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Analysis of Upstream Oil and Gas Asset Structure and Cost–Benefit Benchmarking for International Oil Companies

Guifang Fa *, Zuoqian Wang, Yanjing Yi and Jun Yin

Research Institute of Petroleum Exploration & Development, PetroChina, Beijing 100083, China; wangzuoqian@petrochina.com.cn (Z.W.); yiyanjing@petrochina.com.cn (Y.Y.); yj96@petrochina.com.cn (J.Y.)
* Correspondence: fafang@petrochina.com.cn

Abstract

This study conducts an in-depth analysis of the disparities in upstream oil and gas asset scale and cost–benefit performance between PetroChina and major international oil companies. By comparing core indicators, including oil and gas asset distribution, reserves, production scale and structural changes, cost management capacity, profitability, and return on investment over the past five years among PetroChina and seven mainstream international oil corporations, namely ExxonMobil, Shell, BP, Chevron, TotalEnergies, Equinor, and Eni, this paper identifies the competitive strengths and weaknesses of PetroChina in the global energy market. The research question is: what is PetroChina's competitive position relative to IOCs across three dimensions—asset scale, cost–benefit performance, and strategic management—and what is the nature and magnitude of the gaps, and what are the actionable pathways for improvement? PetroChina and the seven benchmark companies are all SEC-reporting firms and cover both U.S. and European IOC models, ensuring comparability of reserve and financial data. The results show that PetroChina holds a clear advantage in overall asset scale, while a notable gap remains in cost control and capital investment returns compared with peer international enterprises. This gap is particularly pronounced in exploration expenditure, but is partly attributable to geological endowment and investment timing rather than operational efficiency alone. Accordingly, targeted strategies are proposed to optimize its asset portfolio, promote technological innovation, improve capital allocation efficiency, and accelerate the low-carbon energy transition, so as to enhance its global competitive edge. This research can provide reliable references for the internationalization layout and strategic decision-making of Chinese petroleum enterprises.

Keywords: upstream oil and gas assets; scale and profitability; benchmarking analysis; PetroChina; IOCs

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1. Introduction

The profound restructuring of the global energy system has made the scale and economic efficiency of upstream oil and gas assets core yardsticks for evaluating the comprehensive competitiveness of oil and gas enterprises. Amid an accelerating energy transition and intensifying cross-border market competition, PetroChina (Beijing, China), as China's leading national oil company, faces both notable opportunities and severe challenges in its overseas expansion and global strategic layout [1,2].

Benchmarking, as a strategic analytical tool, uses peer best practice or peer averages as a reference to identify a target firm's position and performance gaps along key dimensions, and to derive improvement directions accordingly. The approach has been increasingly

applied in the energy sector: Månsson et al. (2025) examine its implications for practice and policy [3], while Szydelko and Rokita (2024) demonstrate financial benchmarking using Polish energy-sector companies as a case [4]. Existing benchmarking studies of oil companies, however, tend to be confined to specific functional domains. Studies have, for instance, conducted benchmarking analyses of exploration efficiency and exploration management, as well as of financial management, yet these analyses remain limited in scope—typically addressing a single dimension of performance rather than the firm as a whole [5–8]. They seldom integrate asset scale, reserve structure, cost composition, and strategic orientation into a coherent framework. Such domain-specific analyses reveal localized differences but cannot portray a firm's overall competitive position. The contribution of this paper therefore lies in constructing a three-tier progressive benchmarking framework—asset scale, cost–benefit, and strategic management—that combines quantitative indicator comparison with strategic-orientation analysis, thereby offering a more comprehensive diagnostic of competitive positioning than single-dimensional evaluations.

The research framework is presented in Figure 1. It comprises four progressive modules: asset scale and structure (Section 2.1), production scale and structure (Section 2.2), cost–benefit performance (Section 3), and strategic management (Section 4). The specific benchmarking indicators evaluated in each module are listed in the corresponding column. Data sources are differentiated by module: Section 2.1 draws on SEC annual reports, compiled by the authors; Section 3 uses standardized financial indicators from the S&P Energy Portal, which are also based on SEC annual reports; Section 2.2 uses Rystad Energy's equity production data, which cover the full perimeter (including non-listed assets); and Section 4 relies on public disclosures and industry reports. Quantitative findings from the first three modules inform the strategic analysis in Section 4, and all dimensions converge into the integrated gap identification and discussion in Section 5.

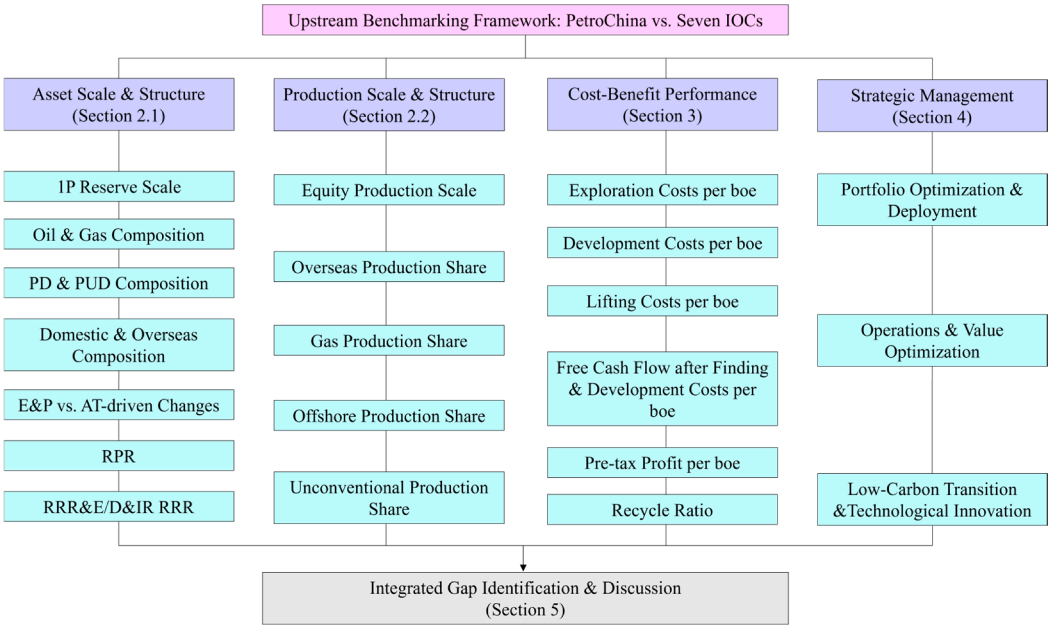


Figure 1. Research framework and benchmarking dimensions of the study.

Accordingly, this paper addresses three questions: What is PetroChina's competitive position relative to major IOCs in terms of asset scale, cost–benefit performance, and strategic management? What is the nature and magnitude of the gaps? And what are the actionable pathways for improvement?

To address these questions, the study combines quantitative statistics with qualitative comparative analysis. Using five years of data from company annual reports, Rystad Energy, and S&P Energy Portal, it compares PetroChina with seven leading IOCs across asset distribution, oil and gas reserves, production scale and structure, cost management, profitability, and return on investment, thereby providing an objective assessment of PetroChina's overall competitive position. The three sources are used as complements, a choice that involves a deliberate trade-off.

2. Benchmarking Analysis of Upstream Asset Scale: PetroChina vs. IOCs

This section compares upstream asset scale between PetroChina and seven IOCs, all of which disclose annual reports under SEC rules. The two subsections rely on different data sources, and this difference should be noted at the outset. Section 2.1 uses reserve data disclosed in company annual reports only. Section 2.2 uses equity production data from Rystad Energy, which offers full-perimeter coverage and a finer classification of production than annual reports, but these data cannot be directly reconciled with the annual-report reserve data in Section 2.1.

2.1. Reserve Scale and Composition

Endowed with a dominant domestic market position and extensive overseas layout, PetroChina holds a massive foundation of oil and gas resources. By the end of 2024, the company's proved reserves (1P) amounted to 18,552 million barrels of oil equivalent (MMboe), ranking second only to ExxonMobil (Spring, TX, USA) and far exceeding those of other IOCs. Here, 1P refers to SEC proved reserves, comprising proved developed (PD) and proved undeveloped (PUD) reserves.

In terms of reserve composition, however, PetroChina's reserves remain dominated by conventional oil and gas fields, with a relatively low share of unconventional resources. This differs from the prevailing development trend among major IOCs, which in recent years have vigorously expanded into unconventional domains such as shale oil and gas, as well as into deepwater oil and gas resources [9–12].

2.1.1. Reserve Scale Analysis

The 1P reserves distribution among the eight oil companies in 2024 exhibits significant heterogeneity and a distinct three-tier hierarchy (Figure 2). ExxonMobil (19,949 MMboe) and PetroChina (18,552 MMboe) constitute the first tier, with reserves exceeding 18,000 MMboe. The second tier comprises TotalEnergies (Courbevoie, France; 11,073 MMboe), Chevron (San Ramon, CA, USA; 9804 MMboe), and Shell (London, UK; 9620 MMboe), with reserves ranging from 9000 to 11,000 MMboe. The third tier consists of Eni (Rome, Italy; 6497 MMboe), BP (London, UK; 6248 MMboe), and Equinor (Stavanger, Norway; 5571 MMboe), with reserves ranging from 5500 to 6500 MMboe.

