Responsible Change:

How Governments Can Address Environmental, Social and Governance Challenges When Petroleum Assets Change Hands

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Contents

Cover image: Photo by Nikkytok

Key messages

- As the world moves toward a future beyond oil and gas, petroleum assets will change hands, with different kinds of companies replacing others.
- Since 2014, around USD 88 billion in assets have moved from publicly listed to private companies. The roles of sub-Saharan African and Latin American companies in their home countries have expanded.
- Globally, the role of national oil companies (NOCs) is growing. NOCs have acquired around $24 billion in assets from non-NOCs since 2014.
- The growing role of private and local companies and NOCs potentially gives producer countries greater control over their petroleum sectors, including the pace of an eventual phaseout.
- However, these companies often have less capacity and fewer transparency, environmental, social and governance commitments than publicly listed international companies. This increases the risk that these companies' operations will negatively impact the environment and communities, and that they will be unable to pay for decommissioning when production ends.
- Many assets that sub-Saharan African and Latin American NOCs have acquired appear vulnerable to energy transition risks.
- Governments should exercise approval rights over asset transfers to ensure buyers have requisite capacity to operate with high standards. They should ensure transparency to allow host communities and the public to better understand transfer impacts and how the government and/or companies will manage them, and strengthen regulations to address key issues arising from transfers including emissions management and reporting, and decommissioning funding.
- Governments should require NOCs to make adequate disclosures about their acquisitions to ensure NOCs manage risks to the public purse.

Summary

As the world journeys towards a future beyond oil and gas, oil and gas assets will continue to change hands, with different kinds of companies filling the gap left behind by others.

There is growing concern that, as international oil companies (IOCs) face pressure to reduce emissions, they are selling upstream petroleum assets, in part, to shift emissions off their books and ostensibly achieve their decarbonization goals.[1] On balance and at a global level, assets are moving from publicly listed to private companies and from companies with higher environmental commitments to those with weaker commitments.[2] The result, according to some evidence, is that these sales do not simply transfer emissions to new parties but may increase them.[3]

At the same time, some national oil companies (NOCs) seek to acquire assets left behind by the departure of IOCs to avoid production decline and ensure domestic energy supply.[4]

This briefing shows how asset transfer trends may differ by region and country, and therefore present different risks and raise different policy considerations for producer country governments. It focuses on the Global South countries and regions in which the Natural Resource Governance Institute (NRGI) works.

NRGI analyzed upstream petroleum asset transfers from 2014 to the first half of 2023 (H1 2023), using Rystad data to identify trends globally, at the sub-Saharan African and Latin American regional level, and in NRGI's countries of focus.[5]

This analysis shows that petroleum assets worldwide have moved primarily from publicly listed to private companies during the period studied. Since the start of 2014, around USD 88 billion in assets have moved from publicly listed to private companies. Both sub-Saharan Africa and Latin America have seen net divestment by publicly listed companies. In sub-Saharan Africa, there has been a transfer of around $23 billion in assets from publicly listed to private companies since the start of 2014, while in Latin America, around $11 billion in assets has moved from publicly listed to private companies.

1 See, e.g., United States House of Representatives, Committee on Oversight and Reform, *Memorandum Re: Investigation of Fossil Fuel Industry Disinformation* (9 December 2022), www.oversightdemocrats.house.gov/sites/democrats.oversight.house.gov/files/2022-12-09.COR_Supplemental_Memo-Fossil_Fuel_Industry_Disinformation.pdf.

2 Gabriel Malek, Andrew Baxter, Dominic Watson and Andrew Howell, *Transferred Emissions: How Risks in Oil and Gas M&A Could Hamper the Energy Transition* (Environmental Defense Fund, 2022), www.business.edf.org/insights/transferred-emissions-risks-in-oil-gas-ma-could-hamper-the-energy-transition/.

3 See Jack Arnold, Martin Lockman, Perrine Toledano, Martin Deitrich Brauch, Shraman Sen and Michael Burger, *Transferred Emissions Are Still Emissions: Why Fossil Fuel Asset Sales Need Enhanced Transparency and Carbon Accounting* (Columbia Center on Sustainable Investment, 2023), 42-50, www.scholarship.law.columbia.edu/sustainable_investment/14/. Examining a sample of sold assets, the authors found that post-sale emissions intensities for these assets tended to be higher. The authors also reviewed environmental and non-environmental violation records of buyers and sellers involved in the transactions in the sample and found buyers had a higher number of violations per billion barrels of oil equivalent produced than sellers. The authors acknowledged several limitations to their analysis.

4 See Andrea Furnaro and David Manley, *Facing the Future: What National Oil Companies Say About the Energy Transition* (NRGI, November 2023), 20-21, www.resourcegovernance.org/publications/facing-future-what-national-oil-companies-say-about-energy-transition.

5 See Rystad Energy, www.rystadenergy.com/.

Sub-Saharan African and Latin American companies have been playing an increasing role in their home countries (countries where these companies are headquartered). Sub-Saharan African companies other than NOCs have been net buyers in their home countries since 2014. They have acquired around $21 billion more in assets from foreign companies than they sold, a difference of around 895 percent. Latin American companies other than NOCs have also been net buyers in their home countries, acquiring around $11 billion more in assets from foreign companies than they sold, a difference of around 277 percent.

Globally, asset transfer trends show a growing role for NOCs. Since 2014, there has been a transfer of around $24 billion in assets from non-NOCs to NOCs, with the value of NOC acquisitions 10 percent larger than the value of NOC sales. Throughout the period, sub-Saharan African NOCs have been net buyers in their home countries, acquiring $3 billion more assets than they sold, a difference of around 167 percent. By contrast, Latin American NOCs have been net sellers in their home countries with the notable exception of Colombia.

The changing face of petroleum companies brings opportunities but also environmental, social and governance (ESG) challenges for producer countries. Publicly listed companies typically have greater and more transparent financial resources than private companies. With a movement of assets to private companies, there is greater need for host governments to ensure buyers have sufficient financial and technical ability to carry out operations in keeping with best industry standards, and to pay for decommissioning at the end of the life of an asset.

Unlike private companies, publicly listed companies must typically disclose a range of information that may help governments and the public understand their ESG commitments or obligations, as well as their capacity to fulfill and their compliance with those commitments or obligations. These may include disclosures on the company's financial condition, pending litigation and, increasingly, emissions management.

Publicly listed companies are also more susceptible to shareholder activism and pressure from lenders or investors to set or strengthen emissions reduction and other climate targets. While local companies (both NOCs and private) may be more committed to local development and strong stakeholder relations in their home countries, their ESG performance may not be an improvement on that of publicly listed IOCs, and may present the same potential drawbacks as (other) private companies—fewer financial resources, weaker commitments to environmental standards and less transparency.

An increasing role for a country's NOCs in its sector may give governments greater control over the development of their resources to deliver revenues or serve domestic energy needs, even if IOCs leave. However, NOCs require adequate public oversight to ensure they do not expose the public purse to unmanageable risk by acquiring projects with high emissions intensities and/or break-even prices that will not be profitable if the world meets its decarbonization commitments.

Like private companies, NOCs often operate less transparently than publicly listed IOCs and/or in a less environmentally responsible manner if they are free from the kinds of disclosure requirements and accountability to shareholders that publicly listed companies have.[6]

6 For example, 62 percent of the 52 NOCs surveyed for the 2017 Resource Governance Index demonstrated "weak," "poor" or "failing" public transparency. See www.resourcegovernance.org/publications/2017-resource-governance-index. See also Patrick R.P. Heller and David Mihalyi, *Massive and Misunderstood: Data-Driven Insights into National Oil Companies* (NRGI, 2019), 54-60, www.nationaloilcompanydata.org/publications.

Governments have a critical role in regulating asset transfers to address these challenges. Governments should:

1. Exercise approval rights to block transfers to unsuitable companies.

Where governments have reserved a legal right to approve assignments of interest in upstream petroleum projects, they should use those rights to vet the quality of potential buyers. Governments should take the broadest interpretation possible of technical competence and "best industry practice" to require that buyers have the competence to maintain or exceed the operating standards of the seller. Assessment of financial competence should include ability to remedy environmental damage that occurred before the transfer, decommission at the closing of the project and/or carry out any community development or corporate social responsibility (CSR) projects, and buyer responsibility for contingent liability under pending litigation. Governments should also review beneficial ownership details of buyers to scrutinize transactions that pose corruption risks and screen out applicants that are ineligible to receive licenses under the law.

2. Publicly disclose relevant information about transfers.

Government should publish information about the process for transferring licenses, including the technical and financial criteria used and any material deviations from such criteria, and information about transferees, including their ultimate beneficial owners. Governments should also disclose the status of decommissioning funding, environmental cleanup liabilities, pending litigation against sellers, and impacts on sellers' community development or CSR projects after the transfer.

3. Strengthen the laws and regulations on asset transfers, emissions management and decommissioning funding.

- Establish approval rights over transfers where they do not exist, with technical and financial competence as conditions for approval and strengthened definitions of "best industry practice" to explicitly include ESG standards.
- Establish or upgrade emissions management and reporting requirements, in keeping with the latest technology and standards, including emissions reporting at the project level where feasible, as project-level data are most useful for host communities and the public.
- Consider strategies to ensure adequate financial resources for decommissioning, including requirements to set up decommissioning funds, requiring sellers to transfer full costs of decommissioning to the decommissioning fund before transferring late-life assets, joint and several liability for decommissioning not only for current operators of the project or asset but all previous owners, and super-priority for decommissioning liabilities over other liabilities in bankruptcy proceedings.

4. Ensure public scrutiny of NOC acquisitions to hold NOCs accountable for managing energy transition risks.

This includes requiring NOCs to publicly disclose investment plans with criteria for acquisitions, details regarding planned acquisitions including the value of the asset and valuation method used to determine the value, the source(s) of financing, the projected capital expenditures required for the asset after acquisition and the NOC's decommissioning liabilities.

Introduction

The need to decarbonize is becoming ever more pressing, but as the world journeys towards a future beyond oil and gas, oil and gas assets will continue to change hands with different kinds of companies filling the gap left behind by others.

There is growing concern that, as publicly listed international oil companies (IOCs) face pressure to reduce emissions, they are selling upstream petroleum assets, in part, to shift emissions off their books and ostensibly achieve their decarbonization goals.[7] Prior research has shown that, on balance, assets are going from publicly listed to private companies and from companies with higher environmental commitments to those with weaker ones.[8] The result, according to some evidence, is that these sales do not simply transfer emissions to new parties but may increase them, as buyers operate these assets with lower environmental standards and/or seek to maximize production from marginal assets.[9,10]

At the same time, some national oil companies (NOCs) are seeking to acquire assets left behind by IOCs to avoid production decline and ensure domestic energy supply.[11]

Recent guidance has focused on oil and gas companies' responsibility to reduce the risk of increased emissions and lower environmental standards when they transfer assets.[12]

Companies should not merely pass on assets without ensuring buyers have the requisite technical and financial capacity to maintain or exceed the seller's operating standards and will face growing reputational risks for using irresponsible exits as part of their net-zero strategies.[13]

However, governments also have a critical role to play in managing the changing face of petroleum investment in their countries to ensure these transfers do not have an overall negative impact in the country.

This briefing identifies broader trends and challenges associated with asset transfers and the changing face of petroleum operators in producer countries, with a focus on the Global South regions and countries where the Natural Resource Governance Institute (NRGI) works.

It then focuses on how governments can exercise their existing rights under law and contract and strengthen their legal frameworks to address the challenges posed by asset transfer trends.

Part I provides a picture of asset transfers trends at global, regional and country levels, and describes risks accompanying these trends, including a growing role for private and local companies, and NOCs in producer countries.

7 See, e.g., U.S. Committee on Oversight and Reform, *Memorandum Re: Investigation of Fossil Fuel Industry Disinformation*.
8 Malek et al., *Transferred Emissions*.
9 See Arnold et al., *Transferred Emissions Are Still Emissions*, 42-50.
10 Rick Steiner, *Just Transition: Reforming Oil Industry Divestment, Decommissioning & Abandonment in the Niger Delta, Nigeria* (Centre for Research on Multinational Corporations, 2023), www.oasis-earth.com/_files/ugd/92a90d_25043ffd87f7434f9b6b58f0c17baf96.pdf.
11 See Furnaro and Manley, *Facing the Future*, 20-21.
12 Measures include pre-deal due diligence on potential buyers' climate standards and capacity, disclosures around asset transfers and their role in emissions reduction strategies to avoid misleading figures that reflect the company's transferred rather than eliminated emissions, adequate provision for decommissioning, support to buyers in maintaining or exceeding the seller's emissions reduction targets, company engagement with host communities and support to host countries' energy transition plans. See Environmental Defense Fund (EDF) Business and Ceres, *Tackling Transferred Emissions: Climate Principles for Oil and Gas Mergers and Acquisitions* (2022), www.business.edf.org/insights/transferred-emissions-climate-principles; Arnold et al., *Transferred Emissions Are Still Emissions*; Nicola Woodroffe and Erica Westenberg, "Governments and companies must address climate and governance risks when petroleum assets change hands," *Columbia FDI Perspectives*, no. 352 (6 March 2023), www.resourcegovernance.org/articles/governments-and-companies-must-address-climate-and-governance-risks-when-petroleum-0.
13 See, e.g., Hiroko Tabuchi, "Oil Giants Sell Dirty Wells to Buyers With Looser Climate Goals, Study Finds," *New York Times*, 10 May 2022, www.nytimes.com/2022/05/10/climate/oilfield-sales-pollution.html.

