/m^3) and low pressure compared to compressed methane (0.68 kg/m^3 at atmospheric pressure, 79 kg/m^3 at 100 bar, @15°C), LNG is more economic to transport and store natural gas across very large distances than pipelines.
Natural Gas Liquids (NGLs):	are hydrocarbons of the alkanes group (C_nH_{2n+2}) heavier than methane that occur in upstream wet natural gas. They exist as gases or vapours under reservoir conditions, but easily condense into a liquid state when cooled or moderately pressurized at the surface. NGLs are particularly valuable as petrochemical feedstock or as fuel (e.g. LPG).
Liquefied Petroleum Gas (LPG):	is a flammable mixture of hydrocarbon gases—predominantly propane (C_3H_8), butane (C_4H_{10}), or a blend of both—that is liquefied under moderate pressure to facilitate dense storage, handling, and transport. LPG is not a primary fossil fuel but a secondary by-product generated from natural gas processing and crude oil refining. It is mainly used for heating, transportation and as industrial feedstock.

Crude oil:	(often referred to simply as petroleum) is a naturally occurring, unrefined liquid fossil fuel composed primarily of hydrocarbons and other organic compounds. Found in deep underground geological formations, it is the raw material that is extracted and subsequently processed at petroleum refineries to manufacture gasoline, diesel, jet fuel, heating oil, and various petrochemical feedstocks.
Condensates:	Ultra-light, low-density liquid hydrocarbons that exist as a gas when trapped deep underground under reservoir pressures and temperatures, but condense into a liquid phase at the surface due to pressure and temperature drops. Chemically and physically, condensates sit in the narrow geological sweet spot directly between light sweet crude oil and raw natural gas liquids (NGLs).
Associated gas:	Associated gas is the combination of solution gas and free gas produced together with the oil. Production of large amounts of free gas by producing oil wells has negative consequences on production (flaring) and oil ultimate recovery.
Solution gas:	(also referred to as dissolved gas) is natural gas that is dissolved completely within liquid crude oil under the high pressure and temperature conditions of a subsurface reservoir.
Free gas:	exists as a separate layer of natural gas at the top of the reservoir (crest) separated by an oil-gas contact.
Non-associated gas:	(also referred to as unassociated gas or dry gas) is natural gas that is found as free gas in a subsurface reservoir that contains little to no liquid crude oil. It carries minimal volumes of heavier, liquefiable natural gas liquids (NGLs).

Properties of hydrocarbons

Bubble point:	is the exact thermodynamic state—at a given pressure and temperature—where the very first bubble of gas breaks out of solution from a liquid hydrocarbon mixture.
GOR:	Gas-to-Oil ratio is the proportion of gas to oil either in solution (solution GOR) or during production (producing GOR) that can include a component of free gas. Common units for GOR are gas/oil [m^3/m^3] and [scf/bbl] (1 m^3/m^3 = 5.615 scf/bbl).
LGR:	Liquid-to-Gas ratio is the proportion of NGLs to gas either in solution (solution LGR) or during production (producing LGL) that can include a component of free gas. Common units for LGR are liquid/gas [m^3/m^3] and [bbl/scf] (1 m^3/m^3 = 0.1781 bbl/scf).

Buoyancy:	When one fluid is placed within another fluid, buoyancy is the net vertical force that drives the separation of the two fluids based on their density differences.
(Oil) Viscosity:	is a physical property that measures a crude oil's internal resistance to flow, i.e. it describes how "thick" or "sticky" the oil is. The oil viscosity increases when reservoir pressure declines and gas comes out of solution as free reservoir gas. (note that also gas has viscosity that is much lower than oil, hence gas mobility in a reservoir is much higher).
Watercut:	is the water production rate divided by gross rate, i.e. water/(oil+water) rates.

Reservoir design and properties

Field:	in oil and gas development, is a geographically defined area of land or sea floor that sits directly above one or more underground hydrocarbon reservoirs sharing a common geological structure.
Reservoir:	in the oil and gas industry, is a subsurface pool of hydrocarbons contained within porous and permeable rock formations, trapped beneath an impermeable layer of cap rock, at elevated temperatures and pressures.
Oil rim:	is a relatively thin, narrow horizontal layer of liquid crude oil that is sandwiched between an overlying primary gas cap and a underlying water aquifer within a single subsurface reservoir structure.
Aquifer:	in the context of an oil and gas reservoir is a subsurface layer of water-bearing rock located directly beneath or adjacent to the hydrocarbon accumulation. Aquifers can be important in reservoir production processes as they provide pressure support to deliver crude oil towards producing wells (aquifer drive).
Gas Cap:	is a distinct accumulation of free natural gas that sits directly above the oil zone within a subsurface reservoir. It forms because natural gas is less dense than crude oil and water, its buoyancy causing it to naturally migrate to the highest structural point of the reservoir trap during geological formation (primary gas cap) or due to pressure depletion below bubble point during production (secondary gas cap).