Analysis of 1P reserve dynamics over 2020–2024 shows that the five-year average growth volume and average growth rate were negative for all eight companies (Table A1). Individual years nevertheless differ: PetroChina, ExxonMobil, Shell, and Equinor recorded net increases in some years, but these were not enough to offset declines in other years, so their five-year averages remain negative. Three patterns emerge:

- Radical depletion. BP registers an average annual reduction of 2619 MMboe, corresponding to an average annual growth rate of −16.77%, reflecting the impact of its aggressive energy transition strategy on conventional oil and gas assets;
- Moderate decline. Chevron (annual average decrease of 325 MMboe, −2.92%), Shell (−295 MMboe, −2.48%), TotalEnergies (−321 MMboe, −2.39%), and Eni (−154 MMboe, −2.19%) maintain relatively stable reserve bases through asset optimization;

- Relative stability. PetroChina (annual average decrease of 352 MMboe, −1.68%), Equinor (−86 MMboe, −1.27%), and ExxonMobil (−499 MMboe, −0.28%) exhibit relatively strong reserve stability, with annual decline rates within −2.00%.

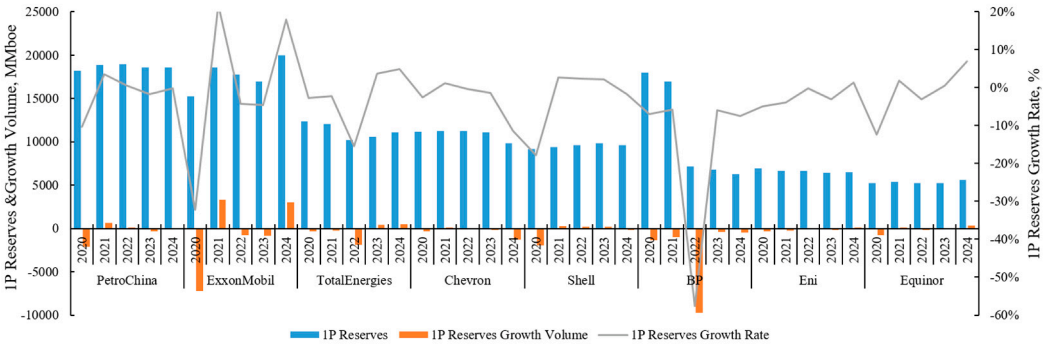


Figure 2. 1P reserves, annual growth volume, and annual growth rate of eight oil companies (2020–2024). Data source: company annual reports, compiled by the authors.

This differential evolution mirrors the strategic orientations of the companies during the energy transition. Proactive transformers, represented by BP, have scaled down conventional operations and divested legacy fossil-fuel assets, leading to a sharp contraction of reserves. In contrast, stability-oriented players such as ExxonMobil and PetroChina adhere to a conservative resource development pathway, reinforcing their reserve bases through exploration and production technology innovation, portfolio optimization, and diversified asset allocation. PetroChina's five-year average decline (−1.68%) was milder than the eight-company average (−3.75%), indicating relatively greater reserve stability.

2.1.2. Reserve Composition Analysis

Analysis of SEC reserve data for 2020–2024 (see Table A2) reveals pronounced structural differentiation among the eight oil companies (see Figure A1).

In terms of hydrocarbon composition, ExxonMobil leads the industry with average annual crude oil reserves of 11,481 MMboe, while PetroChina exhibits a distinctive low-carbon energy structure advantage, with natural gas accounting for 66.77% of its total reserves on a five-year average basis. Notably, the reserve evolution pathways of these companies can be classified into three typical patterns:

- Dual Decline Type, characterized by concurrent reductions in both oil and gas reserves, exemplified by Chevron and BP—the latter experiencing a dramatic 57.63% (declined from 16,954 MMboe in 2021 to 7184 MMboe in 2022) contraction in total reserves due to the divestment of Russian assets following the Russia–Ukraine conflict;
- Structural Growth Type, where ExxonMobil and PetroChina achieved total reserve growth through crude oil expansion (54.09% and 17.02%, respectively), while Shell and Equinor achieved total reserve growth through natural gas expansion (10.84% and 9.60%, respectively);
- Strategic Adjustment Type, represented by TotalEnergies, which reduced its natural gas reserves by 21.93%, indicating a shift in strategic focus.

The structural characteristics of PD and PUD reserves reveal the growth potential of these companies. In terms of PD and PUD composition, ExxonMobil and PetroChina held substantial PUD reserves, averaging 6294 MMboe and 6296 MMboe, respectively, over the five-year study period. This similarity in PUD scale may indicate comparable medium- and long-term development potential. Shell and Eni have actively optimized their reserve structures, achieving remarkable PUD growth of 103.32% and 39.00%, respectively, thereby effectively mitigating the impact of declining PD reserves.

From an internationalization perspective, European companies such as TotalEnergies and BP maintain overseas reserve shares exceeding 90%, whereas PetroChina, driven by its mandate to ensure domestic supply security, retains a predominantly home-country-oriented asset structure, with overseas reserves accounting for only 6.78% on a five-year average basis. U.S. oil companies exhibit a pronounced "domestic reshoring" trend: ExxonMobil and Chevron have reduced their overseas reserve shares by 6.80 percentage points (from 65.77% in 2020 to 58.97% in 2024) and 13.65 percentage points (from 72.59% to 58.94%), respectively, actively contracting overseas assets in high-geopolitical-risk regions while intensifying exploration and development in North America [13]. These shifts reflect different national attributes and development priorities, with companies adjusting overseas portfolios as geopolitical complexity and energy-security requirements increase.

2.1.3. Reserve Change Typology Analysis

As disclosed in the SEC annual filings, annual changes in 1P reserves comprise six categories: extensions and discoveries, improved recovery, revisions (including positive and negative revisions), production, purchases, and sales. Analysis of the 2020–2024 period (Table 1, Figure 3) reveals that these changes are predominantly driven by two modes: exploration and production (E&P)-driven, which encompasses extensions and discoveries, improved recovery, revisions, and production; and asset transaction (AT)-driven, which consists of purchases and sales.

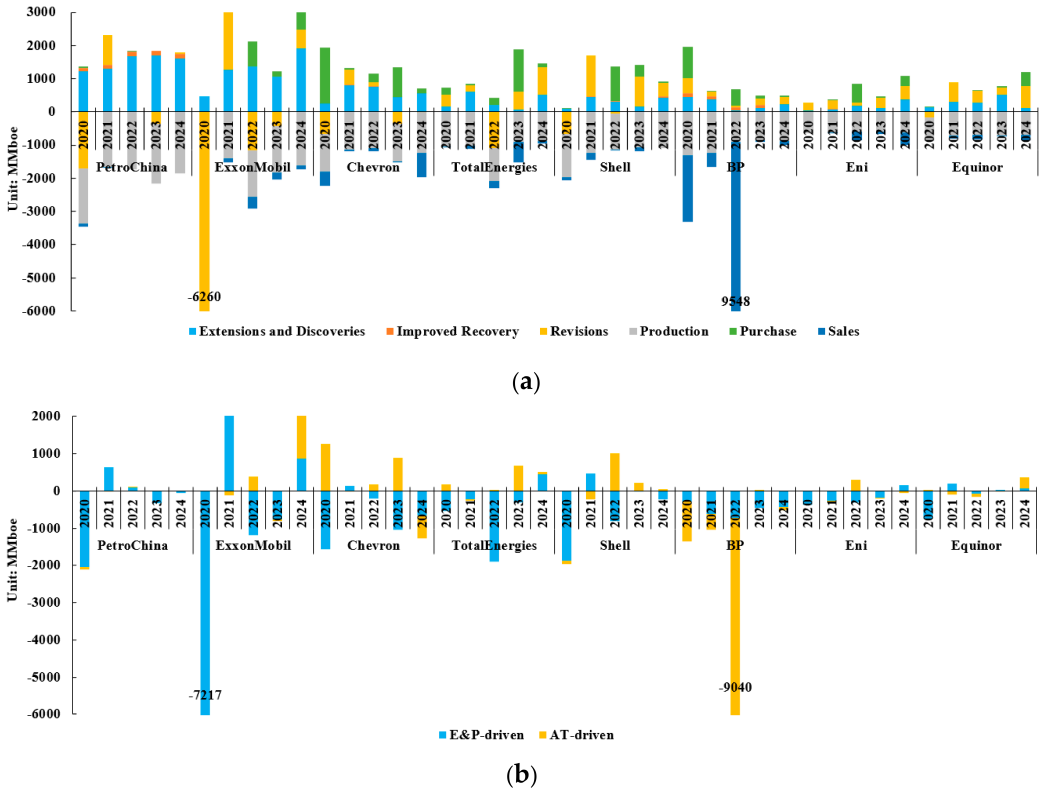


Figure 3. (**a**) Six categories of annual 1P reserve changes for eight oil companies (2020–2024); (**b**) annual E&P-driven and AT-driven 1P reserves changes for eight oil companies (2020–2024). Data source: company annual reports, compiled by the authors.