Part II focuses on how governments can manage asset transfers, first by exercising their existing contractual rights to ensure buyers have the capacity to maintain or exceed sellers' operating practices. It then presents considerations for strengthening the legal framework to address risks that arise from asset transfer trends. Finally, it offers recommendations for ensuring NOC acquisitions are a responsible use of public money and take into consideration energy transition risks, including by increasing public scrutiny of NOC acquisitions.

This briefing can help inform governments' decisions on how to manage divestments from and acquisition in their petroleum sectors to ensure these transfers do not have overall negative impacts on the country. It can also help civil society organizations (CSOs) and the public understand the key issues arising from asset transfer trends globally and in their regions or countries, so they can hold governments and companies accountable for addressing these challenges.

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I. Asset transfer trends and challenges

Prior research on asset transfer trends, focused on transactions between 2017 and 2021, has demonstrated that, on balance and globally, assets are moving from publicly listed to private companies and from companies with higher environmental commitments to those with weaker commitments.[14] Using a different data source, NRGI expanded the period of analysis and focused not only on the global level but on how asset transfer trends may differ by region and country, and therefore present different risks and raise different policy considerations for governments.

Methodology

We analyzed upstream petroleum asset transfers from 2014 to the first half of 2023 (H1 2023), using Rystad data to identify global-, regional- and country-level trends for NRGI's regions and countries of focus.[15,16] The dataset covered 5,200 completed transactions, worth around USD 1.6 trillion, during the time period.[17] Although the results we present are based on closed transactions, we also analyzed transactions that have been announced but have not yet officially closed.

Type of assets

The transactions covered the following types of assets:[18]

- **Field:** an area in which a discovery has been made
- **License:** an area in which there is yet to be a discovery
- **Company:** includes all of a company's assets; company sales values include the values of the fields and licenses transferred in the transaction[19]

Type of companies

We analyzed transactions between the following types of companies:

- **National oil company (NOC) vs non-NOC.** This classifies all companies as either NOC or non-NOC, based on Rystad's classification (with some manual adjustments). Rystad defines a company as an NOC if a state owns at least 50 percent of its shares.[20]
- **Publicly listed company vs private company.** This classifies all companies as either publicly listed or private (including NOCs), based on Rystad's classification (with some manual adjustments). Rystad defines a company as publicly listed if any of its shares are listed on a stock exchange. NOCs are also categorized as publicly listed if any of their shares are publicly listed.[21]

14 Malek et al., *Transferred Emissions*.

15 NRGI's countries of focus for the oil and gas industry are Ghana, Nigeria, Senegal and Uganda in sub-Saharan Africa and Colombia, Mexico and Peru in Latin America. Our regional analysis covers sub-Saharan Africa as a whole and Latin America and the Caribbean as a whole.

16 General data are from Rystad Energy's Exploration & Production Mergers & Acquisitions database and asset economics data from Rystad's UCube (www.rystadenergy.com/).

17 Data on transactions in H1 2023 did not appear to be comprehensive at the time of analysis, however.

18 This briefing also refers to "projects," which the Extractive Industries Transparency Initiative defines as meaning "operational activities governed by a single contract, license, lease, concession or similar legal agreement" or "multiple such agreements" that are "substantially interconnected." See EITI Standard (2023), Requirement 4.7, www.eiti.org/eiti-requirements.

19 When a company has assets in multiple countries, Rystad allocates the value of the transaction between countries based on the net present value of the assets involved.

20 NOC acquisitions in their home countries can either entail a NOC purchasing an asset or the NOC taking over an asset that has been relinquished by another company(ies).

21 A notable complication with this analysis is that a joint venture (JV) between publicly listed companies is classed as a private company if the JV itself is not publicly listed. While this is the correct classification, a JV of this nature might operate more like a publicly listed company, considering its owners.

- **Local company (other than NOC) vs foreign company.** This classifies all non-NOCs with a headquarters in the country of focus as a local company, to analyze the flows between local and foreign companies.
- **Local NOC vs all other companies.** This classifies all NOCs with a headquarters in the country of focus as a local NOC, to analyze the flows between local NOCs and all other companies.

Valuation

Rystad applies a valuation to an asset transfer in one of two ways. Rystad uses the amount of money that actually changed hands when this is reported. When this amount is not reported, Rystad bases its valuation on its own modeling of the net present value of the asset from the time of transfer onwards.[22,23]

Break-even price and emissions intensity

We also sought to determine whether, on balance, companies from our regions and countries of focus take on assets with break-even prices and/or higher emissions intensities that in future could become unprofitable under different energy transition and carbon pricing scenarios, thereby exposing themselves to greater financial risk.[24] For the largest transactions that involve companies from our focus regions and countries, we therefore assessed the break-even price and emissions intensity of these assets (when that data was available).

Break-even price

The break-even price is the long-term price at which a project needs to sell its production to be profitable. Rystad's break-even price, reported in USD per barrel of oil equivalent (boe), assumes a nominal discount rate of 10 percent.[25] The scenarios we used to assess potential future profitability on the basis of forecast break-even price involve NRGI estimates that are based on the International Energy Agency (IEA)'s demand projections and Rystad's supply projections. The IEA's Announced Pledges Scenario (APS) assumes that all aspirational targets announced by governments are met on time and in full, including their long-term net-zero and energy access goals. The IEA's Net Zero Emissions (NZE) scenario assumes the world achieves net zero CO2 emissions by 2050.

For each of the IEA scenarios, we estimated oil prices over the period 2024 to 2050. To do this, we extrapolated levels of demand over time using the current demand for oil and the IEA's estimates for 2030 and 2050 in its two scenarios. We then took oil industry cost curves from Rystad across this period and estimated the price in each year by finding the break-even price of the marginal project in each cost curve equal to our extrapolated demand. The result is an average price in 2024–2050 of $43 a barrel in the APS and $17 in the NZE scenario.[26]

22 This value is based on the oil price in Rystad's base case scenario. Cash flows are discounted at a nominal rate of 10 percent.
23 This approach means, for example, that NOC acquisitions which result from relinquishment with no money changing hands still have a value applied to them.
24 When reporting averages for a given region or country, we have weighted them using the value of the transactions (so the break-even price and emissions intensity have a larger impact on the average for a larger transaction than a smaller transaction).
25 The break-even price should broadly reflect what the parties to the transaction faced at the time of the transaction. The break-even price we have used depends on whether the asset has already reached final investment decision (FID). If it is yet to reach FID, an estimated break-even price at the point of FID is used. If it has already reached FID, the break-even price from the current year onwards is used. Many transactions involve more than one asset. In this case, an average break-even price is calculated, weighted by the volume of remaining production. This break-even price is then compared to the average price over the period in which the project is producing in the two global price scenarios.
26 Further explanation of the methodology is provided in David Manley, Andrea Furnaro and Patrick R.P. Heller, *Riskier Bets, Smaller Pockets: How National Oil Companies Are Spending Public Money Amid the Energy Transition* (NRGI, 2023), www.resourcegovernance.org/publications/riskier-bets-smaller-pockets-national-oil-companies-public-money-energy-transition. However, the price projections reported in the *Riskier Bets* report are slightly different because of the different period of analysis.

Emissions intensity

Emissions intensity is reported as kilograms of CO2 per boe. We compared the emissions intensity of the assets involved in a transaction to the average emissions intensity of all transacted assets since the start of 2014 for which Rystad provides data. This approach has significant limitations, however. First, without data on the emissions intensity of assets that have not been part of a transaction during this period, it is unclear whether this average is a reasonable indicator of the average intensity of all assets (e.g., transactions could be more likely to involve dirtier assets, or vice versa). Second, even the data for assets that have been part of a transaction are not comprehensive, and therefore it is unclear whether this average is a reasonable indication of the average intensity of all transacted assets.

We think it important to include consideration of emissions intensity in risk assessment for petroleum asset acquisitions, and have therefore included this approach as illustrative. However, more work is needed to improve accuracy and better understand whether and the extent to which emissions intensity plays a role in which assets get transferred and to which kinds of companies.

Other limitations

Our analysis has several other limitations, including incorrectly marked or missing company type and headquarters information in Rystad's database, or the possibility of missing or inaccurate transaction details in the database. Rystad collects data on mergers and acquisitions from company and media reporting and from discussions with industry actors. We spot-checked the information on the largest transactions for NRGI countries for obvious errors based on readily available public information. However, more detailed cross-checking against alternative sources would be necessary to improve accuracy.

Trends and challenges

The kind of companies acquiring assets on balance has different policy implications for governments. For example, a net transfer of assets to a producer country's NOC suggests an increasing role for the state, with both the benefits and risks this implies, while an increasing role for private versus publicly listed companies has implications for the public availability of information on the sector.

Going behind closed doors: flows from publicly listed to private companies

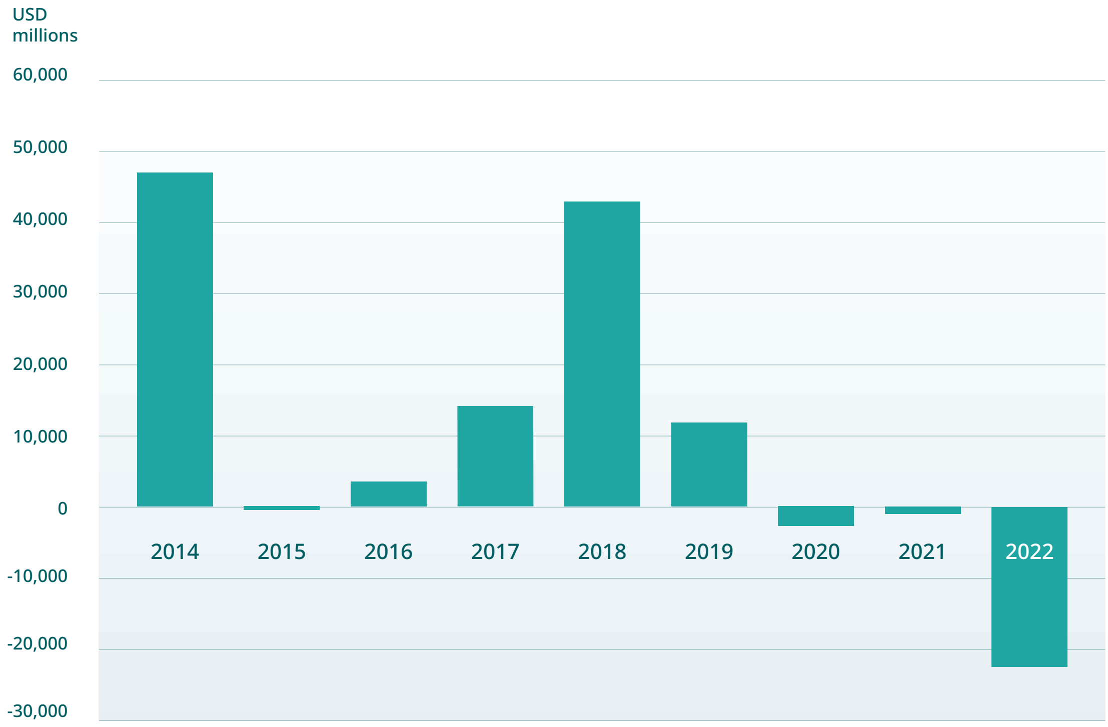
Prior research has indicated that, on balance, petroleum assets tend to move from publicly listed to private companies, potentially drawing the petroleum sector into an even murkier world where companies' practices (or malpractices) are hidden from public view.[27]

Our analysis also shows that, globally, assets are moving from publicly listed to private companies during the period studied. Since the start of 2014, around $88 billion in assets have moved from publicly listed to private companies.[28] Although this trend has reversed since 2020, with assets moving from private to publicly listed companies, announced transactions would continue the trend of transfers from public to private hands.