Reservoir drive:	is the combination of fluid dynamics that provides energy for oil to flow to producing wells and to lift reservoir fluids to surface. Reservoir drive methods include depletion drive (oil expansion as reservoir pressure declines), aquifer drive (pressure support from an aquifer connected to the oil reservoir), gas cap drive (if a gas resource overlays and is in pressure communication with an oil reservoir) and energy support from secondary development options such as gas injection, water injection, or both.
Gas reinjection:	is the process of compressing produced natural gas and pumping it back down into a subsurface reservoir for disposal or storage. If the reinjection reservoir is the same as the producing reservoir, the reinjected gas supports the oil recovery process.
Gas blowdown:	Gas blowdown is the final phase of an oil field production cycle, when the recovery focus changes from oil to gas production to extract the remaining value from the field by depressurizing the reservoir.
STOIIP:	(Stock Tank Oil Initially In Place) is the total amount of crude oil volume contained in a hydrocarbon reservoir when evaluated at standard conditions 15°C (60°F), 1.103 bara (14.73 psia). As a consequence of shrinkage (gas liberation and thermal contraction), the volume of crude oil under reservoir conditions is significantly larger than its volume under standard surface conditions.
GIIP:	(Gas Initially In Place) is the total amount of gas volume contained in a hydrocarbon reservoir (as free gas and/or solution gas) when evaluated at standard conditions.
Ultimate Recovery (UR):	is the total amount of oil and gas that can be (economically) extracted from a reservoir, evaluated at standard conditions.
Reserves:	represent the remaining volume of crude oil and natural gas that currently remains in a reservoir and can be legally, technically, and economically extracted from the current date forward.
Oil Recovery Factor (RF):	is the oil ultimate recovery divided by the STOIIP.
Gas Recovery Factor (RF):	is the gas ultimate recovery divided by the GIIP.

Oil and gas development

Asset:	in the oil and gas industry, is any physical property, facility, or resource that a company owns, operates, or holds a financial stake in to extract, process, and transport hydrocarbons. It includes physical infrastructure (such as process facilities and pipelines) as well as the geological resource (field).
International Oil Company (IOC):	is a large, publicly traded, investor-owned oil and gas firm that operates across multiple countries and encompasses the entire petroleum supply chain, from exploration and production to refining and retail distribution.
Energy Majors:	The seven largest IOCs are known as the supermajors: ExxonMobil, Shell, Chevron, TotalEnergies, BP, ConocoPhillips, and ENI.
Upstream:	encompasses all activities related to locating, accessing, and extracting raw crude oil and natural gas from subsurface geological reservoirs. It is the beginning of the oil and gas supply chain.
Midstream:	serves as the logistical link between the (often remote) extraction sites (upstream) and the final processing hubs or industrial consumers (downstream). Its primary mandate is transporting and storing bulk volumes of hydrocarbons safely over long distances. It may also involve oil and gas processing activities (referred to as conditioning, such as gas dehydration) to ensure that the physical properties of the hydrocarbons meet infrastructure design specifications.
Downstream:	represents the final phase of the oil and gas supply chain. It focuses on turning raw, unrefined hydrocarbons into finished, consumer-ready products, product distribution and executing wholesale and retail sales. For LNG, liquefaction and shipping are generally part of the midstream. The destination storage and regasification sit at the boundary point between midstream and downstream (and can be classified either way).
Operated assets:	In the oil and gas industry, operated assets are oil and gas fields, production platforms, facilities, or pipelines where a specific company (designated as the operator) holds the primary legal and day-to-day responsibility for managing all physical operations, engineering tasks, and safety protocols.