Table 1. Classification of proved reserves annual changes for eight oil companies (2020–2024, Unit: MMboe).

Company	Classification of Proved Reserves Annual Changes		2020	2021	2022	2023	2024
PetroChina	E&P-driven	Extensions and Discoveries	1215	1303	1663	1695	1602
		Improved Recovery	108	121	147	141	143
		Revisions	−1712	884	0	−355	50
		Production	−1660	−1664	−1728	−1804	−1846
		Subtotal	−2050	645	81	−322	−51
	AT-driven	Purchase	33	0	2	0	0
		Sales	−93	−3	0	0	0
		Subtotal	−60	−3	2	0	0
	Total Annual Change		−2110	642	82	−322	−51
ExxonMobil	E&P-driven	Extensions and Discoveries	459	1272	1376	1065	1915
		Improved Recovery	0	2	0	0	0
		Revisions	−6260	3572	−1157	−429	567
		Production	−1416	−1393	−1402	−1402	−1619
		Subtotal	−7217	3453	−1183	−766	863
	AT-driven	Purchase	0	6	745	159	2281
		Sales	−17	−134	−356	−207	−123
		Subtotal	−17	−128	389	−48	2158
	Total Annual Change		−7234	3325	−794	−814	3021
Chevron	E&P-driven	Extensions and Discoveries	247	807	754	441	551
		Improved Recovery	2	9	26	11	11
		Revisions	−678	450	107	−351	−12
		Production	−1129	−1131	−1096	−1139	−1221
		Subtotal	−1558	135	−209	−1038	−671
	AT-driven	Purchase	1691	43	270	880	143
		Sales	−430	−48	−96	−2	−737
		Subtotal	1261	−5	174	878	−594
	Total Annual Change		−297	130	−35	−160	−1265
TotalEnergies	E&P-driven	Extensions and Discoveries	151	620	205	70	512
		Improved Recovery	0	0	0	0	0
		Revisions	362	184	−1090	538	830
		Production	−1051	−1029	−1008	−906	−891
		Subtotal	−538	−225	−1893	−298	451
	AT-driven	Purchase	206	53	224	1281	116
		Sales	−21	−94	−202	−609	−58
		Subtotal	185	−41	22	672	58
	Total Annual Change		−353	−266	−1871	374	509
Shell	E&P-driven	Extensions and Discoveries	89	432	298	160	420
		Improved Recovery	0	32	32	3	49
		Revisions	−678	1237	−45	888	402
		Production	−1287	−1229	−1090	−1065	−1084
		Subtotal	−1876	472	−805	−14	−213
	AT-driven	Purchase	8	0	1029	357	46
		Sales	−103	−231	−10	−134	0
		Subtotal	−95	−231	1019	223	46
	Total Annual Change		−1971	241	214	209	−167

Table 1. *Cont.*

Company	Classification of Proved Reserves Annual Changes		2020	2021	2022	2023	2024
BP	E&P-driven	Extensions and Discoveries	436	361	49	107	236
		Improved Recovery	133	100	84	109	3
		Revisions	437	146	47	191	200
		Production	−1295	−1230	−911	−861	−881
		Subtotal	−289	−623	−731	−454	−442
	AT-driven	Purchase	954	14	508	84	57
		Sales	−2023	−421	−9548	−53	−129
		Subtotal	−1069	−407	−9040	31	−72
	Total Annual Change		−1358	−1030	−9771	−423	−514
Eni	E&P-driven	Extensions and Discoveries	47	69	179	104	367
		Improved Recovery	5	12	10	0	1
		Revisions	219	259	89	312	406
		Production	−634	−614	−588	−604	−625
		Subtotal	−363	−274	−310	−188	149
	AT-driven	Purchase	0	1	573	47	319
		Sales	0	−5	−277	−59	−385
		Subtotal	0	−4	296	−12	−66
	Total Annual Change		−363	−278	−14	−200	83
Equinor	E&P-driven	Extensions and Discoveries	131	306	278	507	123
		Improved Recovery	0	0	0	0	0
		Revisions	−171	596	344	232	650
		Production	−710	−710	−695	−711	−699
		Subtotal	−750	192	−73	28	74
	AT-driven	Purchase	6	0	36	31	435
		Sales	0	−96	−128	−35	−151
		Subtotal	6	−96	−92	−4	284
	Total Annual Change		−744	96	−165	24	358

Data source: company annual reports, compiled by the authors.

In terms of exploration and development, the E&P-driven subtotal (extensions and discoveries, improved recovery, and revisions, net of production) was negative on a five-year cumulative basis for all eight companies, indicating that, over the period as a whole, exploration and development activity alone did not fully offset production. The magnitude of the shortfall nevertheless differed markedly: ExxonMobil recorded the largest average annual E&P-driven deficit (−970 MMboe), followed by Chevron (−668 MMboe), BP (−508 MMboe), TotalEnergies (−501 MMboe), and Shell (−487 MMboe), whereas Eni (−197 MMboe) and Equinor (−106 MMboe) recorded the smallest deficits and PetroChina (−339 MMboe) occupied an intermediate position. These deficits were persistent across the period rather than incurred uniformly every year, as positive E&P-driven replacement occurred in several companies in individual years—for example, PetroChina in 2021 (+645 MMboe), Shell in 2021 (+472 MMboe), TotalEnergies in 2024 (+451 MMboe), Eni in 2024 (+149 MMboe), and Equinor in 2021, 2023, and 2024 (+192, +28, and +74 MMboe, respectively). ExxonMobil illustrates this year-to-year volatility most clearly: its 2020 result was dominated by a 6260 MMboe negative revision, driven primarily by the exceptionally low oil prices that year, under which substantial U.S. volumes—together with Canadian bitumen resources—no longer qualified as proved reserves under the SEC definition, and compounded by the company's near-term reduction in capital expenditure; in sharp contrast, its 2024 E&P-driven result (+863 MMboe) was underpinned by 1915 MMboe of extensions and discoveries,

mainly in the U.S. and Guyana, and 567 MMboe of positive revisions in the UAE, U.S., and Canada.

Regarding asset transactions, IOCs exhibited active portfolio optimization strategies. On a five-year average basis, ExxonMobil (+471 MMboe), Chevron (+343 MMboe), Shell (+192 MMboe), TotalEnergies (+179 MMboe), Eni (+43 MMboe), and Equinor (+20 MMboe) all recorded net positive transaction-driven reserve changes, reflecting intensive acquisition activity. BP, by contrast, reported an average annual net reduction of 2111 MMboe, dominated by the 9548 MMboe of sales in 2022 associated with its withdrawal from Russian assets, consistent with its strategic transition. PetroChina adopted a distinctly conservative approach to asset transactions, with activity limited and concentrated in 2020–2022, resulting in an average annual net decrease of 12 MMboe. This contrast reflects a clear divergence in asset management strategies between national oil companies and their international counterparts: IOCs leverage high-frequency asset transactions to rapidly reconfigure their portfolios, whereas PetroChina prioritizes endogenous growth and incremental portfolio optimization.

2.1.4. Reserve Potential Evaluation

The Reserve-to-Production Ratio (RPR) is defined as the ratio of year-end reserves to annual production [14,15], reflecting the overall exploration and development status of an oil company. A high RPR suggests a large reserve inventory that may hinder rapid resource conversion, whereas a low RPR indicates insufficient reserves and weak production assurance. The Reserve Replacement Ratio (RRR) is calculated as the ratio of total reserve additions (including extensions and discoveries, improved recovery, net purchases, and revisions) to production [16–18]. An RRR ≥ 1 indicates that reserve additions fully replace production; $0 \leq$ RRR < 1 indicates positive reserve additions that are nevertheless insufficient to replace production; and RRR < 0 indicates that reserve additions are negative. Both RPR and RRR are annual cross-sectional indicators that do not measure multi-year growth, and together they serve as two core indicators of an oil company's sustainable development potential.

Analysis of SEC 1P oil-equivalent RPR trends from 2020 to 2024 (see Table A3) reveals three distinct patterns among the eight oil companies:

Continuous decline—exemplified by BP (13.89 → 7.09), PetroChina (11.04 → 10.19), and Chevron (9.86 → 8.03), with BP exhibiting the most pronounced decrease; Stable maintenance—observed in Eni (10.89–10.40) and Equinor (7.41–7.97); Progressive improvement—displayed by Shell (7.09 → 8.87), TotalEnergies (11.73 → 12.43), and ExxonMobil (10.74 → 12.32).

Notably, although PetroChina's RPR declined from 11.04 to 10.19, it remained above the sample average level of 10.00.