27 See Malek et al., *Transferred Emissions*. This research analyzed upstream mergers and acquisitions from 2017 through 2021 using data from Refinitiv (now renamed LSEG: www.lseg.com/en).

28 In the context of all the transactions that private companies concluded during this period, this translated to the value of private company acquisitions being 18 percent larger than the value of private company sales. For publicly listed companies, this translated to the value of their acquisitions being 8 percent smaller than the value of their sales.

Figure 1. Net transfer from publicly listed to private companies across the world (closed transactions)



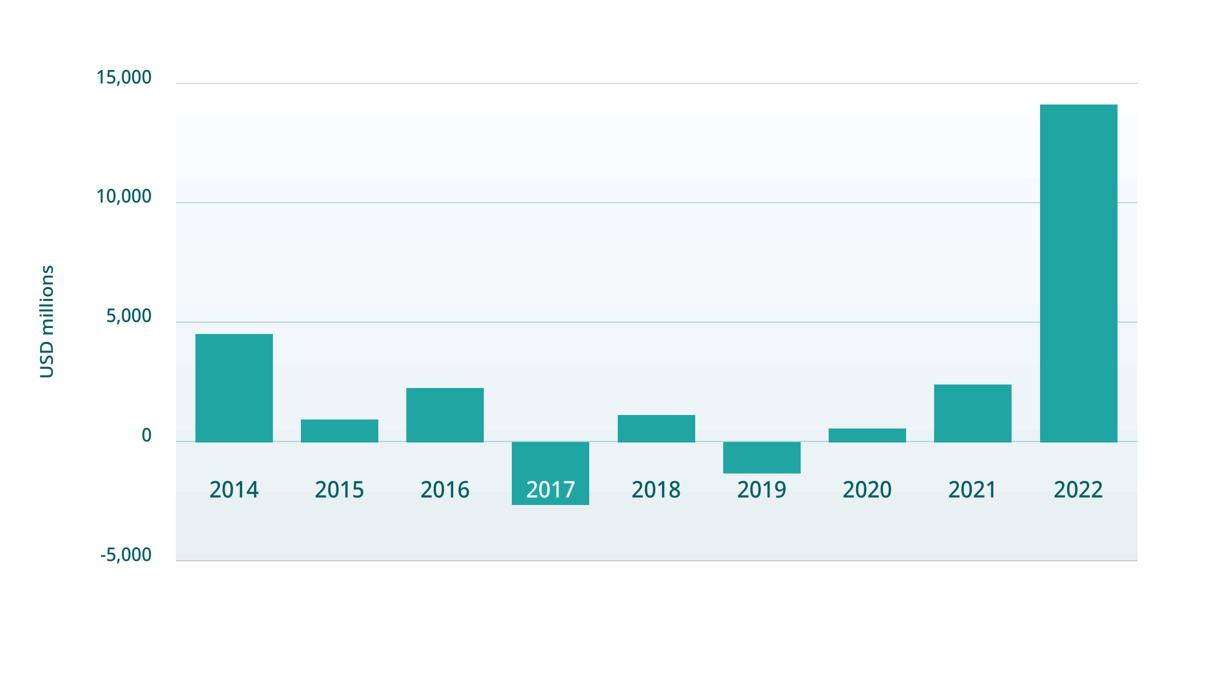
Both sub-Saharan Africa and Latin America have seen a net transfer of assets by publicly listed companies to private companies during the period. In sub-Saharan Africa, there has been a transfer of around $23 billion in assets from publicly listed to private companies since the start of 2014.

Publicly listed company acquisitions have been around 37 percent smaller than publicly listed company sales.[29] Private company acquisitions have been around 149 percent larger than private company sales.[30] Announced transactions would continue the trend of transfers from publicly listed to private companies.

29 They acquired assets worth $38.1 billion and sold assets worth $60.7 billion.

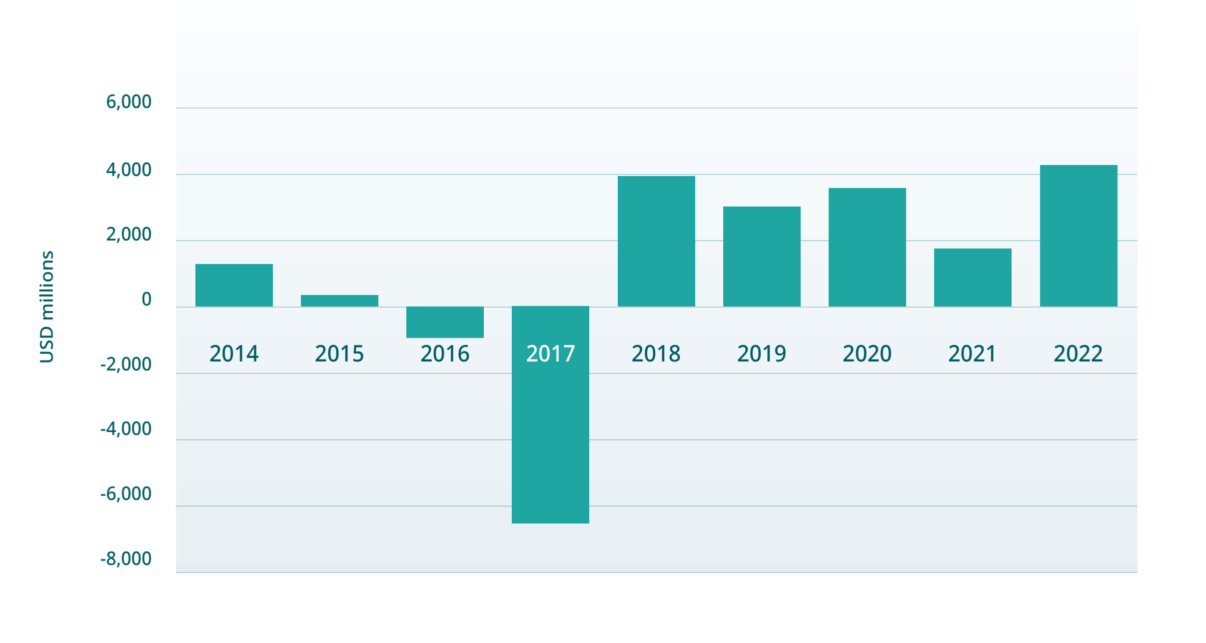
30 They acquired assets worth $37.8 billion and sold assets worth $15.2 billion. A large proportion of this asset transfer is accounted for by Eni and BP merging their Angolan operations to form a new independent joint venture in 2022. Even without this transaction, however, the value of publicly listed company sales would be 18 percent higher than the value of their acquisitions, and the value of private company acquisitions would be 53 percent higher than the value of their sales, both of which are higher than the global average.

Figure 2. Net transfer from publicly listed to private companies in sub-Saharan Africa (closed transactions)



In Latin America, around $11 billion in assets moved from publicly listed to private companies during the period. Publicly listed company acquisitions were around 8 percent smaller than publicly listed company sales.[31] Private company acquisitions were around 39 percent larger than private company sales.[32] Announced transactions would continue this trend.

Figure 3. Net transfer from publicly listed to private companies in Latin America (closed transactions)



31 They acquired assets worth $113.4 billion and sold assets worth $123.9 billion.
32 They acquired assets worth $38.7 billion and sold assets worth $27.9 billion.

Unlike private companies, publicly listed companies must typically disclose a range of information that may help governments and the public understand their ESG commitments or obligations, as well as their capacity to fulfill and their compliance with those commitments or obligations. These may include disclosures on the company's financial condition, pending litigation and, increasingly, emissions management.[33]

For example, the European Union's Corporate Sustainability Reporting Directive requires EU publicly listed companies (and also large private EU companies and non-EU entities with significant activities in the EU) to make material environmental, social and human rights, and governance disclosures. Environmental disclosures include information on a company's efforts to limit global warming to 1.5°C and disclosures on their Scope 1, 2 and 3 emissions, as well as disclosures on the company's impacts on water and marine resources, biodiversity and ecosystems, and disclosures on the circular economy. Social impact disclosures include information on the company's own workforce, workers in their value chain, and the company's impacts on affected communities and consumers, while governance includes disclosures on anti-corruption and anti-bribery practices.[34,35]

The United Kingdom also requires publicly listed U.K. companies and many large companies to report their emissions and make disclosures on their identification, assessment and management of climate-related risks and opportunities, in line with the recommendations of the Task Force on Climate- Related Financial Disclosures.[36]

Rules proposed by the United States Securities and Exchange Commission would also require publicly listed companies to disclose climate-related risk, governance and risk management processes for those risks, and the company's emissions, while the U.S. state of California has already passed its own climate disclosure law.[37]

Publicly listed companies are also more susceptible to shareholder activism and pressure from lenders or investors to set or strengthen emissions reduction and other climate targets.[38]

Nevertheless, it is not a given that private companies will perform worse than publicly listed companies on their ESG management.[39] Nor is it a given that publicly listed international companies will implement the highest operating standards without clear regulation requiring them to do so. For example, a U.S. congressional committee investigation showed that IOCs' internal operational decisions do not always match their public rhetoric.

33 For example, U.S. securities regulation requires companies to disclose any material pending legal proceedings. See U.S. Securities and Exchange Commission, Regulation S-K, Item 103, 17 CFR § 229.103, www.sec.gov/files/rules/final/2020/33-10825.pdf.

34 Impacts on affected communities include impacts on Indigenous peoples' rights, on civil rights, and on social and economic rights (such as the right to water as part of the right to an adequate standard of living).

35 See EU, *Annex to the Commission Delegated Regulation (EU) … / … supplementing Directive 2013/34/EU of the European Parliament and of the Council as regards sustainability reporting standards* (2023), www.eur-lex.europa.eu/legal-content/EN/TXT/?uri=pi_com%3AC%282023%295303. See also Cooley, "EU Adopts Long-Awaited Mandatory ESG Reporting Standards," 11 August 2023, www.cooley.com/news/insight/2023/2023-08-11-eu-adopts-long-awaited-mandatory-esg-reporting-standards, for a helpful summary of the rules. See also generally Arnold et al., *Transferred Emissions Are Still Emissions*, 11-25, for an overview of various disclosure requirements.

36 See U.K. Department for Business, Energy & Industrial Strategy, *Mandatory climate-related financial disclosures by publicly quoted companies, large private companies and LLPs: Non-binding guidance* (February 2022), www.assets.publishing.service.gov.uk/media/62138625d3bf7f4f05879a21/mandatory-climate-related-financial-disclosures-publicly-quoted-private-cos-llps.pdf, and U.K. (HM Government), *Environmental Reporting Guidelines: Including streamlined energy and carbon reporting guidance* (March 2019), www.assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/850130/Env-reporting-guidance_inc_SECR_31March.pdf.

37 See U.S. Securities and Exchange Commission, *Fact Sheet: Enhancement and Standardization of Climate-Related Disclosures*, www.sec.gov/files/33-11042-fact-sheet.pdf. See also Henry Engler, "Companies need to integrate climate reporting across functions to comply with California's new law," *Thomson Reuters*, 20 October 2023, www.thomsonreuters.com/en-us/posts/esg/california-climate-reporting-law/.

38 See Alex Blackburne, "Activist investors turning up heat on oil majors in proxy voting season," *S&P Global Market Intelligence*, 25 April 2022, www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/activist-investors-turning-up-heat-on-oil-majors-in-proxy-voting-season-69438831. However, the impact of this activism seems to be waning as energy security concerns loom large in the wake of Russia's invasion of Ukraine. See Sabrina Valle, "Exxon, Chevron shareholders soundly reject climate-related petitions," *Reuters*, 31 May 2023, www.reuters.com/sustainability/exxon-shareholders-reject-climate-proposals-activist-annual-meeting-2023-05-31/. See also investor initiatives pushing companies to take action on climate change such as Climate Action 100+, www.climateaction100.org/.

39 As noted, some laws on emissions disclosure earlier referenced also include large private companies, but obligations for private companies may differ from those for publicly listed companies, while small private companies are not covered. For example, under the U.K.'s "streamlined energy and carbon reporting guidance," publicly listed companies should report emissions for which they are responsible, including their global energy consumption as used to calculate those emissions, whereas large private companies are generally required to report U.K. energy use and the associated emissions from that energy use. See U.K. (HM Government), *Environmental Reporting Guidelines*, ch. 2, sections 6, 7. The U.S. Securities and Exchange Commission rules would apply to publicly listed companies.