Non-operated assets:	The company owns a financial stake (equity) and receives a share of the production and/or revenue, but has no direct say in daily field management or mechanical operations, i.e. the asset is 'operated-by-others'. Non-operating partners influence and exert control over their non-operated assets through a structured framework of legal agreements, financial approval processes, and collaborative governance committees.
Onshore:	refers to oil and gas exploration, drilling, and production operations that take place entirely on dry land.
Offshore:	refers to operations conducted at sea, ranging from shallow coastal waters to ultra-deep oceanic basins miles away from the coastline. Infrastructure relies on specialized marine structures such as fixed steel platforms, jack-up rigs, drillships, subsea wellhead and process systems, and/or floating vessels like FPSOs and FLNGs anchored to the ocean floor.
Deepwater:	refers to offshore exploration, drilling, and production activities conducted at significant water depths where conventional, bottom-supported fixed platforms are no longer technically or economically viable. Water depths exceed conventional diving limits (i.e. beyond 200–300 m). Ultra deepwater exceeds 1,500 m water depth, such as Shell's Stones field at 2,896 m water depth, the world's deepest operating oil and gas production project.
FPSO:	Floating Production, Storage and Offloading facility is a specialized, offshore oil and gas production facility designed on the hull of a ship or as a barge. FPSOs are deployed directly over deepwater oil fields to process, store, and transfer hydrocarbons instead of relying on fixed steel platforms or long undersea pipelines.
FLNG:	Floating Liquefied Natural Gas facility is a very large floating vessel that houses a complete natural gas liquefaction plant directly above an offshore gas field. FLNG technology enables operators to extract, process, liquefy, store, and offload natural gas entirely at sea, eliminating the need for long undersea pipelines, near-shore processing hubs, or land-based LNG terminals. See also Liquefied Natural Gas (LNG).
LNG Train:	is an independent, self-contained processing unit within a liquefied natural gas plant that purifies and deep-freezes raw natural gas into its liquid state.

Well:	(or wellbore) is a long, narrow hole drilled deep into the earth's subsurface to access, evaluate, and extract hydrocarbons from underground reservoirs. Oil and gas wells are complex and highly engineered structures with controls, sensors and other equipment ('jewelry') to execute their function. The longest oil and gas well is 15,240 m (Upper Zakum ERD) and the deepest 10,683 m below seabed plus 1,259 m water depth (Tiber well).
Recompletion:	(in well engineering) is the mechanical process of altering an existing wellbore to change the specific subsurface reservoir zone from which it produces hydrocarbons. It involves physically isolating the old, depleted production zone and opening up a completely different, previously untapped reservoir interval higher up or lower down within the same well.
Sidetrack:	(in well engineering) is a secondary wellbore drilled away from an existing primary wellbore. It involves cutting through the steel casing of the original well and drilling a new hole at an angle to bypass a problem or target a completely new section of the reservoir.
Choke:	(in well engineering) is a specialized mechanical valve used to restrict, control, and regulate the flow rate and pressure of fluids (oil, gas, and water) emerging from a wellbore. It is the primary restriction device that acts as a gatekeeper, creating backpressure on the reservoir to prevent the well from producing too quickly and damaging downhole equipment or overloading surface facilities.
(Export) riser:	In offshore oil and gas developments, an export riser is a specialized, high-pressure pipeline that connects a surface offshore production facility to the seafloor infrastructure to transport processed hydrocarbons out of the field.
Topsides:	In the offshore oil and gas industry, the topsides (or topside superstructure) refer to the upper portion of an offshore production platform or floating vessel that sits entirely above the water's surface. It houses the physical processing equipment, crew living quarters, and safety systems. The topsides sit mounted on top of a supporting structure, such as the steel legs of a fixed jacket platform or the floating hull of an FPSO or FLNG vessel.
Trip:	in context of oil and gas processing facilities, refers to an automated, rapid safety shutdown of a system or piece of equipment.

Debottlenecking:	is the engineering process of identifying, modifying, or replacing specific restrictive components within a production system to increase the facility's overall processing capacity and efficiency.
Derating:	is the intentional reduction of an equipment's maximum operating limits to extend its operational lifespan under suboptimal conditions.
Decline rate:	is the natural, progressive decrease in the production rate of hydrocarbons from a well, a field, or an entire geographical basin over time. Because underground reservoir pressure depletes as oil and gas are extracted, the rate of flow inevitably slows down. This metric is expressed as a percentage decrease per year. Petroleum engineers model this behavior using Decline Curve Analysis (DCA).