The SEC 1P oil-equivalent RRR trends from 2020 to 2024 (Figure 4) show differentiated development among IOCs. In 2024, ExxonMobil (2.87), TotalEnergies (1.57), Equinor (1.51), and Eni (1.13) recorded RRR ≥ 1, whereas PetroChina (0.98), Shell (0.85) and BP (0.42) recorded $0 \leq$ RRR < 1, and Chevron (-0.04) recorded RRR < 0, indicating net reserve reductions in that year. On a five-year average basis, Equinor (0.88), PetroChina (0.80), and Shell (0.78) came closest to unity but remained below 1, while BP (-1.74) was the only company with a negative average, reflecting net reserve reductions over the period. The dynamic evolution characteristics reveal:

BP and ExxonMobil exhibited significant volatility, with BP rebounding from a historic low of -9.73 in 2022 to above 0.40, while ExxonMobil achieved a V-shaped recovery from -4.11 (2020) to 3.39 (2021); PetroChina, Chevron, TotalEnergies, and Shell showed narrow fluctuations, with PetroChina maintaining a stable range of 0.80–1.10, while Chevron de-

clined from a peak of 1.12 to below unity; Eni and Equinor demonstrated steady upward trends, improving from 0.43 to 1.13 and from −0.05 to 1.51, respectively.

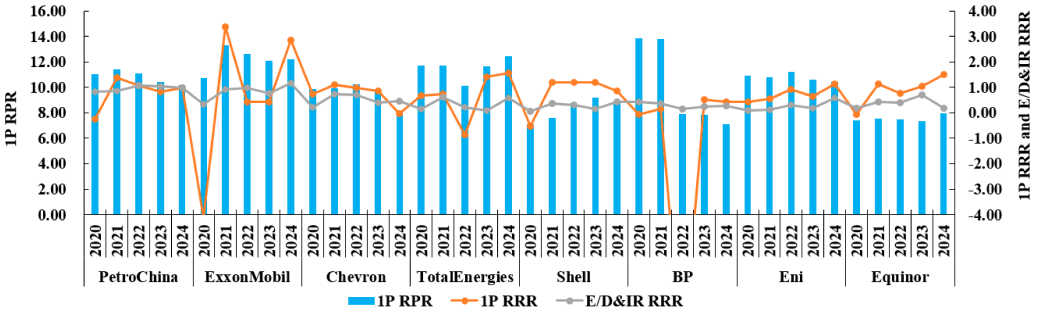


Figure 4. Correlation graph of 1P RPR, 1P RRR and E/D&IR RRR of eight oil companies (2020–2024). Data source: company annual reports, compiled by the authors.

Because the numerator of the full-scope RRR includes purchases, sales, and revisions, a high replacement ratio may reflect acquisitions or revisions rather than organic replacement capability. To distinguish organic replacement from transaction-driven changes, this paper introduces the Extensions, Discoveries and Improved Recovery Reserves Replacement Ratio (E/D&IR RRR), whose numerator includes only extensions and discoveries and improved recovery, excluding revisions, purchases, and sales. The limitation of this indicator is that it excludes positive revisions, which may contain genuine reserve additions from technical re-estimation; however, since technical revisions cannot be reliably separated from price/cost-driven revisions, this paper adopts the conservative treatment of excluding all revisions. Over the five-year period, after excluding transaction and revision effects, the E/D&IR RRR of all companies remained generally low: PetroChina (0.95) and ExxonMobil (0.83) maintained relatively high levels through exploration breakthroughs and technological innovation, while other companies all fell below 0.50, with BP (0.30) and Eni (0.26) being particularly notable. This pattern reveals an industry-wide challenge in endogenous growth: against the backdrop of conventional petroleum resource degradation, exploration and development activities alone prove insufficient to maintain reserve replacement, rendering asset transactions a pivotal variable. While maintaining a relatively high technical Reserve Replacement Ratio, PetroChina has demonstrated prudent asset transaction strategies, forming a unique development pathway.

2.2. Equity Production Scale and Composition

Equity production refers to operational production multiplied by the ownership stake or investment recovery ratio. Among the eight benchmarked oil companies, PetroChina leads the peer group in equity production, with its equity production of oil and gas equivalent showing consistent growth over the past five years. Notably, domestic production contributes up to 70% of its total output, highlighting a heavy reliance on local resources. This characteristic stands in sharp contrast to the globally balanced production distribution observed among IOCs [19].

2.2.1. Equity Production Scale Analysis

As shown in Table 2, the equity production of the eight oil companies exhibits significant variations in both scale and trends from 2020 to 2024.

In terms of production scale, PetroChina leads with an average annual equity production of 2194 MMboe, followed by ExxonMobil (1632 MMboe), Chevron (1347 MMboe), Shell (1190 MMboe), BP (1040 MMboe), TotalEnergies (954 MMboe), Equinor (747 MMboe), and Eni (640 MMboe).

Table 2. Scale and structure of equity production for eight oil companies (2020–2024, Unit: MMboe).

Company	Production Type	2020	%	2021	%	2022	%	2023	%	2024	%	Average %
PetroChina	Overseas	664	32	654	31	702	32	723	32	686	30	31
	Natural Gas	778	38	823	39	873	39	920	40	981	43	40
	Offshore	54	3	51	2	60	3	75	3	77	3	3
	Unconvention	435	21	465	22	497	22	532	23	555	24	23
	Total	2063	100	2100	100	2211	100	2290	100	2305	100	
ExxonMobil	Overseas	1137	70	1122	70	1100	69	1074	69	1070	60	68
	Natural Gas	624	39	619	38	574	36	543	35	584	33	36
	Offshore	823	51	800	50	776	49	776	50	812	46	49
	Unconvention	497	31	523	32	521	33	522	34	744	42	34
	Total	1617	100	1612	100	1591	100	1558	100	1780	100	
Chevron	Overseas	859	65	863	63	795	61	763	57	747	53	60
	Natural Gas	519	39	567	41	547	42	548	41	572	40	41
	Offshore	518	39	527	38	486	38	454	34	436	31	36
	Unconvention	444	34	484	35	475	37	546	41	673	47	39
	Total	1320	100	1372	100	1296	100	1329	100	1420	100	
Shell	Overseas	1285	97	1212	97	1114	97	1081	97	1077	97	97
	Natural Gas	602	45	550	44	509	44	492	44	512	46	45
	Offshore	754	57	729	58	726	63	714	64	711	64	61
	Unconvention	261	20	229	18	146	13	136	12	134	12	15
	Total	1326	100	1246	100	1150	100	1117	100	1109	100	
BP	Overseas	1037	95	990	96	995	95	972	96	975	96	96
	Natural Gas	427	39	411	40	434	42	435	43	439	43	41
	Offshore	542	50	548	53	537	52	507	50	506	50	51
	Unconvention	215	20	176	17	194	19	216	21	241	24	20
	Total	1088	100	1036	100	1043	100	1017	100	1014	100	
TotalEnergies	Overseas	980	100	965	100	947	100	958	100	918	100	100
	Natural Gas	389	40	380	39	348	37	329	34	334	36	37
	Offshore	637	65	607	63	575	61	595	62	583	63	63
	Unconvention	104	11	98	10	100	11	97	10	70	8	10
	Total	980	100	965	100	947	100	958	100	918	100	
Equinor	Overseas	263	35	246	33	229	31	252	33	242	32	33
	Natural Gas	337	45	354	47	367	50	349	46	356	47	47
	Offshore	631	84	635	85	637	87	653	87	655	87	86
	Unconvention	100	13	92	12	87	12	105	14	103	14	13
	Total	748	100	749	100	733	100	753	100	752	100	
Eni	Overseas	614	94	644	96	610	96	609	96	583	96	96
	Natural Gas	280	43	307	46	298	47	307	49	300	50	47
	Offshore	386	59	407	61	383	60	364	58	341	56	59
	Unconvention	11	2	10	2	11	2	9	1	8	1	2
	Total	651	100	673	100	638	100	632	100	605	100	

Data source: Rystad Energy.

Regarding production trends, the companies display distinct trajectories: PetroChina demonstrates steady growth, increasing from 2063 to 2305 MMboe; Equinor maintains stable output; ExxonMobil and Chevron exhibit minor fluctuations before recovery; TotalEnergies shows a slight decline; BP, Shell, and Eni experience sustained decreases.

This divergence in production scale and trends reflects not only the strategic positioning differences among oil companies but also the broader transformation of the global energy market landscape.

2.2.2. Equity Production Composition Analysis

Analysis of the equity production structure from 2020 to 2024 (Table 2, Figure A2) reveals diversified asset allocation characteristics among IOCs.

From a regional distribution perspective of equity production, European IOCs including TotalEnergies, Shell, BP, and Eni exhibit highly internationalized operations, with overseas production accounting for 96–100% of total output. North American counterparts ExxonMobil and Chevron maintain a balanced international-local distribution, with overseas shares of 68% and 60% respectively. In contrast, PetroChina and Equinor display strong localization tendencies, with overseas production constituting only 31% and 33% respectively.