The committee provided an example of an email exchange among senior employees of an IOC in which a decision was made not to use a project design that would reduce emissions. One executive justified the decision stating that the company had "no obligation to minimize GHG emissions" and should only "'minimize [GHG emissions] where it makes commercial sense,' is required by code, or fits into a regional strategy."[40]

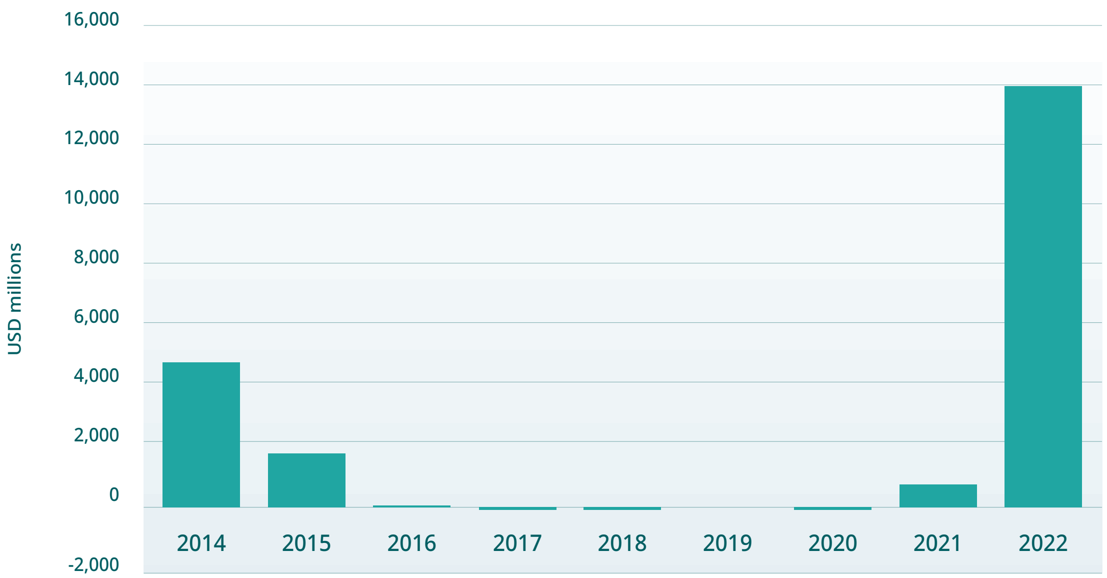
Petroleum producing and exporting countries that want to remain competitive will face increasing pressure to minimize emissions from petroleum operations, as investors, customers and importing countries prioritize low-emission fossil fuels.[41] It is therefore in their interest to ensure a consistent standard of behavior across different types of companies by strengthening the regulatory framework to enshrine in law emissions and other ESG management and reporting practices.

Localization: flows from foreign to local companies

Sub-Saharan African and Latin American companies have been playing an increasing role in their home countries (the countries where these companies are headquartered). Sub-Saharan African companies other than NOCs have been net buyers in their home countries since the start of 2014.

They have acquired around $21 billion more in assets than they have sold to foreign companies, a difference of around 895 percent.[42] Although $14 billion of this investment is accounted for by Eni and BP merging their Angolan operations to form a new independent joint venture in 2022, most of the remaining amount is acquisitions by Nigerian companies. Nigeria has seen a trend of IOCs exiting onshore assets (Table 1) and shifting their focus to offshore projects.[43]

Figure 4. Net transfer from foreign companies to sub-Saharan African companies other than NOCs in their home countries (closed transactions)



40 U.S. Committee on Oversight and Reform, *Memorandum Re: Investigation of Fossil Fuel Industry Disinformation*, 21. The emails among BP employees concerned whether to invest in methods for curbing emissions from the company's Angelin gas project off the coast of Trinidad and Tobago.

41 See generally William Davis and Amir Shafaie, *Extracting Emissions: Why Resource-Rich Countries Should Cut Emissions from Extractive Operations* (NRGI, 30 November 2023), www.resourcegovernance.org/publications/extracting-emissions-why-resource-rich-countries-should-cut-emissions-extractive. For example, a new EU regulation will require oil, gas and coal companies to measure, monitor, report and verify their methane emissions and require exporters to the EU to apply the same obligations to their oil, gas and coal producers. See European Commission, "Commission welcomes deal on first-ever EU law to curb methane emissions in the EU and globally," 15 November 2023, www.ec.europa.eu/commission/presscorner/detail/en/IP_23_5776.

42 They acquired assets worth $23.4 billion and sold assets worth $2.4 billion.

43 See Stakeholder Democracy Network (SDN), *Divesting from the Delta: Implications for the Niger Delta as international oil companies exit onshore production* (October 2021), www.stakeholderdemocracy.org/report-divestment/.

Table 1. Nigeria's top 10 closed transactions

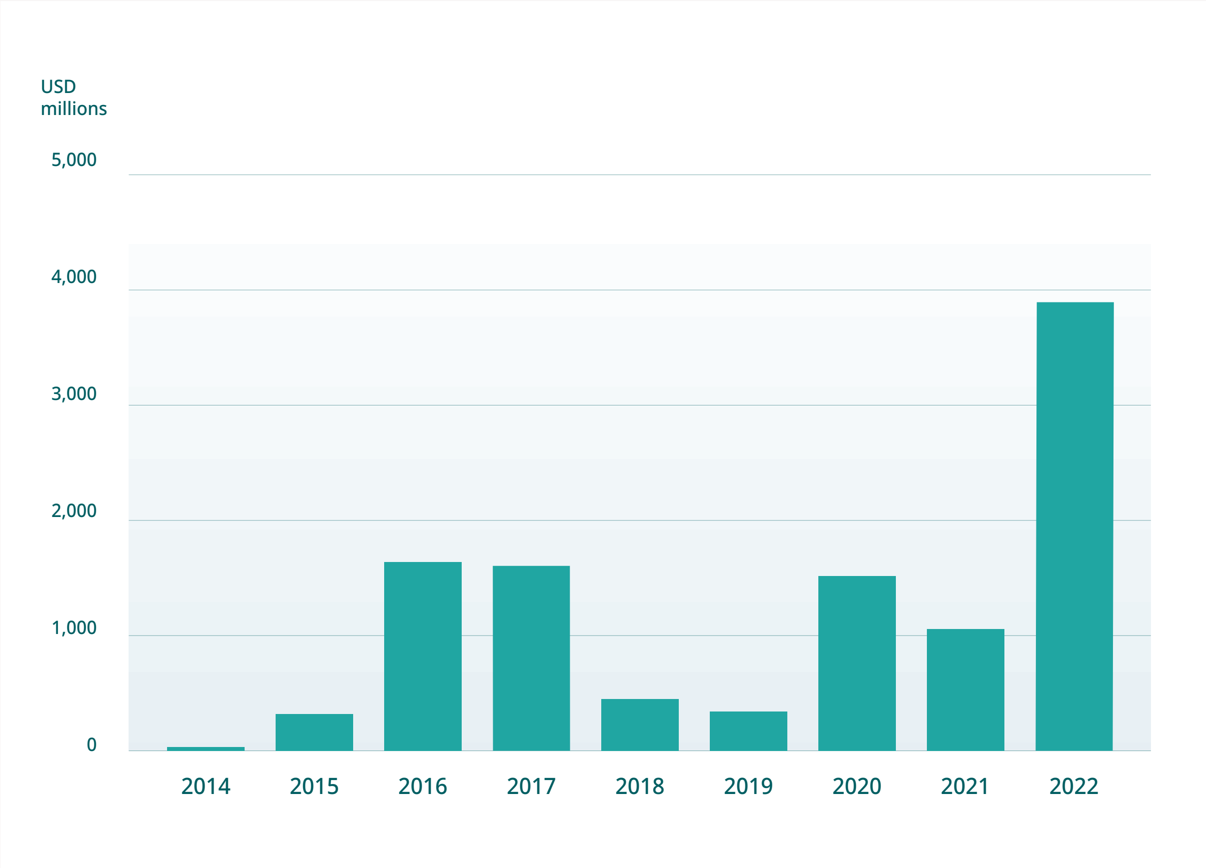
Year	Seller	Buyer	Type	Value ($ million)
2014	Shell (Netherlands), TotalEnergies (France)	Aiteo Eastern E&P Company Limited (Nigeria)	Field acquisition	2,369
2014	Eni (Italy), TotalEnergies (France), Shell (Netherlands)	Newcross Exploration and Production Limited (Nigeria)	Field acquisition	1,800
2018	Petrobras (Brazil)	Africa Oil Corp (Canada)	Field acquisition	1,407
2021	Shell (Netherlands)	TNOG (Nigeria)	Field acquisition	533
2015	BG (U.K.)	Shell (Netherlands)	Company acquisition	511
2019	Eland Oil & Gas (Nigeria)	Seplat Energy (Nigeria)	Company acquisition	484
2015	Shell (Netherlands)	Sahara Energy Field Limited (Nigeria)	Field acquisition	442
2022	Sinopec Group (parent) (China)	NNPC (Nigeria)	Field acquisition	394
2017	Seven Energy Nigeria (Nigeria)	Savannah Energy (U.K.)	Field acquisition	280
2014	Eni (Italy)	Tempo Energy Resources (Nigeria)	Field acquisition	270

Latin American companies other than NOCs have also been net buyers in their home countries since the start of 2014. They acquired around $11 billion more in assets than they sold to foreign companies, a difference of around 277 percent.[44] Argentinian and Brazilian companies accounted for nearly $9 billion of this investment. Colombian, Mexican and Trinidadian companies accounted for most of the rest.

Governments' local content policies have long aimed to increase local participation in and benefits from the oil and gas sector.[45] An increasing role for local companies in their home countries aligns with many countries' local content policy objectives.

Local companies may in theory be more committed to local development and strong stakeholder relations. However, governments should be aware that local companies' ESG performance may not be an improvement on that of IOCs. Local private companies, in particular, present the same potential drawbacks as private companies more generally—weaker commitments to environmental standards and less transparency.[46] Some also lack the financial and technical capacity to operate assets safely and in an environmentally responsible manner.[47] A strong regulatory framework can help ensure local companies operate with best industry standards.

Figure 5. Net transfer from foreign companies to Latin American companies other than NOCs in their home countries (closed transactions)



44 They acquired assets worth $14.7 billion and sold assets worth $3.9 billion.

45 See generally Silvana Tordo, Michael Warner, Osmel E. Manzano and Yahya Anouti, *Local Content Policies in the Oil and Gas Sector* (World Bank, 2013), www.documents1.worldbank.org/curated/en/549241468326687019/pdf/Local-content-in-the-oil-and-gas-sector.pdf.

46 See Malek et al., *Transferred Emissions*, 27-29, providing examples of higher flaring and a slower plugging rate of inactive wells in assets that were sold by public to local private companies in Texas, U.S., and the Niger Delta, Nigeria.

47 See Steiner, *Just Transition*.

As IOCs pull out of the Niger Delta, Nigerian companies step in

The Niger Delta in Nigeria has long been fraught with tensions between IOCs and communities. Oil operations since the late 1950s characterized by oil spills and oil well fires have left a legacy of environmental devastation. Communities have paid the price. Pollution has despoiled their groundwater, fishing grounds and agricultural land, and destroyed their livelihoods.[48] Years of conflict, sabotage and theft have ensued. With lawsuits against IOCs pending and slow, and inadequate cleanup, IOCs have been pulling out of the Niger Delta over the last decade, leaving unresolved issues behind.[49]

Some communities say local companies are no improvement on IOCs and may be even worse.[50] Residents, local officials and environmental groups report that local companies have failed to respond quickly to oil spills and have dramatically increased the practice of flaring natural gas, resulting in higher greenhouse gas emissions and intensified local pollution.[51] Local companies have not always fulfilled their CSR promises.[52] At the same time, information about such companies' operations is harder to come by as they are less transparent and less accountable to investors."[53]

While some Nigerian researchers have welcomed greater local participation in the sector and the potential for local companies to build more equitable relationships with host communities, they have raised concerns about local companies' financial and technical capacity. According to Nigeria's Stakeholder Democracy Network (SDN), local Nigerian companies spill 35 percent more oil relative to their production than do IOCs and flare more than 10 times more gas per barrel of oil produced.[54] SDN has highlighted that communities have been able to sue IOCs abroad for the actions of their local subsidiaries but will have more difficulty holding local companies to account via the domestic court system.

48 See, e.g., United Nations Environment Programme, *Environmental Assessment of Ogoniland* (2011), www.unep.org/resources/assessment/environmental-assessment-ogoniland-site-factsheets-executive-summary-and-full#:~:text=This%20major%20independent%20scientific%20assessment,The%20assessment%20has%20been%20unprecedented.