Oil and gas emissions

Gas flaring:	The disposal of unwanted natural gas by burning, occurs mostly when natural gas (methane) is produced as a by-product of oil extraction. Flaring may occur for a variety of technical, economic, or safety reasons.
Routine flaring:	The continuous burning of produced gas that occurs when oil and gas production continues even though equipment capacity is unavailable or insufficient to process the all produced gas ("flaring to produce"). Routine flaring occurs intentionally, e.g. when a producer deems it uneconomic to capture and process the gas for use, reinjection, or sale.
Non-routine flaring:	The incidental and temporary burning of produced gas that occurs when production in an oil and gas facility is brought to a (sudden) process stop and the system needs to depressurized for safety reasons ("flaring to safely stop production").
Safety flaring:	See non-routine flaring.
Super-emitter gas flare:	a very large natural gas flare in terms of rate, making it one of the 300 largest global gas flares (top 3%).
Flare Intensity:	The amount of gas flared per volume of oil produced, expressed in the following units: flare gas/oil [m^3/m^3] and [scf/bbl] (1 m^3/m^3 = 5.615 scf/bbl (note similarities with GOR). Longer duration equipment failures and assets that are not repaired (such as e.g. flash gas compressors) show as continuous (i.e. 'routine') flaring and are identified by high flare intensity.

Flare Variability:	is defined as the maximum observed flare rate in a month divided by the monthly average flare rate. The lowest flare variability value of 1 indicates a constant flare rate throughout the month. Flare variability is indicative for the severity and frequency of short duration production upsets. Therefore, this measure is particularly sensitive to identify process trips and reactive emergency shutdowns, that are related to overall topsides process stability.
Flare quality:	Reflects the quality of the flare combustion quality, expressed in the gas destruction effectiveness, with a (EPA) standard of 98%, i.e. at least 98% of the natural gas that is flared should be converted into carbon dioxide (CO_2)
Venting:	The direct release of natural gas into the atmosphere, creating methane and other emissions that are harder to detect than gas flaring. Venting includes intentional emissions through a (chimney)stack as well as other fugitive emissions, including leaks and releases during maintenance activities, that do not involve combustion.
Fugitive emissions:	from oil and gas systems include all GHG emissions (intentionally or accidental) except contributions from fuel combustion for the production of useful heat or energy (IPCC definition)
Greenhouse Gas (GHG):	is any gaseous compound in the atmosphere that is capable of absorbing and emitting infrared radiation. This process traps thermal energy within the Earth's atmospheric system, driving the warming phenomenon known as the greenhouse effect. While greenhouse gases are necessary to maintain a habitable temperature on Earth, anthropogenically induced increases in their concentrations are the primary drivers of modern global climate change.
Sustainability reporting:	is the practice by which organizations publicly disclose their economic, environmental, social, and governance (ESG) impacts. It serves as a structured communication tool that allows companies to demonstrate accountability to investors, regulators, consumers, and civil society regarding how their operations affect—and are affected by—sustainability issues. Rather than focusing solely on financial performance, sustainability reporting provides a comprehensive overview of a company's long-term risks, operational resilience, and non-financial metrics.

Other acronyms

bbl	barrel, unit of volume, 1 bbl = 0.158987 m^3.
Bcf	billion cubic feet, 10^9 ft^3, 1 Bcf = 28.32 million m^3.
Bcm	billion cubic meters.
bpd	barrel per day (also b/d).
boe	barrels of oil equivalent, the total energy content of oil and gas expressed in the equivalent amount of barrels of oil.
Btu	Brtitish Termal Unit, unit of energy, 1,000 BTU = 1.055×10^6 Joules (MJ) = 0.29307 kilowatt-hours (kWh). 1 MMBtu = 10^6 Btu.
BW	Bergensen Worldwide, a merger of Norwegian company Bergensen d.y. ASA and Honk Kong-based World-Wide Shipping.
CGD	Center for Global Development.
DCA	Decline curve analysis (see 'decline rate')
DNV	Det Norske Veritas, an international maritime classification society and independent assurance and risk management company, headquartered in Norway.
EGP	Escravos Gas Plant.
EGTL	Escravos Gas-to-Liquids facility.
EPCIC	Engineering, Procurement, Construction, Installation, and Commissioning contractual framework.
ESG	Environmental, Social, and Governance.
FEED	Front End Engineering and Design is the project development phase preceding detailed design and construction.
FID	Final Investment Decision, is the definitive point in a project's lifecycle where the energy company formally approves the full capital expenditure required to move a project into the construction and execution phase. Signing the FID transforms a project from an abstract engineering concept into a fully funded, legally binding commercial asset.
FSO	Floating Storage and Offloading vessel (see also FPSO); an FSO has no oil and gas processing facilities on board.
GTL plant	is an advanced gas refinery complex that chemically converts natural gas into high-value, ultra-clean liquid hydrocarbons—such as synthetic diesel, kerosene, jet fuel, naphtha, and lubricants. By altering the molecular structure of methane, a GTL plant transforms a difficult-to-transport gas into stable liquids that can be stored, piped, and sold using standard crude oil infrastructure.