Regarding oil and gas composition of equity production, the oil companies collectively demonstrate a transition trend toward low-carbon operations. The average annual proportion of natural gas in equity production is highest for Equinor and Eni (47%), followed sequentially by Shell (45%), Chevron (41%), BP (41%), PetroChina (40%), TotalEnergies (37%), and ExxonMobil (36%). Notably, three distinct patterns emerge: a) PetroChina, BP and Eni exhibit consistent growth in natural gas share; b) Chevron, Shell and Equinor maintain relatively stable ratios; while c) ExxonMobil and TotalEnergies show persistent declining trends in gas proportion.

In terms of onshore-offshore composition of equity production, Equinor leads in offshore development with 86% of its equity production derived from offshore fields, demonstrating its characteristic marine operational focus. This presents a striking contrast to PetroChina's predominantly onshore profile (97% onshore production). Notably, both Equinor and Shell exhibit steadily increasing offshore shares (annual growth rates of 1.2% and 0.9%, respectively, during 2020–2024), reflecting their strategic expansion into offshore hydrocarbon resources and technical expertise in marine operations [20]. Conversely, Chevron shows an accelerated decline in offshore production share (average annual decrease of 2.1% over the same period).

An analysis of conventional versus unconventional production shares reveals distinct regional patterns among these companies. North American IOCs demonstrate particular prominence, with Chevron leading industry peers at 47% unconventional production share in 2024, closely followed by ExxonMobil (42%), both showing consistent growth trends. In contrast, European IOCs maintain conservative positions: Shell (12%), TotalEnergies (8%), and Eni (1%). Meanwhile, PetroChina (21% → 24%) and BP (20% → 24%) exhibit moderate increases. These structural variations reflect both distinct geological endowments across operating regions and fundamentally different strategic approaches to unconventional resource development among these corporations.

3. Comparative Analysis of Upstream Asset Performance: PetroChina Versus IOCs

The cost and benefit indicators in this section come from the S&P Energy Portal, which compiles and standardizes data disclosed in company annual reports filed under SEC rules. These data follow the same listed-asset perimeter as the reserve data in Section 2.1, although the standardized indicators remain subject to S&P's processing conventions.

3.1. Upstream Costs Analysis

Cost control is a critical indicator for assessing the benefits derived from upstream assets. This article conducts a benchmarking analysis of the differences in the main upstream costs of eight oil companies from three aspects: exploration cost per barrel, development cost per barrel, and lifting cost per barrel. Among them, exploration and development costs represent expenditures (commonly referred to as capital expenditures or capex) incurred

in finding and developing reserves, while lifting costs pertain to the spending associated with producing those reserves [21]. Different oil companies have significant variations in the proportions of the three main types of costs [22]. Exploration costs typically account for 3% to 10%, development costs make up about 30% to 60%, and lifting costs constitute approximately 40% to 70%.

It should be noted that the three per-boe cost indicators used in this section are intensity and cost-structure measures rather than direct measures of operational efficiency. Exploration and development costs per boe divide investment expenditure by current production, and therefore capture investment intensity without accounting for the reserves added or the timing of investment. Lifting costs per boe are closer to a recurring operating cost, but their broad definition—including taxes, transport, and production-related G&A—also limits cross-company comparability. Accordingly, the cost gaps reported below should be interpreted as differences in cost structure and investment intensity, and not as evidence of operational efficiency alone.

3.1.1. Exploration Costs per Boe of Production

Exploration costs refer to the costs incurred in identifying areas that may warrant examination in the search for hydrocarbons, including geological and geophysical/seismic costs as well as exploration drilling costs (usually including appraisal drilling costs). Exploration costs per boe of Production: Exploration Costs Incurred/Total Oil and Gas Production.

Analysis of exploration cost data from 2020 to 2024 reveals that the average exploration cost across eight major oil companies stood at 1.65 USD/boe (Table A4). Notably, U.S. IOCs Chevron and ExxonMobil demonstrated the lowest exploration costs at 0.79 and 0.80 USD/boe, respectively. European IOCs—TotalEnergies, BP, Eni, Equinor, and Shell-followed with costs ranging from 1.16 USD/boe to 2.10 USD/boe. In contrast, PetroChina's average exploration cost reached 3.50 USD/boe, significantly exceeding international peers.

Regarding exploration cost as a percentage of three major cost categories (2020–2024), the industry average was 6%. ExxonMobil, Chevron and TotalEnergies maintained the lowest ratios (3–4%), while BP, Eni, Shell, and Equinor occupied the mid-range (6–8%). PetroChina's exploration cost ratio averaged 10%, substantially higher than international counterparts.

PetroChina's exploration costs and cost ratio are both higher than those of the other companies. This may partly reflect the increasing geological complexity of mature domestic basins and higher management and maintenance expenditures, although the gap should not be attributed to operational efficiency alone.

3.1.2. Development Costs per Boe of Production

Development costs refer to the costs incurred to develop reserves that are undeveloped and/or non-producing, usually also including capital spent to maintain/expand productivity of reserves already developed; they may include amounts attributable to related gas gathering systems, etc. Development costs per boe of production: Development Costs Incurred/Total Oil and Gas Production.

Analysis of 2020–2024 development cost data reveals a consistent upward trend, with industry averages rising from 9.59 to 13.90 USD/boe, where TotalEnergies maintained the lowest five-year average development costs at 8.71 USD/boe, followed by ExxonMobil, Chevron, BP, and Equinor (10.32–11.25 USD/boe), while Shell, PetroChina, and Eni recorded above-average costs ranging from 11.52 to 14.43 USD/boe.

The analysis of development costs as a percentage of three major cost categories from 2020 to 2024 shows an average of 43% across the eight oil companies, with TotalEnergies (32%) and ExxonMobil (37%) demonstrating optimal cost control, PetroChina and Shell

occupying the intermediate range (37–42%), while BP, Chevron, Equinor, and Eni significantly exceeded the average (46–54%), reflecting substantial disparities in capital allocation efficiency among these oil companies.

3.1.3. Lifting Costs per Boe of Production

Lifting costs refer to the cost of extracting oil and gas from the reservoir and other related costs; they include production expenses, taxes other than income taxes, shipping/transportation/handling expenses, and production-related general and administrative expenses. Lifting costs per boe of production: (Production Expenses + Shipping/Transportation/Handling Expenses + Taxes Other Than Income + Production-Related General and Administrative)/Total Oil and Gas Production.

Analysis of lifting costs across eight major oil companies from 2020 to 2024 demonstrates a marked positive association with international crude prices (Figure 5), with an industry mean of 13.46 USD/boe, where Equinor achieved the most competitive lifting costs at 9.10 USD/boe, followed by Eni, Chevron, and BP (10.31–11.59 USD/boe), while Shell, ExxonMobil, TotalEnergies, and PetroChina recorded above-average costs ranging from 13.65 to 17.89 USD/boe.

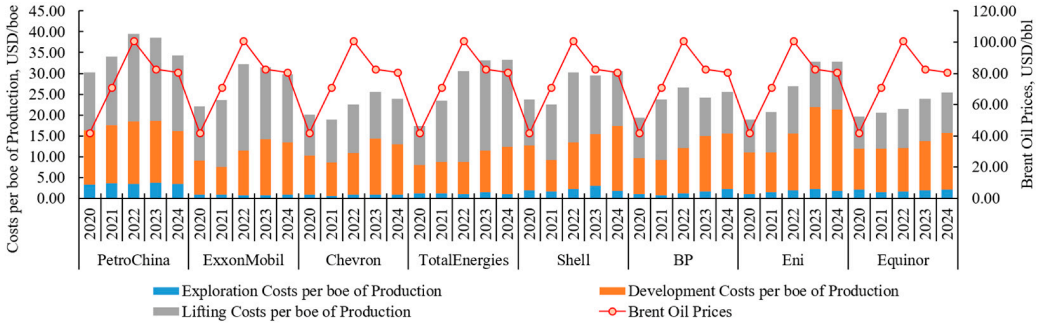


Figure 5. Relationship between unit Exploration, Development and Lifting Costs and Brent Crude Oil Benchmark Prices trends among eight petroleum companies (2020–2024). Data source: S&P Energy Portal.

An examination of lifting costs as a percentage of three major cost components (2020–2024) reveals an industry average of 50% among the eight oil companies, with Eni demonstrating the most efficient cost structure (40%), followed by Equinor, BP, Chevron, Shell, and PetroChina (41–50%), while ExxonMobil and TotalEnergies exhibited above-average ratios (60–63%), revealing significant variations in lifting cost management strategies.

An integrated cost analysis of exploration, development, and lifting expenditures (2020–2024) demonstrates that PetroChina's aggregate cost is the highest in the sample, ranging from 30 USD/boe to 40 USD/boe (5-year mean: 35.31 USD/boe), compared with the seven IOCs' consolidated costs of 20–30 USD/boe. Notably, Equinor (22.15 USD/boe) and Chevron (22.18 USD/boe) achieved relatively optimal integrated costs, followed by BP (23.85 USD/boe), Eni (26.43 USD/boe), Shell (27.26 USD/boe), TotalEnergies (27.55 USD/boe), and ExxonMobil (27.77 USD/boe). This comparison indicates that PetroChina has a notable gap in overall cost structure relative to IOCs, although the magnitude of the gap is partly affected by geological endowment and investment timing.