49 See Ekpali Saint, "Niger Delta decries slow cleanups, decades after oil spills," *Al Jazeera*, 20 December 2022, www.aljazeera.com/features/2022/12/20/un-recommended-cleanup-of-delta-pollution-lags; Amnesty International, "Nigeria: Shell must clean up devastating oil spills in the Niger Delta," 2 February 2023, www.amnesty.org/en/latest/news/2023/02/nigeria-shell-oil-spill-trial/; Macdonald Dzirutwe, "Nigeria needs $12 billion to clean up Bayelsa oil spills-report," *Reuters*, 16 May 2023, www.reuters.com/business/environment/nigeria-needs-12-billion-clean-up-bayelsa-oil-spills-report-2023-05-16/; Audrey Gaughran, Nabie Nubari Francis and Emeka Duruigbo, *Selling out the Niger Delta* (SOMO, 2024), www.somo.nl/selling-out-the-niger-delta/#.

50 Steiner, *Just Transition*, 14.

51 Rachel Chason, "Big Oil is selling off its polluting assets—with unintended consequences," *Washington Post*, 27 March 2023, www.washingtonpost.com/world/2023/03/27/shell-nigeria-niger-delta-oil/.

52 See SDN, *Divesting from the Delta*, 16.

53 Chason, "Big Oil is selling off its polluting assets."

54 Ibid. See SDN, *2018 Nigerian oil industry environmental performance index* (2020), www.stakeholderdemocracy.org/wp-content/uploads/2020/03/EPI-Report-01.07.20-DT-DIGITAL.pdf.

As IOCs pull out of the Niger Delta, Nigerian companies step in

Host communities have voiced concern that IOCs are trying to escape liability for historic pollution. Lack of clarity on the extent to which local buyers have assumed liabilities is naturally worrying, considering clean-up could cost billions of dollars.[55]

Most local companies have relied on loans from Nigerian banks to fund their acquisitions, and lending to oil and gas companies represents 30 to 40 percent of Nigerian banks' loan assets.[56] Nigerian companies now hold 45 percent of oil licenses compared to 47 percent held by oil majors and will hold the majority of licenses if ExxonMobil's sale to Nigeria's Seplat Energy is approved.[57] Nigerian banks are therefore highly exposed to the risk of default by local companies and to energy transition risks more broadly. Indeed, several loans from Nigerian banks to finance acquisitions by local companies are reportedly in default.[58]

According to our analysis, the 10 largest acquisitions by local Nigerian companies appear profitable, on average, if APS materializes. However, given that their average break-even price is only $3 per barrel lower than APS prices, and oil and gas projects often suffer from cost overruns compared to initial estimates, profitability is not guaranteed even in this scenario.[59] These projects will not break even if NZE materializes. Their high average emissions intensity relative to other assets transferred during the period studied also makes them risky.

Nigerian CSOs have developed National Principles for Responsible Petroleum Industry Divestment to address the range of issues arising from divestment trends in Nigeria.[60]

55 See SDN, *Divesting from the Delta*, 12, 18; Gaughran, Francis & Duruigbo, *Selling out the Niger Delta*.

56 Matt Smith, "Oil exposure raises questions for West Africa's big banks in the age of coronavirus," *S&P Global Market Intelligence*, 16 July 2020, www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/oil-exposure-raises-questions-for-west-africa-s-big-banks-in-age-of-coronavirus-59406320.

57 Chason, "Big Oil is selling off its polluting assets."

58 Steiner, *Just Transition*, 4.

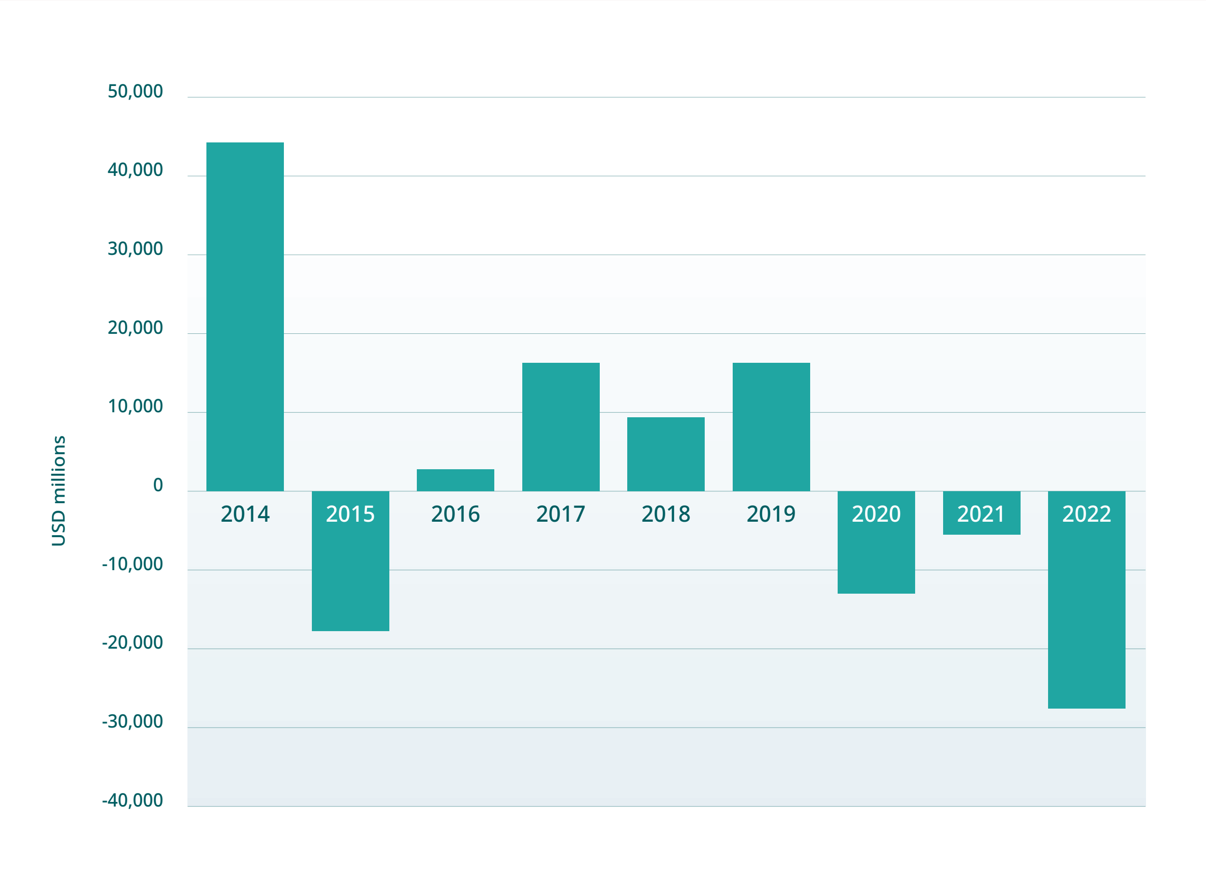
59 EY, *Spotlight on Oil and Gas Megaprojects* (2014), www.yumpu.com/en/document/read/45994813/ey-spotlight-on-oil-and-gas-megaprojects.

60 National Principles for Responsible Petroleum Industry Divestment (2023), www.stakeholderdemocracy.org/wp-content/uploads/2023/12/National-Principles-for-Responsible-Petroleum-Industry-Divestment-B.pdf.

NOCs advance as IOCs retreat: flows from non-NOCs to NOCs

Global asset transfer trends suggest an increasing role for NOCs. Since the start of 2014, there has been a transfer of around $24 billion in assets from non-NOCs to NOCs, with the value of NOC acquisitions 10 percent larger than the value of NOC sales.[61]

Figure 6. Net transfer from non-NOCs to NOCs across the world (closed transactions)



61 They acquired assets worth $269.8 billion and sold assets worth $245.8 billion.

Throughout the period, sub-Saharan African NOCs have been net buyers in their home countries, acquiring over $3 billion more assets than they sold, a difference of around 167 percent.[62] The government/NOC of Chad accounted for the largest proportion of asset purchases (by value) (Table 2).

Table 2. Sub-Saharan African NOCs' top 10 closed acquisitions in their home countries

Year	Asset country	Buyer	Seller	Type	Value ($ million)
2014	Chad	Government of Chad (Chad)	Chevron (U.S.)	Field acquisition	1,300
2020	Congo	SNPC (Congo)	TotalEnergies (France), Eni (Italy), QatarEnergy (Qatar)	Field acquisition	677
2017	Angola	Sonangol (Angola)	Cobalt International Energy (U.S.)	Field acquisition	500
2023	Nigeria	NNPC (Nigeria)	Sinopec (China)	Field acquisition	394
2023	Chad	Government of Chad (Chad)	Petronas (Malaysia)	Field acquisition	371
2021	Ghana	GNPC (Ghana)	Occidental Petroleum (Ghana)	Field acquisition	200
2020	Senegal	Petrosen (Senegal)	Capricorn Energy (U.K.), FAR Limited (Australia), Woodside (Australia)	Field acquisition	195
2018	Angola	Sonangol (Angola)	BP (U.K.)	Field acquisition	179
2017	Senegal	AGC (Senegal)	Forza Petroleum (Canada)	Field acquisition	177
2017	Equatorial Guinea	GEPetrol (Equatorial Guinea)	Noble Energy (United States)	Field acquisition	138

62 They acquired assets worth $5.6 billion and sold assets worth $2 billion.

By contrast, Latin American NOCs have been net divestors in their home countries. The notable exception is Colombia, whose government/NOC acquired $4 billion more Colombian assets than it sold during the period (Table 3).

Table 3. Colombia's top 10 closed transactions

Year	Seller	Buyer	Type	Value ($ million)
2016	Frontera Energy Corporation (Canada)	Ecopetrol (Colombia)	Field acquisition	2,982
2014	Talisman Energy (Canada)	Repsol (Spain)	Company purchase	1,720
2020	Occidental Petroleum (United States)	SierraCol Energy (Colombia)	Field purchase	825
2016	Petrolatina Energy (U.K.)	Gran Tierra Energy (U.S.)	Company acquisition	525
2020	Repsol (Spain)	Ecopetrol (Colombia)	Field acquisition	343
2019	Amerisur (Colombia)	GeoPark (Argentina)	Company acquisition	314
2016	Occidental Petroleum (U.S.)	Ecopetrol (Colombia)	Field acquisition	286
2015	ExxonMobil (U. S.)	Canacol Energy (Brazil)	Field acquisition	249
2014	Verano Energy (Canada)	Parex Resources (Canada)	Company acquisition	181
2015	ExxonMobil (U. S.)	Vetra Energy (Colombia)	Field acquisition	139

Some sub-Saharan African government representatives have expressed concern about the impact the retreat of foreign investors will have on their ability to develop their petroleum resources.[63] An increasing role for a country's NOCs in its sector may give governments greater control over the development of their resources to deliver revenues or serve domestic energy needs, even if IOCs leave. It can also provide governments with more autonomy in determining how and when to wind down their petroleum sectors.

At the same time, journalists and researchers have raised concerns that, like private companies, NOCs may operate less transparently than publicly listed IOCs or in a less environmentally responsible manner without the disclosure requirements and accountability to shareholders that publicly listed companies have.[64] Indeed many NOCs have poor public transparency practices.[65] However, it is not a given that NOCs will operate with lower environmental standards and with greater opacity than IOCs. Non-listed NOCs like ADNOC, Pemex and Qatar Energy have published sustainability reports and used globally recognized ESG reporting frameworks.[66] Further, a strengthened regulatory framework with respect to emissions management and disclosure could address deficits in transparency and environmental management.

However, in addition to operational concerns, a key issue in evaluating NOC acquisitions is whether these are prudent use of public funds. As NRGI has argued elsewhere, many NOCs are likely to make investments in projects that could prove unprofitable as the energy transition advances and reduces demand and prices for fossil fuels. NRGI has found that $425 billion—or a quarter—of planned NOC investment over the next 10 years in development or expansion of oil and gas projects will not be profitable under the APS scenario where governments implement all their climate pledges.[67] Imprudent NOC acquisitions in future will only add to this risk.

Many of the assets that sub-Saharan African and Latin American NOCs have acquired since the start of 2014—through both purchases and taking over of relinquished assets—appear vulnerable to energy transition risks. NOCs in these two regions are taking on some of the riskiest assets as IOCs dispose of them.

The 10 largest sub-Saharan African NOC acquisitions during the period studied only just break even, on average, if APS materializes, while Latin American NOC acquisitions fail to break even. Acquisitions by Colombian, Ghanaian, Nigerian, Senegalese and Ugandan NOCs in particular appear unprofitable if APS materializes (Table 4). Nigeria's acquisitions, such as NNPC's takeover of four licenses from Sinopec-owned Addax in 2023, appear particularly risky. Nigerian NOC acquisitions have an average break-even price that is $21 per barrel above APS prices and significantly higher emissions intensity than average.[68] Mexican NOC acquisitions, by contrast, appear profitable if APS materializes, though not in the NZE scenario.