GTC	Gas Turbine Compressor (to compress natural gas for processing, transportation, or re-injection).
HSE	Health, Safety, and Environment refers to a core corporate department or function, regulatory framework, and operational discipline dedicated to protecting the physical well-being of the workforce, ensuring the integrity of industrial assets, and minimizing the environmental footprint of operations.
IWC	Intelligent Well Completion (also known as a smart well completion), is an advanced subsurface engineering system that allows oil and gas operators to monitor, analyze, and optimize production from individual reservoir zones in real-time without performing physical well interventions. By embedding permanent downhole sensors and remotely adjustable flow-control valves directly into the wellbore completion assembly, intelligent wells allow engineers to manage a well's performance remotely.
LP	Low Pressure.
mln	million.
MMscf/d	million standard cubic feet per day, 1 MMscm/d = 35.3147 MMscf/d.
MMscm/d	million standard cubic meters per day.
Mtpa	million tonnes per annum; 1 tonne (metric ton) = 1,000 kg.
NLNG	Nigeria LNG Limited, Incorporated in May 1989, it is a major midstream joint-venture energy corporation and the operator of a six-train natural gas liquefaction complex located on Bonny Island, Nigeria.
NNPC	Nigerian National Petroleum Company Limited (formerly the Nigerian National Petroleum Corporation). With an asset base exceeding USD 150 billion, it is the state-owned NOC of Nigeria and the largest integrated energy corporation in Africa.
NOC	National Oil Company.
NUPRC	Nigerian Upstream Petroleum Regulatory Commission.
OPEC	Organization of the Petroleum Exporting Countries.
OML	Oil Mining Lease granted by NUPRC once a commercial discovery is made on an Oil Prospecting License (OPL).
OPL	Oxford Policy Management Limited.
PIA	Nigeria's Petroleum Industry Act that became operational in August 2022.
PSC	Production Sharing Contract, is a formal, legally binding contract between a host country's national government and an (international) oil company or consortium. Under a PSC, the IOC takes on all the initial financial and operational risks of

	exploration and development in exchange for a share of the actual oil and gas produced if a commercial discovery is made.
SEC	Securities and Exchange Commission.
SPM	Single Point Mooring buoy, is an offshore floating loading and offloading terminal anchored to the seabed. SPMs are deployed several kilometers out at sea to allow seagoing vessels—such as Very Large Crude Carriers (VLCCs)—to safely transfer fluids without requiring deepwater ports, near-shore berths, or canal dredging.
scf	standard cubic foot = 0.3048^3 m^3 = 0.028317 m^3 and 1 m^3 = 35.3147 scf.
TAM	Turnaround Maintenance shutdown is a scheduled, large-scale event when an entire processing facility or asset is temporarily taken completely offline. Production is halted for a few weeks to several months so teams can safely execute extensive overhauls, regulatory inspections, and physical upgrades that are impossible to conduct while the asset is live.
Tcf	Trillion cubic feet, 10^9 ft^3, 1 Tcf = 28.32 billion m^3 (Bcm).
tn	tonne, metric ton, 1 tonne (tn) = 1,000 kilogram (kg)
x-month TMA	Trailing Moving Average (aka backward-looking or historical moving average) is a statistical calculation used to analyze data points by creating a series of averages from a specified subset of the recent past (e.g. x-monhs).
USD	United States Dollar currency.
VIIRS	a highly advanced scanning radiometer sensor deployed on several next-generation polar-orbiting environmental and weather satellites, including the joint NASA/NOAA Suomi NPP, NOAA-20, and NOAA-21 platforms.
VNF	VIIRS Nightfire is a widely recognized global satellite tracking dataset and algorithmic model. It was developed by the Earth Observation Group (EOG) to identify and measure sub-pixel thermal radiation sources at night.
ZRF30	Zero Routine Flaring by 2030 initiative was introduced in 2015 by the World Bank and the United Nations Secretary-General. It is a global climate and energy policy framework designed to eliminate the oil and gas industry practice of routinely burning associated natural gas during oil extraction.