3.2. Upstream Benefit Analysis

This paper selects three key economic indicators—Free Cash Flow after Finding and Development Costs per boe, Pre-tax profit per boe, and Recycle Ratio—to holistically evalu-

ate both the economic viability and cash flow sustainability of upstream operations in oil companies (Table A5).

3.2.1. Free Cash Flow After Finding and Development Costs per Boe

Free Cash Flow after Finding and Development Costs per boe (FCF after F&D Costs per boe) serves as a critical metric for evaluating the financial sustainability and value-creation potential of upstream oil and gas operations. By deducting capital expenditures related to exploration and development from operating cash flows, this indicator reveals the true cash-generating capacity of a company's producing assets after accounting for the costs required to maintain or grow its reserve base. It is calculated as: [Cash Flow (Results of Oil and Gas Operations) − Finding and Development (F&D) Costs Incurred]/Total Oil and Gas Production. A consistently positive Free Cash Flow after Finding and Development Costs per boe demonstrates operational efficiency, prudent capital allocation, and the ability to generate surplus cash for debt reduction, shareholder returns, or opportunistic investments. Conversely, negative values may signal overinvestment in high-cost reserves or structural profitability challenges, particularly in volatile commodity price environments. As such, this metric provides essential insights into both short-term financial resilience and long-term strategic positioning within the capital-intensive upstream sector.

Through an in-depth analysis of the Free Cash Flow after Finding and Development Costs per boe of eight major oil companies from 2020 to 2024, this study reveals a pronounced cyclical fluctuation pattern (Figure 6). The industry average surged from $2.80/boe in 2020 to a peak of $24.50/boe in 2022 before gradually declining. Among these oil companies, Chevron delivered the most robust five-year average performance at $17.97/boe, achieving a record high of $32.38/boe in 2022. Equinor and Shell followed closely with respective averages of $15.78/boe and $13.42/boe, demonstrating strong cash flow generation capabilities. Notably, ExxonMobil registered an outlier value of –$14.09/boe in 2024, potentially reflecting substantial capital expenditures or strategic realignment. Although industry metrics retreated from their 2022 peak, they stabilized above $8/boe, indicating that IOCs have established more resilient cash flow management systems through portfolio optimization and enhanced capital discipline in the post-pandemic era. This evolution has laid a solid financial foundation for addressing energy transition challenges. The observed trajectory vividly illustrates the strategic adaptability and developmental resilience of the global oil and gas industry in volatile market conditions.

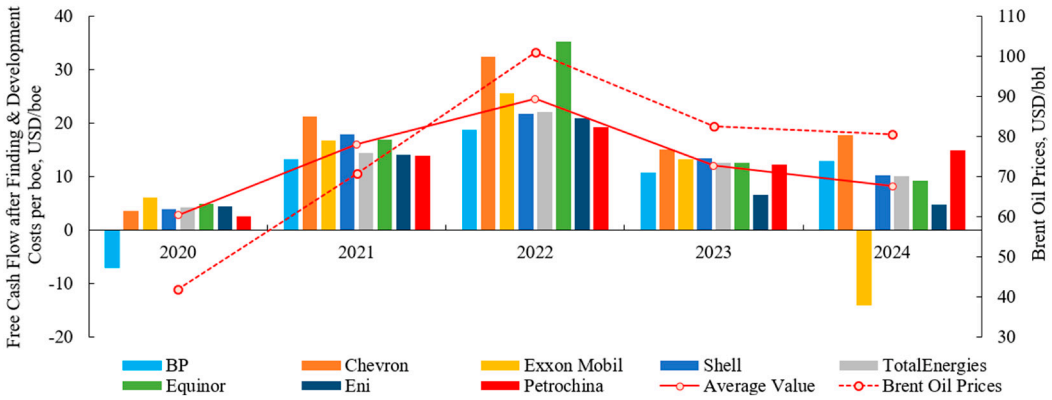


Figure 6. Dynamic relationship between Free Cash Flow after Finding and Development Costs per boe and Brent Crude Oil Benchmark Prices among eight petroleum companies (2020–2024). Data source: S&P Energy Portal.

3.2.2. Pre-Tax Profit per Boe

Pre-tax Profit per boe refers to the profit generated by each barrel of oil equivalent before deducting all finding and development costs and taxes. This indicator is crucial for oil companies as it directly reflects their profitability and operational efficiency. This metric is calculated through a comprehensive aggregation of financial components: Pre-tax Profit per boe = (Oil and Gas Revenues + Other Revenue − Production Expense − Shipping/Transportation/Handling Expenses − Taxes Other than Income − Production-Related General and Administrative − Exploration Expenses − Depreciation, Depletion and Amortization − Dismantle, Abandonment and Restoration Costs − Accretion of Discount − Other Expenses)/Total Oil and Gas Production. The metric's analytical value stems from its ability to isolate operational performance from financial structuring effects, providing critical insights into cost management efficiency and revenue generation capacity at the asset level.

Pre-tax profit per boe is affected by fiscal regimes, commodity mix, and realized prices, so cross-company differences should not be read as operational efficiency alone. Year-to-year variation within a company also reflects oil price cycles.

As evident from the data in Figure 7, oil prices demonstrate a marked positive correlation with pre-tax profit per barrel among oil companies. During the 2020 oil price trough, seven of the eight surveyed companies reported losses, with a mean pre-tax profit of –7.05 USD/boe. Notably, PetroChina maintained positive profitability at 4.71 USD/boe as the sole exception. In contrast, the 2022 oil price surge propelled the industry average to a five-year peak of 45.82 USD/boe. Analysis of the five-year average pre-tax profit/boe reveals Equinor's exceptional performance at 48.27 USD/boe, substantially outperforming peers. The subsequent ranking shows Chevron (22.42 USD/boe), Eni (20.89 USD/boe), TotalEnergies (19.91 USD/boe), ExxonMobil (17.70 USD/boe), Shell (17.69 USD/boe), PetroChina (16.39 USD/boe), and BP (14.41 USD/boe).

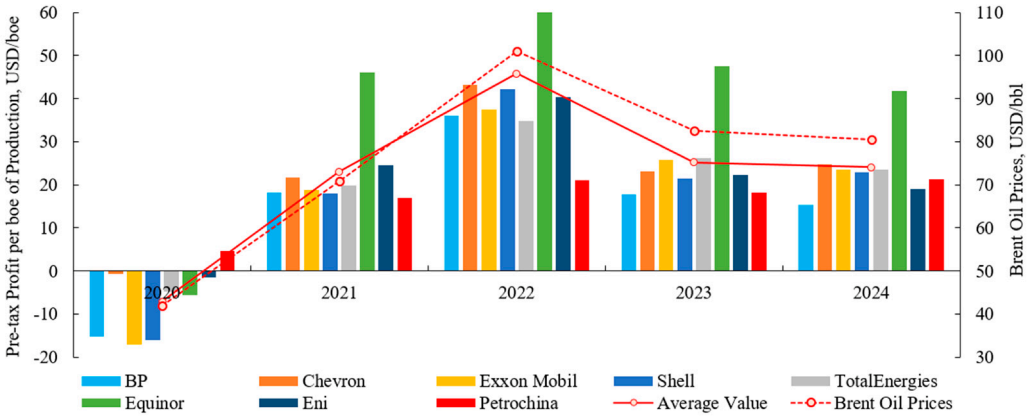


Figure 7. Dynamic Relationship Between Pre-Tax Profit per boe and Brent Crude Oil Benchmark Prices among eight petroleum companies (2020–2024). Note: the figure shows a descriptive association; no statistical significance test was performed. Data source: S&P Energy Portal.

Equinor's superior profitability stems from its low-cost operations and policy advantages. Particularly during the 2022 Russia–Ukraine conflict, the company capitalized on arbitrage opportunities through flexible pricing mechanisms in European spot gas markets, further enhanced by long-term contract price locks, driving its pre-tax profit/boe to record highs.

PetroChina demonstrates remarkable counter-cyclical resilience. While the broader industry suffered losses during the 2020 price collapse, the company achieved positive returns through integrated value chain synergies, stringent cost controls, and domestic

"price floor" policy support. However, its relatively subdued performance during high-price periods (significantly below industry average) reveals limited pro-cyclical profit elasticity alongside strengthened counter-cyclical financial robustness.

3.2.3. Recycle Ratio

Recycle Ratio, calculated as Net-back per boe divided by one-year Reserve Replacement Cost per boe, serves as a critical performance metric in upstream petroleum operations. It measures the economic efficiency of reserve replacement by comparing the net profit generated from current production (Net-back) with the capital expenditure required to add new reserves: a ratio above 1 indicates that the company is profitably replacing its reserves, whereas a ratio below 1 suggests potential economic challenges in reserve replacement. Net-back per boe is calculated as (Oil and Gas Revenue − Lifting Costs)/Total Oil and Gas Production. The underlying Netback per boe and Reserve Replacement Cost per boe are not separately disclosed in the standardized S&P Energy Portal dataset used here. The Recycle Ratio is therefore reported as a derived indicator, and its interpretation should remain cautious.