The risks facing some of these NOCs are also impacted by the profitability of assets they have sold (Table 5). For example, Colombian NOCs have acquired significantly more assets than they have sold, but the assets they have sold have a much higher break-even price (and are therefore riskier) than the assets that they have acquired. By contrast, Ghanaian NOCs have further increased the riskiness of their portfolio by selling assets that have a lower break-even price than their acquired assets.

NOCs from these countries have announced only a few future transactions, although more are on the horizon. For example, Senegal's NOC, Petrosen, is aiming to increase its current 10 percent interest in the Yakaar-Teranga project to 34 percent at the start of the production phase.[69] Clear criteria for acquisitions that incorporate energy transition considerations is critical for ensuring NOCs' acquisitions are within acceptable risk levels for the company and the country.

63 See, e.g., Norvan Reports, "GNPC CEO attributes Aker/AGM acquisition move to 'fear of lack of development of oil blocks' by IOCs," 2021, www.norvanreports.com/gnpc-ceo-attributes-aker-agm-acquisition-move-to-fear-of-lack-of-development-of-oil-blocks-by-iocs/.

64 See, e.g. Rachel Adams-Heard, Laura Hurst and Kevin Crowley, "The Retreat of Exxon and the Oil Majors Won't Stop Fossil Fuel," *Bloomberg*, 9 June 2021, www.bloomberg.com/news/features/2021-06-09/as-exxon-and-shell-retreat-oil-nations-step-up.

65 See footnote 6.

66 See Furnaro and Manley, *Facing the Future*.

67 Manley, Furnaro and Heller, *Riskier Bets, Smaller Pockets*.

68 As previously indicated, the comparison of emissions intensity is against only assets transferred during the period.

69 Aida Diop, Papa Daouda Diene and Amir Shafaie, "Between Delays and BP's Exit, Senegalese Gas Projects Prompt Concern," NRGI, 12 December 2023, www.resourcegovernance.org/articles/between-delays-and-bps-exit-senegalese-gas-projects-prompt-concern.

Table 4. Average weighted break-even prices per barrel (bbl) and emission intensities of assets that are part of the top 10 closed acquisitions by sub-Saharan African and Latin American NOCs and by NOCs from NRGI's program countries[70]

	Deal value ($ million)	Break-even price +/- A PS ($/bbl)	Break-even price +/- NZE ($/bbl)	Emissions +/- average (CO_2 kg/boe)
Sub-Saharan Africa	4,358	0	27	1
Ghana	207	6	32	N/a
Nigeria	696	21	47	37
Senegal	372	8	36	N/a
Uganda	57	12	39	N/a
Latin America	6,338	6	31	-5
Colombia	3,894	8	35	-18
Mexico	174	-12	15	N/a
Peru	42	-9	18	-11

70 Break-even prices and emission intensities are weighted by transaction value.

Table 5. Average weighted break-even prices per bbl and emission intensities of assets that are part of the top 10 closed sales by sub-Saharan African and Latin American NOCs and by NOCs from NRGI's program countries[71]

	Deal value ($ million)	Break-even price +/- APS ($/bbl)	Break-even price +/- NZE ($/bbl)	Emissions +/- average (CO_2 kg/boe)
Sub-Saharan Africa	2,053	2	29	6
Ghana	12	-7	21	N/a
Nigeria	0	–	–	–
Senegal	0	–	–	–
Uganda	0	–	–	–
Latin America	24,449	-3	24	-1
Colombia	149	86	112	N/a
Mexico	1,920	3	29	11
Peru	0	–	–	–

71 Break-even prices and emission intensities are weighted by transaction value.

GNPC and the Aker controversy

In 2021, the proposal of Ghana's NOC, Ghana National Petroleum Corporation (GNPC), to purchase stakes in the Deep Water Tano/ Cape Three Points (DWT/CTP) block from Aker Energy Ghana and the South Deep Water Tano (SDWT) block from AGM Petroleum Ghana, both subsidiaries of a Norwegian entity, set off a firestorm of controversy. GNPC requested parliamentary approval to enter into a loan of $1.65 billion to finance both the acquisition and GNPC's share of capital expenditure after the acquisition.[72] GNPC's then CEO explained the purchase as part of GNPC's strategy to develop operator capacity as oil majors exit the country.[73]

CSOs strenuously objected to the purchase, arguing that the blocks could not be worth more than $300 million and questioning GNPC's valuation process. They questioned GNPC's long-term oil price assumptions and were concerned that the reserves had not been independently certified.[74] CSOs' sustained objections brought the proposed transaction under public scrutiny.

The transaction was ultimately stymied. CSOs felt vindicated when, 18 months later, AGM proved unable to sell to another company and instead surrendered its interest in the SDWT block back to the government.[75] Aker also sold its interest in the DWT/CTP block to one of its creditors for an upfront payment of only $1 after defaulting on its $200 million loan to develop the block.[76]

At a minimum, the controversy highlights the importance of transparent investment criteria and valuation procedures based on different energy transition scenarios. Such transparency can provide assurance to the public that NOC acquisitions provide good value for money, especially where public money will be used to finance the transaction.

72 See Ben Boakye, "Civic Advocates save Ghana Millions of Dollars as Aker's AGM relinquishes its 80% interest in the South Deepwater Tano Block (SDWT)," *ACEP Africa*, 6 March 2023, www.acep.africa/civic-advocates-save-ghana-millions-of-dollars-as-akers-agm-relinquishes-its-80/.

73 Norvan Reports, "GNPC CEO attributes Aker/AGM acquisition move to fear."

74 Boakye, "Civic Advocates save Ghana Millions."

75 Ibid.

76 "Aker Energy sells its $1.6 billion Ghana oilfield for one dollar," *The Herald*, 26 May 2023, www.theheraldghana.com/23542-2/.

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II. How governments can better manage asset transfers

1. Exercise approval rights to block transfers to unsuitable companies

Governments should use any approval rights they have over asset transfers to vet the quality of potential buyers and block transfers to unsuitable companies.

Many governments have reserved a legal right to approve assignments of interest in upstream petroleum projects, notably under contracts granting companies the right to explore for, and extract, petroleum. Of the 31 English-language petroleum agreements available on ResourceContracts.org signed between 2017 and 2022, all require prior government approval for assignments of interest.[77] Twenty-three of these define "assignment" to include a change of control of the license holder.[78] They would therefore cover transactions in which an IOC sells a controlling interest in its local subsidiary that holds the license or contract in the country. These clauses often include the buyer's sufficient technical and financial competence as a condition for approval of the transfer and require the buyer to accept all the terms and conditions in the assigned contract (27 out of agreements). Most contracts also require licensees to conduct operations in line with best industry practice (27 agreements).

Governments should take the broadest interpretation possible of technical competence and of "best industry practice" to require that buyers have the competence to maintain or exceed the operating standards of the seller and reject applications for approval if not.

Certain minimum emissions management standards should be considered a requirement for best industry practice, given advances in technology and increasing government and company commitments and regulations to reduce emissions from extractive operations.[79] For example, methane makes up half of the greenhouse gas emissions from oil and gas operations.[80] Companies may emit methane by venting or flaring gas or via leaks from pipelines. Methane heats the planet over 80 times more than carbon dioxide over a 20-year period.[81] Therefore, cutting methane emissions in oil and gas operations should be an imperative and is fortunately well within reach.

The IEA estimates that companies can avoid 70 percent of methane emissions using existing technology and can cut almost 45 percent of methane emissions from oil and gas operations at no net cost based on average natural gas prices from 2017 to 2021.[82] At COP28, 50 oil and gas companies, including 30 NOCs, launched an agreement to reduce their Scope 1 and 2 carbon emissions to net zero by 2050 and reduce methane emissions to near zero by 2030.[83]

77 Number of uploaded contracts is as of H1 2023. The 31 contracts include two production licenses from Guyana, which define the terms and conditions for production. ResourceContracts.org is a free online repository of almost 3,000 oil, gas and mining contracts and related documents.

78 The definition for change of control may vary by contract, but generally refers to a change in the entity/entities that control company decision-making. For example, one contract defines "control" as "the ownership of more than fifty percent (50%) of the shares authorised to vote at a general meeting of shareholders, or the ability to pass or procure the passing of a decision (whether by casting of votes or otherwise) at a general meeting of shareholders, or at any meeting of the executive or management body, of the company, venture or enterprise." See Statoil Azerbaijan Ashrafi Dan Ulduzu Aypara BV, SOCAR Oil Affiliate, Ashrafi-Dan Ulduzu-Aypara Area, PSA, 2018, art. 9(2)(c), www.resourcecontracts.org/contract/ocds-591adf-5535899866/view#/pdf.

79 See Davis and Shafaie, *Extracting Emissions*.

80 Deborah Gordon and Sara Herrin, "OCI+ Update: Tackling Methane in the Oil and Gas Sector," *RMI*, 6 April 2023, www.rmi.org/oci-update-tackling-methane-in-the-oil-and-gas-sector/.

81 Ibid.

82 IEA, *Curtailing Methane Emissions from Fossil Fuel Operations: Pathways to a 75% cut by 2030* (March 2022), www.iea.blob.core.windows.net/assets/ba5d143a-f3ab-47e6-b528-049f81eb31ae/CurtailingMethaneEmissionsfromFossilFuelOperations.pdf.

83 *S&P Global Commodity Insights*, "COP28: Fifty oil and gas companies sign net zero, methane pledges," 2 December 2023, www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/120223-cop28-fifty-oil-and-gas-companies-sign-net-zero-methane-pledges.

Governments should similarly take the broadest possible approach to financial competence within the scope of their approval rights. When considering financial competence, governments should consider whether the buyer or seller will be responsible for addressing environmental damage that occurred before the transfer, for decommissioning at the closing of the project, and for community development or CSR projects and contingent liability under pending litigation.[84]

Governments should scrutinize the liabilities buyers will assume under the acquisition and assess whether the buyer has the financial capacity to assume those liabilities. In cases where the seller assigns its interest in a petroleum license or contract, under law or the contract terms, the seller may remain liable for certain obligations unless the buyer explicitly assumes those liabilities.[85] However, if an IOC sells its local subsidiary that holds the interest in the petroleum license/contract, liability may remain with the local company (and therefore will transfer to the buyer of that local subsidiary).[86]

The terms of the asset purchase or assignment agreement, as well as national laws, will determine which liabilities may be transferred to the buyer and any residual liability that remains with the seller.[87] Governments should ensure the assumption of liabilities under the assignment or asset purchase agreement conforms to law and to the capacity of the buyer. Where the buyer's capacities are in doubt, governments should not approve the transfer or should require modifications of the terms on assumption of liabilities to the extent feasible under the government's approval rights.

Governments should also collect and review potential buyers' beneficial ownership information to scrutinize transactions that pose corruption risks and screen out applicants that are ineligible to receive licenses under law. For example, the country's laws may prohibit government officials or their close associates from holding interests in companies applying for extractive sector licenses, to avoid conflicts of interest. Reviewing beneficial ownership details of potential buyers is especially important in cases of transfers to local companies, where the presence of a politically connected beneficial owner may compromise regulators' enforcement of environmental and other operational regulations with respect to that company.[88]

2. Publicly disclose relevant information about transfers

Publicly disclosing information about transfers, including the identity of buyers and sellers, is critical to enable the public to hold both government and companies accountable for ensuring buyers can and will fulfill the obligations they assume after the transfer, including meeting or exceeding the seller's operating standards.

The requirements of the Extractive Industries Transparency Initiative (EITI) can serve as a good starting point for the kind of information most relevant.

84 The risk of inadequate provision for decommissioning is a key concern when it comes to transfers. If IOCs sell to companies with less financial capacity, the risk increases that these buyers will not be able to decommission the project at its closure, leaving governments to foot the bill at taxpayers' expense. See EDF Business and Ceres, *Tackling Transferred Emissions*, which seeks to address this risk and provides that the cost of retirement obligations for the asset should be "fully accounted for at the point of transfer, along with the disclosure of the responsible party's mechanism for assuring those obligations … the holder or holders of the decommissioning liability should be clearly identified at the point of sale … [and] the seller should disclose the estimated non-discounted asset retirement cost, without probability adjustment." See also SDN, *Divesting from the Delta*, on host communities' concerns around pending litigation, environmental cleanup responsibilities and CSR after transfers.