A systematic analysis of the Recycle Ratio across the eight oil companies from 2020 to 2024 reveals a distinct V-shaped recovery pattern (Figure 8), with the industry mean improving from −0.26 in 2020 to 2.65 in 2024, broadly tracking Brent crude price movements (41.96 → 80.52 USD/bbl).

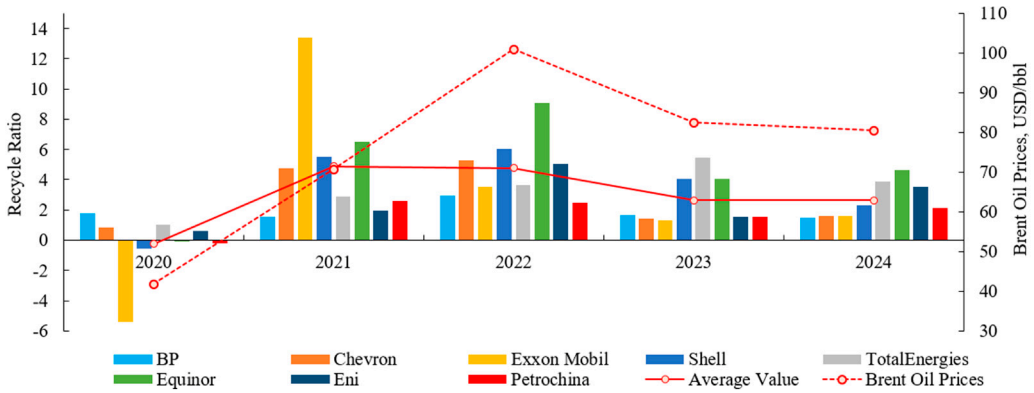


Figure 8. Dynamic relationship between Recycle Ratio and Brent Crude Oil Benchmark Prices among eight petroleum companies (2020–2024). Note: the figure shows a descriptive association; no statistical significance test was performed. Data source: S&P Energy Portal.

Equinor demonstrated the most outstanding performance with a five-year average Recycle Ratio of 4.84, peaking at 9.07 in 2022. Shell and TotalEnergies exhibited relatively stable performance with smaller fluctuations. PetroChina, as the sole NOC in the sample, recorded a five-year average of 1.70, slightly below international peers. Notably, ExxonMobil achieved a peak ratio of 13.41 in 2021, primarily reflecting elevated netback driven by the post-pandemic price recovery and a temporarily low Reserve Replacement Cost associated with the timing of the Guyana FID and reserve bookings, rather than a sustained improvement in capital efficiency. Given that the annual Recycle Ratio is dominated by the oil price cycle, the five-year average is more suitable for structural comparison; even on this basis, the gap between Equinor and PetroChina may partly reflect natural gas price exposure and portfolio differences rather than structural efficiency alone.

The year 2022 marked a critical inflection point, with the industry average reaching its five-year peak. Although ratios moderated thereafter, they remained consistently above 1.5, indicating that IOCs have established efficient asset portfolios and cost control systems adapted to the new normal of 80 USD/bbl oil prices, thereby sustaining reserve replacement.

This evolutionary trajectory reflects the strategic transformation and value reconfiguration of the global oil and gas industry in the post-pandemic era.

4. Benchmarking Analysis of Strategy for Upstream Asset Management: PetroChina Versus IOCs

Building upon the preceding quantitative analysis, this section extends the benchmarking framework to the strategic dimension of upstream asset management [23,24]. We examine three interrelated strategic domains—portfolio deployment, operational value realization, and low-carbon transition—to identify the strategic drivers behind PetroChina's performance relative to IOCs.

The following strategic benchmarking incorporates recent industry developments through 2025, including major M&A transactions, portfolio adjustments, and transition investment revisions. These events postdate the quantitative analysis period (2020–2024) but are presented to illustrate emerging strategic trajectories and to ground our recommendations in the most current industry context. All 2025 data cited herein are derived from publicly available corporate disclosures and third-party industry reports.

4.1. Asset Portfolio Optimization and Deployment Strategies

IOCs exhibit a marked trend toward regional concentration in asset allocation, prioritizing economies of scale in core production areas through large-scale M&A. ExxonMobil's USD 60 billion acquisition of Pioneer Natural Resources (completed 2024) [25] and Chevron's USD 53 billion acquisition of Hess (announced 2023, completed 2025) [26] exemplify this strategy, consolidating Permian Basin dominance and securing high-quality deepwater assets in Guyana. These transactions reflect a broader IOC strategy of deploying capital to high-margin, low-breakeven basins while divesting non-core or high-cost assets. The result is a highly concentrated, operationally efficient portfolio with shorter development cycles from acquisition to production.

PetroChina's asset portfolio follows a distinctive "dual-track" configuration: domestic operations focus on conventional onshore oil and gas (over 70% of production), while overseas assets are strategically concentrated along Belt and Road Initiative routes. Unlike the aggressive M&A approach of IOCs, PetroChina adopts a gradual equity acquisition model, as exemplified by the West Qurna-1 project in Iraq—where phased investments spanning over a decade culminated in its assumption of lead operator status in 2024. This approach prioritizes strategic regional clustering and value enhancement through project extensions and technology transfer, albeit with longer development cycles (7–9 years versus 3–5 years for IOCs).

IOCs use high-frequency, large-scale transactions to reshape portfolios in response to market signals, whereas PetroChina relies on a more measured, relationship-based expansion model. While the latter provides stability and access to resource-rich host countries, it also constrains the company's ability to swiftly reallocate capital toward emerging low-carbon or high-return opportunities—a flexibility gap that may become increasingly consequential as the energy transition accelerates.

4.2. Asset Operations and Value Optimization Strategies

Complementing portfolio deployment, operational efficiency determines how effectively a company converts its asset base into financial returns. IOCs have established relatively high operational efficiency through systematic cost control and digital integration. ExxonMobil's integration of Pioneer Natural Resources is projected to deliver over USD 3 billion in annual structural cost reductions through organizational optimization. This excellence rests on three pillars: (1) multidimensional optimization of cost structure, carbon

intensity, and cash-flow recovery speed; (2) continuous portfolio quality improvement through high-frequency adjustments; and (3) full-chain digital synergy, with upstream returns reported to exceed the industry average.

PetroChina is systematically narrowing this gap through its "Enhanced Quality and Value Creation" strategy. Key innovations include a global treasury management system that has substantially improved capital turnover efficiency, pioneering data asset capitalization for Chinese state-owned enterprises, and project-specific refined management applying mature domestic technologies across overseas operations. In 2024, PetroChina's overseas business achieved record equity production and exceeded annual targets.

The critical differentiator lies not in isolated initiatives but in systemic integration. IOCs embed operational excellence into corporate culture, governance, and incentive structures, creating self-reinforcing efficiency gains across price cycles. PetroChina has demonstrated strong catch-up momentum in discrete technological and financial innovations, yet lags in institutionalizing efficiency as a strategic imperative independent of oil price tailwinds. Bridging this "institutional efficiency gap" represents the next frontier for PetroChina's operational upgrading.

4.3. Low-Carbon Transition and Technological Innovation Strategies

The low-carbon transition landscape has undergone significant recalibration since 2024, with IOCs pivoting from expansive decarbonization pledges to more pragmatic, return-focused capital allocation. European IOCs have substantially scaled back transition ambitions: BP revised its 2030 low-carbon investment target to USD 1.5–2.0 billion annually (a USD 5 billion reduction) [27], while Shell limited its low-carbon capital employed to below 10% of total capital [28]. Equinor nearly halved its 2025–2027 renewables investment to approximately USD 5 billion [29]. American IOCs pursue a technology-driven path: ExxonMobil committed up to USD 20 billion toward low-emission opportunities, focusing on CCS, low-carbon hydrogen, and lithium extraction, while Chevron leverages portfolio optimization to reduce upstream carbon intensity.

PetroChina implements a "dual-engine" decarbonization strategy: accelerating natural gas development (raising overseas gas production to approximately 40% of total output) while exporting Chinese CCUS and digital oilfield technologies to Iraq and Chad projects. Its innovations include establishing a BRI green energy cooperation framework, promoting Chinese technical standards abroad, and pioneering integrated renewable–conventional energy development. CNPC reported record overseas equity production in 2025, maintaining this level for six consecutive years.

The strategic divergence between PetroChina and IOCs in the low-carbon transition is substantial. IOCs operate in a volatile policy and market environment, oscillating between decarbonization commitments and short-term profitability pressures; the resulting strategic reversals create uncertainty for long-term investors. PetroChina, by contrast, pursues a more consistent "gas as bridge" trajectory aligned with China's domestic energy security priorities and its gradual decarbonization timeline. The key question for PetroChina is whether this "follower" strategy—using natural gas as a bridge fuel and CCUS technology export as a differentiated lever rather than pursuing frontier low-carbon investment on the same scale as European IOCs—can accelerate sufficiently to maintain competitiveness in a world increasingly demanding credible climate action from national oil companies. The associated risk is that, if global climate policy tightens faster than expected, the window for natural gas as a bridge fuel may be shorter than anticipated, in which case PetroChina would need to accelerate CCUS commercialization to catch up.