85 For example, two contracts from Timor-Leste of the 31 contracts we reviewed provided that the assignor and assignee remain jointly and severally liable for providing all financial securities in relation to the fulfillment of any unfulfilled accrued obligations of the assignor prior to the effective date of the assignment.

86 Nigerian activists and oil-impacted communities are concerned about whether they can still hold Shell accountable for its legacy oil pollution after the sale of its Nigerian subsidiary, Shell Petroleum Development Company of Nigeria, to a newly established consortium. See Gaughran, Francis & Duruigbo, *Selling out the Niger Delta*.

87 For example, for a discussion of successor liability under U.S. law, see Byron F. Egan, "Asset Acquisitions: Assuming and Avoiding Liabilities," *Penn State Law Review* 116, no. 3 (2012): 913-955, www.pennstatelawreview.org/116/3/116%20Penn%20St.%20L.%20Rev.%20913.pdf.

88 See generally Erica Westenberg and Aaron Sayne, *Beneficial Ownership Screening: Practical Measures to Reduce Corruption Risks in Extractives Licensing* (NRGI, May 2018), www.resourcegovernance.org/sites/default/files/documents/beneficial-ownership-screening_0.pdf.

EITI requires participating countries to disclose the process for transferring licenses; the technical and financial criteria used and any material deviations from such criteria; and information about transferees, including their ultimate beneficial owners.[89]

EITI also requires participating countries to disclose the contracts that provide the terms for exploitation of oil and gas.[90] Ideally, governments should disclose—or require selling companies to disclose—information on transfers before the deal is approved, to allow the public and CSOs to research the reputation and performance of potential buyers and raise issues in advance. For EITI member countries, EITI's requirement to disclose beneficial ownership information for those applying for licenses would imply disclosure of potential buyers' beneficial ownership details before the deal is closed.

Other relevant disclosures should include specifying which party has liability for decommissioning or for pending litigation after the transfer, two issues that are likely to be of concern to host communities. Host communities may also be concerned about what will happen to ongoing community development or CSR projects after the transfer.[91] Where community development is required under law or contract, buyers would also be obliged to contribute to community development.

However, the buyer may not continue specific community development activities pursuant to those obligations (as opposed to starting new projects) or voluntary CSR activities previously carried out by the seller. In any event, governments should ensure that host communities understand the implications of the transfer for the seller's community development activities, whether the buyer will continue them and how these activities will be wound down if the buyer will not continue them.

3. Strengthen laws and regulations on asset transfers, emissions management and decommissioning

Governments will also want to review and strengthen, where appropriate, their legal and regulatory framework to respond to the emerging challenges accompanying divestments and to ensure a consistent minimum standard of practices across companies, regardless of company profile.

While new regulations will apply to new projects, stabilization clauses in contracts between the government and companies for petroleum extraction may limit the application of new regulations to existing projects. Such clauses protect companies against changes in law that occur after the contract is signed. However, stabilization clauses may contain exclusions for changes to environmental, health and safety, labor or other ESG-related laws and may thereby allow governments to apply updated laws to existing projects. Governments should conduct an audit of existing contracts to understand how many projects are protected by stabilization clauses and the scope of the protection. When entering into new contracts, governments should seriously consider avoiding stabilization clauses altogether, or carefully drafting them to ensure they do not prevent them from updating regulation or implementing decarbonization or eventual wind-downs of their petroleum sectors.[92]

Below we identify areas for reviewing and strengthening the regulatory framework, but our list is not exhaustive. Detailed recommendations on the content of regulations for the areas identified are beyond the scope of this briefing, although we indicate helpful resources that governments may consult to develop appropriate regulations.

89 See EITI Standard (2023), Requirements 2.2 and 2.5, www.eiti.org/sites/default/files/2023-06/2023%20EITI%20Standard.pdf.
90 See EITI Standard, Requirement 2.4.
91 See, e.g., SDN, *Divesting from the Delta*.
92 See Nicola Woodroffe, *Tying Their Hands? How Petroleum Contract Terms May Limit Governments' Climate Policy Flexibility* (NRGI, 27 September 2021), www.resourcegovernance.org/publications/tying-their-hands-how-petroleum-contract-terms-may-limit-governments-climate-policy.

Government approval for asset transfers

At a minimum, governments should establish approval rights over transfers—including via a change of control—and specify technical and financial competence to comply with the terms of the contract, law and best industry practice as conditions for approval. Governments should explicitly retain the right to deny approval where the buyer's competence is insufficient. Two of the contracts we reviewed—two production licenses from Guyana—explicitly allow the government to take this approach. They provide that the minister may refuse an application for a transfer if, in his/her opinion, the proposed transferee does not have the same qualifications or capability to do the work as the transferor.[93]

Governments might also consider enhancing the definition of "best industry practice" in future petroleum contracts or regulations to specify that this should be interpreted to include ESG practices.

As the world transitions away from fossil fuels, governments are likely to see more transfers in their territories and should consider an audit of existing laws and contracts. Such an audit should make them aware of where they have approval rights, the scope and limitations of such rights, and the changes they need to make.

Emissions management and reporting

A key issue for governments to consider in evaluating transfers, particularly in the present context of the global energy transition, is the risk of increased emissions intensity in upstream petroleum project operations. This is especially the case when assets go from publicly listed to private companies or from companies with higher environmental management and reporting commitments to those with fewer such commitments. In addition to the negative environmental impacts, countries may soon see a proliferation of carbon prices and other measures imposed on their oil and gas exports by importing countries.

Carbon prices and the share of emissions they cover have increased over the last 10 years, while investors and customers have increased pressure on extractive industries to reduce emissions through initiatives such as Climate Action 100+ and the Glasgow Financial Alliance for Net Zero.[94,95,96] This can impact the competitiveness of projects, and producer countries with high-emissions-intensity projects may see declining investment and narrowing profits (and hence revenues) from these projects.[97] They may also start to face litigation to reduce petroleum sector emissions.[98] It is therefore in producer countries' interest to take measures to reduce emissions intensity from petroleum operations and, even more so, to prevent increases in emissions intensity through declining operational standards.

93 See, e.g., Esso Exploration and Production Guyana Limited, CNOOC Petroleum Guyana Limited, Hess Guyana Exploration Limited, Petroleum Production Licence (2022), 37, www.resourcecontracts.org/contract/ocds-591adf-8840009083/view#. Countries should also ensure adequate oversight and accountability of government officials' decisions and limit discretion where possible. Government officials should provide written reasoned bases for their decisions.

94 Climate Action 100+, www.climateaction100.org/about.

95 Glasgow Financial Alliance for Net Zero, www.gfanzero.com.

96 See Davis and Shafaie, *Extracting Emissions*.

97 Ibid. See also Papa Daouda Diene, Thomas Scurfield and William Davis, *Why Senegal Should Minimize Petroleum Operations Emissions* (NRGI, 7 September 2023), www.resourcegovernance.org/publications/why-senegal-should-minimize-petroleum-operations-emissions; African Development Bank (AfDB), African Natural Resources Management & Investment Centre, *Minimising Greenhouse Gas Emissions in the Petroleum Sector: The Opportunity for Emerging Producers* (October 2022), 9, www.newproducersgroup.online/wp-content/uploads/2022/11/Minimising-Greenhouse-Gas-Emissions-in-the-Petroleum-Sector.pdf.

98 Climate-change-related cases have more than doubled since 2015, according to one study, and have become a tool to push governments to enforce or improve their climate commitments. While most cases identified are from the Global North, there are an increasing number of cases in the Global South. See Joana Setzer and Catherine Higham, *Global trends in climate litigation: 2022 snapshot* (Grantham Research Institute on Climate Change and the Environment, Columbia Law School and Centre for Climate Change Economics and Policy, 2022), www.lse.ac.uk/granthaminstitute/wp-content/uploads/2022/08/Global-trends-in-climate-change-litigation-2022-snapshot.pdf, *Global trends in climate litigation: 2023 snapshot* (Grantham Research Institute on Climate Change and the Environment, Columbia Law School and Centre for Climate Change Economics and Policy, 2023), www.lse.ac.uk/granthaminstitute/wp-content/uploads/2023/06/Global_trends_in_climate_change_litigation_2023_snapshot.pdf. The United Nations Environment Programme has also noted a rapid increase in climate litigation around the world, challenging governments to set new climate goals, issue more stringent climate regulations or even keep fossil fuels in the ground. See United Nations Environment Programme, *Global Climate Litigation Report: 2020 Status Review* (2020), www.wedocs.unep.org/bitstream/handle/20.500.11822/34818/GCLR.pdf?sequence=1&isAllowed=y.

The African Development Bank, Commonwealth Secretariat, and New Producers Group have published valuable guidance for petroleum producers for minimizing emissions in oil and gas production.[99] This guidance can inform governments on the range of possible approaches to regulating emissions, along with key considerations for determining the most suitable approach for the country.[100] The IEA's policies database compiles 450 examples of policies that support methane abatement, while its Regulatory Roadmap and Toolkit provides guidance on both the process for and the content of methane regulations, including prescriptive, performance- or outcome-based, economic or information/reporting-based approaches.[101]

There is also increasing technical assistance available to help countries strengthen emissions management, including the World Bank's Global Flaring and Methane Reduction Partnership,[102] the Global Methane Hub[103] and the United Nations Environment Programme's Climate and Clean Air Coalition.[104]

Regulations may restrict flaring (burning of associated gas), venting (direct release of gas into the atmosphere) or fugitive emissions (leaks of gas such as from pipelines) and prescribe methods and processes for limiting emissions. For example, regulations may require zero routine flaring and outline the conditions under which non-routine flaring is allowed, or require specific technology, types of equipment or standards for leak detection and repair. They may also outline the use or commercialization of associated gas, including reinjection into the reservoir, supply to the local gas market, export or use as feedstock.

They may require use of renewable energy, where feasible, for petroleum operations. Regulations might set emissions reduction targets, focusing on outcomes and allowing companies to determine the methods for meeting those targets. They may also provide financial incentives by imposing taxes on unwanted flaring or venting, forcing companies to internalize the cost of emissions and therefore prompting them to modify their behavior. Regulations should include credible sanctions for non-compliance.

Governments should also ensure that emissions management requirements include monitoring and reporting obligations.[105] Governments will need to decide which regulatory agency will be responsible for designing and enforcing regulations and monitoring compliance and should ensure the agency has adequate resources to fulfill its role. Rules are useless if not properly implemented.[106]

Public disclosure of emissions management will also enhance both company and government accountability. Governments may consider the emerging emissions disclosure rules, such as the EU's Corporate Sustainability Reporting Directive, as a starting point.[107] However, disaggregated disclosures—that is, disclosures of emissions and other environmental management data at the license or project level—will be most relevant to the public and especially host communities, who will want to understand how projects close to or in their communities perform, and what potential financial and environmental risks these projects pose.[108] The EITI Standard encourages greenhouse gas emissions disclosures in line with existing leading disclosure standards, including disaggregated disclosures where feasible.[109]

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99 The New Producers Group is now known as New Producers for Sustainable Energy.
100 See AfDB et al., *Minimising Greenhouse Gas Emissions in the Petroleum Sector.*
101 See IEA, *Driving Down Methane Leaks from the Oil and Gas Industry: A Regulatory Roadmap and Toolkit* (January 2021), www.iea.org/reports/driving-down-methane-leaks-from-the-oil-and-gas-industry.
102 Global Flaring and Methane Reduction Partnership, www.worldbank.org/en/programs/gasflaringreduction/about.
103 Global Methane Hub, www.globalmethanehub.org/.
104 Climate and Clean Air Coalition, www.ccacoalition.org/.
105 The IEA's Regulatory Toolkit, www.iea.org/reports/driving-down-methane-leaks-from-the-oil-and-gas-industry/regulatory-toolkit, provides several examples of reporting requirements under regulations that may serve as a guide.
106 See ibid. and AfDB et al., Minimising Greenhouse Gas Emissions in the Petroleum Sector.
107 See Part I, "Asset transfer trends and challenges."
108 See Daniel Kaufmann and Robert Pitman, "Extractive Company Disclosure of Project-Level Greenhouse Gas Emissions in Critical," NRGI, 1 May 2023, www.resourcegovernance.org/articles/extractive-company-disclosure-project-level-greenhouse-gas-emissions-critical.
109 See EITI Standard (2023), Requirement 3.4, www.eiti.org/sites/default/files/2023-06/2023%20EITI%20Standard.pdf.

Decommissioning funding

Decommissioning involves the cleanup and restoration of a site when operations are ended, including the plugging and abandonment of wells, cleaning of facilities to remove hazardous materials, dismantling, and removal and disposal of physical structures. Decommissioning takes place at the end of the life of a project at a point when net cash flows are negative—the costs of continued operations are greater than revenues, and it is therefore not commercially feasible to continue operations. Decommissioning can be expensive, and without sufficient revenues from the project, there is a risk that the operating company or companies will not have the financial resources to undertake decommissioning when the time comes. In that event, the government, taxpayers and the public will have to pay for decommissioning or suffer the environmental and public health hazards of an improperly decommissioned site.[110] Ensuring adequate financing for decommissioning well in advance is therefore essential.[111]

Such financial assurance may take various forms. These include bank letters of credit, parent company guarantees, surety bonds (in which a third-party bank, parent company or insurance company promises to pay for the decommissioning costs if the company does not do so), and decommissioning funds into which the company is required to incrementally set aside money during the life of the project to cover decommissioning costs at the end of production.[112]

Where IOCs sell assets to smaller, less diversified or less financially able companies, the government is more exposed to the risk that the new operator will be unable to cover decommissioning costs at the end of the project.

The nature of the financial assurance provided by the previous owner, if any, will determine whether financial assurance is easily transferrable to the new owner. Financial assurance such as parent guarantees or letters of credit that are specific to the company that obtained the guarantee will not be transferrable, whereas a decommissioning fund set up for the project will remain with the project after the transfer.

Of the 31 contracts we reviewed, all required the company to set up a decommissioning fund. However, the contract provisions varied widely on timing for setting up such a fund. Some contracts required the company to begin quarterly or annual contributions to the fund very early in the life of the project, from the start of commercial production or even the first date of commercial discovery. Others ranged from the fourth anniversary of commercial production to the earlier of the fifteenth anniversary of the start of the development and production period or the calendar quarter in which 70 percent of reserves have been recovered. This means that assets might be transferred before any funds have been deposited, and adequate provision for decommissioning will hinge entirely on future cash flows from the project and on the buyer continuing to successfully operate the project. Yet the risk of bankruptcy among smaller companies with fewer financial resources is higher than for IOCs.[113]

Moreover, the present value of decommissioning costs and the amount and timing of contributions to a decommissioning fund are based on assumptions about how long the project will operate; that is, how long net cash flows will remain positive. An accelerated energy transition could require decommissioning sooner than expected, as drops in long-term pricing or regulatory measures mean projects become commercially unviable sooner.[114]

110 Including contaminated water sources and soil, damaging prospects for alternative uses and other economic activity such as fishing or agriculture in the project area.

111 See generally Naadira Ogeer, *Oil and Gas Decommissioning Toolkit: Practical Guidance for Governments* (The Commonwealth, 2022), www.thecommonwealth-ilibrary.org/index.php/comsec/catalog/book/1078, for a detailed treatment of the various considerations for developing appropriate decommissioning regulations.

112 Ibid. See also Martin Lockman, Martin Dietrich Brauch, Esteban F. Fresno Rodríguez and José Luis Gallardo Torres, *Decommissioning Liability at the End of Offshore Oil and Gas: A Review of International Obligations, National Laws, and Contractual Approaches in Ten Jurisdictions* (Columbia Center on Sustainable Investment, 2023), 22-31, www.ccsi.columbia.edu/sites/default/files/content/docs/Sabin-Center-CCSI-decommissioning-liability-offshore-oil-gas.pdf.

113 See generally Robert Schuwerk and Greg Rogers, *Billion Dollar Orphans: Why millions of oil and gas wells could become wards of the state* (Carbon Tracker Initiative, October 2020), www.carbontracker.org/reports/billion-dollar-orphans/.

114 See Ogeer, *Oil and Gas Decommissioning Toolkit*, 20-23.

Some contracts required annual revisions to decommissioning plans, while others required updates every five or 10 years. A combination of contributions to a decommissioning fund late in the life of the project and infrequent updates to the schedule and estimated cost of decommissioning will increase the risk that the funds accumulated will be insufficient to cover decommissioning costs when they are needed.

When NOCs acquire assets, and when companies surrender assets to the state with insufficient or no decommissioning funds, the state directly takes on the future costs of decommissioning.

State decommissioning options

Governments can consider different options, or a combination thereof, to protect themselves from the risk of inadequate decommissioning funds in general, and particularly after a transfer.

First, governments should strongly consider requiring all companies to set up decommissioning funds where this requirement does not already exist, with contributions to the fund commencing, at the latest, as soon as the project begins to generate revenues.[115] For example, Nigeria's latest decommissioning regulations require companies to set up a decommissioning fund no later than 90 days from the date of commencement of production for new licenses and 90 days from the date of commencement of the regulations for existing licenses.[116] Regulations should require companies to regularly review and update decommissioning plans as necessary, taking into consideration the latest energy transition scenarios.[117]

Second, governments should consider requiring transfer of full costs of decommissioning to the decommissioning fund for transfers (or surrenders back to the state) that take place late in the life of an asset.

For example, Carbon Tracker Initiative recommends using standard cash flow analysis to determine the point at which decommissioning liability exceeds future net cash flows; at this point, all future cash flows would need to be "held back" to cover decommissioning costs.[118] The timing of this point will also be based on whether a decommissioning fund for the project has already been established and the current balance in the fund at the time of transfer.

For example, three of the contracts (all from Azerbaijan) capture this concept, albeit with respect to relinquishments or termination of the contract at any stage of the project and with a cap on costs. They provide that, on termination of the agreement or relinquishment of the entire area covered by the contract, the company must pay an amount equal to the difference between the lesser of the total then estimated costs of decommissioning and 10 percent of all capital costs attributable to the area from the effective date of the contract up to the date of notice of relinquishment or termination, and contributions already made by the company to an abandonment fund.[119]

115 See also Martin Dietrich Brauch, Esteban F. Fresno Rodríguez and José Luis Gallardo Torres, *Provisions on Liability for Decommissioning Upstream Offshore Oil and Gas Infrastructure in Investor–State Contracts* (Columbia Center on Sustainable Investment, 2023), 14-15, www.ccsi.columbia.edu/sites/default/files/content/docs/ccsi-decommissioning-offshore-oil-gas-infrastructure-investor-state-contracts.pdf, which recommends that contributions begin before project construction.

116 See Nigeria Upstream Petroleum Decommissioning and Abandonment Regulations, 2023, www.nuprc.gov.ng/wp-content/uploads/2023/07/DECOMMISSIONING-REGULATIONS.pdf.

117 See also Lockman, Dietrich Brauch, Fresno Rodríguez and Gallardo Torres, *Decommissioning Liability at the End of Offshore Oil and Gas*, 40.

118 See Dwayne Purvis and Rob Schuwerk, *Event Horizon: A Case Study of Holdback and the Point of No Return for Decommissioning Upstream Oil and Gas "Assets"* (Carbon Tracker Initiative, July 2022), www.carbontracker.org/reports/event-horizon-a-case-study-of-holdback-analysis/.

119 See, e.g., Statoil Azerbaijan Ashrafi Dan Ulduzu Aypara BV, SOCAR Oil Affiliate, Ashrafi-Dan Ulduzu-Aypara Area, PSA, 2018, art. 14(2)(j)-(k), www.resourcecontracts.org/contract/ocds-591adf-5535899866/view#/pdf.

Third, governments can implement joint and several liability for decommissioning not only for current operators of the project or asset but all previous owners, meaning governments can require any past or present owners to fulfill any or all decommissioning obligations. This may provide some protection for the government against companies with more financial resources transferring assets to companies with less financial capacity that then prove unable to carry out decommissioning. In the U.S., the Department of the Interior can hold previous operators liable for decommissioning if the current owner is unable to cover the costs.[120]

In the U.K., previous owners may also be held liable for decommissioning at least of infrastructure that was in place at the time of the transfer.[121] On liability for environmental pollution under the previous owner, governments should disallow transfer of such liability to new owners and/or extend joint and several liability to previous owners that held the asset when the pollution took place.

Fourth, governments should ensure that a company's decommissioning liabilities have super-priority in bankruptcy proceedings over other claims. For example, under U.S. bankruptcy law, decommissioning obligations are categorized as "administrative expense" claims and take priority over all other unsecured claims in a bankruptcy proceeding.[122] Such priority will at least ensure that, in the event a current owner files for bankruptcy, decommissioning obligations will be paid first.

4. Ensure public scrutiny of noc acquisitions

As noted above, a key issue in evaluating NOC acquisitions is whether these are a prudent use of public funds and likely to be profitable. Prior NRGI research has found that a quarter of NOCs' planned investment to develop and expand upstream oil and gas projects over the next 10 years will prove unprofitable if governments implement all their climate pledges and consequently oil demand falls.[123] At the same time, government and NOCs are less financially capable of bearing these risks; government and NOC debt are rising in some regions, including sub-Saharan Africa and Latin America.[124] NOC acquisitions—whether through a purchase or a relinquishment—have the potential to add to these risks to public finances.

Governments must evaluate the opportunity cost of using public funds for NOC purchases when compared with other spending priorities.[125] But even NOC acquisitions resulting from relinquishments in which money does not change hands should be assessed for transition risks using the tools we have recommended for scrutinizing NOC investment plans for development and expansion of upstream projects. NOCs and their governments should acknowledge transition risks, assess how exposed investments are to transition risk and act to mitigate these risks.[126]

120 See Christopher M. Matthews, "Oil Companies Are Ordered to Help Cover $7.2 Billion Cleanup Bill in Gulf of Mexico," *Wall Street Journal*, 6 July 2021, www.wsj.com/articles/oil-companies-are-ordered-to-help-cover-7-2-billion-cleanup-bill-in-gulf-of-mexico-11625569200.

121 But possibly not any installations added after the transfer. See Allister Thomas, "Exxon loses to Apache in high Court battle on £100m decommissioning bill," *Energy Voice*, 25 May 2021, www.energyvoice.com/oilandgas/north-sea/decom/324754/exxon-apache-decommissioning-court/. See also John Paterson, "Apache-Exxon decom case: Is the regulator left without options? Not necessarily," *Energy Voice*, 25 May 2021, www.energyvoice.com/opinion/324841/apache-exxon-decommissioning-john-paterson-aberdeen-uni/.

122 See David L. Curry Jr and Ryan A. O'Connor, "Unplugging the Fifth Circuit's Abandonment Problem: A Reexamination of the Midlantic Exception in Offshore E&P Cases," *Tulane Environmental Law Journal* 31, Issue 1 (Winter 2017), www.jstor.org/stable/90018761.

123 See Part I, page 22. See generally Manley, Furnaro and Heller, *Riskier Bets, Smaller Pockets*.

124 Ibid.

125 See Diop, Daouda Diene and Shafaie, "Between Delays and BP's Exit," with respect to plans for Petrosen to increase participation in the Yakaar-Teranga project.

126 See Manley, Furnaro and Heller, *Riskier Bets, Smaller Pockets*, for a full discussion of our recommendations on how governments and NOCs can manage NOC risk exposure in their investments in upstream petroleum assets.

In addition, governments should hold NOC acquisitions up to public scrutiny. Governments should require NOCs to disclose relevant information on their acquisition decisions. The EITI Standard can again serve as a guide to producer countries whether they participate in EITI or not. EITI countries are expected to provide at least *post hoc* transparency around state-owned extractive companies' acquisitions including terms of the transaction and details regarding valuation and revenues.[127] NOCs are also encouraged to disclose how their investments are aligned with energy transition and climate risk considerations.[128]

However, transparency *before* transactions are completed will allow civil society, affected communities and the general public to raise concerns in advance. Governments should therefore require NOCs to disclose investment plans, including criteria for acquisitions, taking into account energy transition and climate risks and details regarding planned acquisitions, including the value of the asset, the valuation method the government used to determine the value and the projected capital expenditure required for the project after acquisition. The source(s) of financing for the acquisition should also be disclosed to allow the public to understand to what extent public money is being put at risk for the acquisition.

A critical component for assessing value and risk is estimated decommissioning costs. Governments should require their NOCs to disclose information that helps the public to understand the NOC's outstanding decommissioning liabilities. This should include the estimated decommissioning costs associated with a planned acquisition and what portion is already covered by balances in any decommissioning fund associated with the asset.

Conclusion

As the world journeys towards a future beyond oil and gas, oil and gas assets will continue to change hands, with different kinds of companies filling the gap left behind by others. An increasing role in the oil and gas sector for private companies, local companies and local NOCs creates both opportunities and risks for producer countries. Governments have an important role to play in regulating asset transfers to ensure high operating standards in their petroleum sectors, to protect against negative impacts on the environment and communities, and to ensure that NOCs' acquisitions are strategic rather than opportunistic.

127 See EITI Standard (2023), Requirement 2.6, www.eiti.org/eiti-requirements.
128 Ibid.

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