5. Integrated Gap Identification and Discussion

5.1. Integrated Gap Identification

The last step in a benchmarking exercise is to bring the separate dimensions together and show where the target company actually stands. Figure 9 does this for PetroChina against the average of the seven IOCs on eight dimensions: 1P reserve scale, RPR, RRR, natural gas reserve share, overseas reserve share, integrated upstream cost, pre-tax profit per boe, and Recycle Ratio. All dimensions are calculated as five-year averages (2020–2024) for both PetroChina and the IOC group, so that year-to-year price and investment cycles do not dominate the comparison. The IOC average is the reference line, and PetroChina's values are plotted as indices against it.

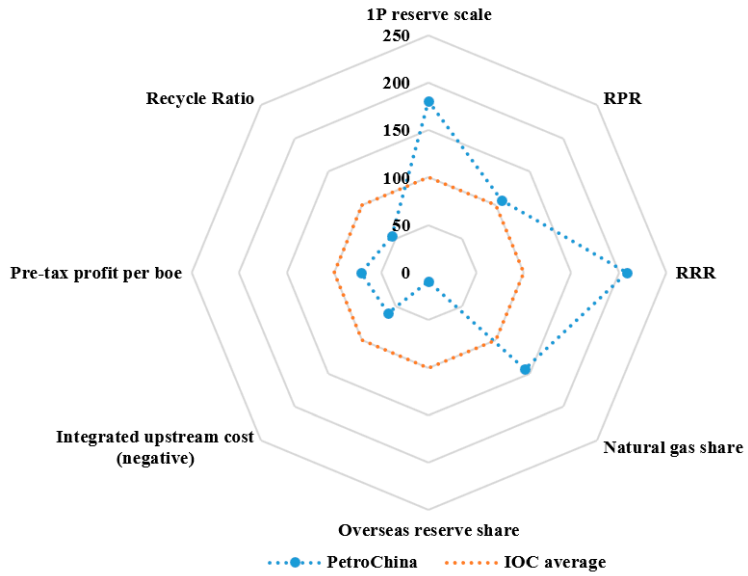


Figure 9. Radar Chart of PetroChina's Integrated Benchmarking Gaps Relative to the IOC Average (2020–2024). Note: All dimensions are calculated as five-year averages (2020–2024) for both PetroChina and the seven IOCs, based on company annual reports. Each dimension is normalized to 100 for the IOC average (seven IOCs, excluding PetroChina), so values above 100 indicate an advantage. Integrated upstream cost is a negative-direction indicator and is therefore plotted inside the baseline (60.53 = 100 − 39.47): the further inward the point, the larger the disadvantage. The RRR dimension uses the full-scope ratio; BP's five-year average of −1.74 pulls the IOC mean down to 0.384, which inflates PetroChina's index to 208.17. Excluding BP, the deviation is about +8.4% (index ≈ 108). Data source: calculated by the authors from Tables A1–A4 and Section 3.

What the figure shows is uneven rather than uniformly strong or weak. On the five-year average, PetroChina's reserve base is far larger than the IOC average (index ≈ 180), and natural gas accounts for a much higher share of its reserves (≈143); its RPR (≈108) and RRR (≈208, or ≈108 once BP is excluded) are close to or above the reference line. The weak side is equally clear. Integrated upstream cost sits at about 61 on the reversed scale, pre-tax profit per boe at about 71, and the Recycle Ratio at about 55. The sharpest gap is overseas reserve share, at roughly 9, which places PetroChina near the center of the chart on that axis. Size and resource structure are strengths; cost, profitability and international exposure are not.

5.2. Discussion

Reading the pattern. The eight dimensions point in two directions. PetroChina's reserve scale, gas share, RPR and RRR are at or above the IOC average, while its cost, pre-tax profit per boe, Recycle Ratio and overseas reserve share are below it. The first group reflects

the size and composition of the resource base; the second reflects how that base is converted into cash and how far it extends beyond the home country. The two groups should not be read as offsetting each other, because they answer different questions: whether the company has resources, and whether it earns enough from them.

What can realistically be done. Overseas acquisition is constrained by geopolitics: the Belt and Road portfolio is concentrated, and sanctions exposure limits where PetroChina can go. Institutionalizing efficiency is constrained by the path dependence of SOE governance. Cost control is the least constrained and the quickest to show results, which is why it should come first; overseas portfolio adjustment depends on windows that open and close, so it is better pursued opportunistically than on a fixed schedule; efficiency institutionalization is a medium-term task; and the low-carbon pathway needs steady funding and a realistic view of how long the gas window will stay open.

Limitations. Exploration and development spending is investment, and dividing it by current production measures investment intensity rather than efficiency; the finding and development cost per barrel of reserves added is not covered here. The lifting-cost definition is broad, including taxes and transport, which weakens cross-country comparability. Eight companies over five years is a small sample, so the analysis stays descriptive. The strategic discussion is qualitative and in places rests on public information rather than systematic evidence. The Netback and Reserve Replacement Cost values underlying the Recycle Ratio are not separately available in the standardized dataset, which limits independent verification. The annual Recycle Ratio is also dominated by the oil-price cycle and by the timing of reserve bookings; the five-year average is therefore more suitable for structural comparison, and even on this basis cross-company differences may partly reflect natural gas price exposure and portfolio composition rather than structural efficiency alone.

6. Conclusions and Recommendations

This study benchmarks PetroChina against seven IOCs over 2020–2024 on upstream asset performance and strategic management, drawing on annual-report reserve data, Rystad Energy equity production data, and S&P Energy Portal financial data, and covering asset scale and structure, cost–benefit performance, and strategic orientation.

PetroChina holds a large reserve base (18,552 MMboe in 2024, second only to ExxonMobil), with a gas-dominant composition (about 67%) that provides a structural advantage in the low-carbon transition. Its reserve decline rate (about 1.68% annually) is below the sample average of about 3.75%, reflecting reserve replacement through exploration and portfolio management rather than through acquisitions. In production, PetroChina leads the peer group in absolute equity output (average approximately 2194 MMboe/year) with consistent growth. Its asset structure, however, remains heavily domestic (overseas reserves below 7%), in contrast to the highly internationalized portfolios of European IOCs (over 90% overseas); transactional reserve additions are minimal, indicating a preference for endogenous growth over active M&A.

The cost–benefit analysis points to a clear gap. PetroChina's integrated upstream cost (35.31 USD/boe) is higher than the IOC average (22–28 USD/boe), and the difference is most pronounced in exploration expenditure (3.50 USD/boe, against 0.80–2.10 USD/boe for peers). Part of this gap reflects geological endowment and investment timing; accordingly, the cost gap should be interpreted as a difference in investment intensity and cost structure rather than as a direct measure of operational efficiency. Despite the cost disadvantage, PetroChina remained profitable during the 2020 price trough (4.71 USD/boe) when most IOCs recorded losses, although its upside during high-price periods is more limited, as reflected in a lower five-year average pre-tax profit (16.39 USD/boe, against 48.27 USD/boe for Equinor) and Recycle Ratio (1.70, against 4.84); the latter should be read with caution, as

the underlying Netback and Reserve Replacement Cost values are not separately disclosed, and the ratio partly reflects gas price exposure and portfolio composition rather than structural efficiency alone. Strategically, IOCs use high-frequency M&A to reshape portfolios toward high-margin basins, with development cycles of 3–5 years, whereas PetroChina relies on gradual equity acquisition with cycles of 7–9 years. Operationally, IOCs embed efficiency into governance and culture so that gains persist across price cycles, whereas PetroChina has moved quickly on discrete technological and financial innovations but has been slower to institutionalize efficiency as a strategic priority. In the low-carbon transition, IOCs have shifted since 2024 from expansive pledges toward return-focused capital allocation, while PetroChina's gas-focused, technology-export model offers a consistent and lower-risk pathway aligned with China's energy security priorities.

Four recommendations follow from these findings. First, PetroChina should selectively increase high-quality overseas asset exposure in low-geopolitical-risk regions while maintaining domestic supply security. Second, it should invest in digital oilfield technologies and enhanced recovery methods to curb per-barrel costs, with priority given to reducing exploration and development expenditure per boe through efficiency gains rather than output cuts. Third, it should embed efficiency metrics into corporate governance and incentive structures so that operational excellence becomes institutionalized rather than dependent on price cycles. Fourth, it should continue to use natural gas as a bridge fuel while scaling up CCUS and renewable–conventional integration pilots, reinforcing its license to operate in a carbon-constrained world. These four are not alternatives to be chosen between: overseas asset exposure and per-barrel cost control both work on the cost side, but neither will hold unless efficiency is built into governance and incentives, while the gas-plus-CCUS pathway is a longer-term condition for keeping upstream assets viable under carbon constraints. In practice, cost control is the entry point, overseas portfolio adjustment and efficiency institutionalization carry the middle period, and the low-carbon pathway determines whether the gains survive the transition.

By integrating asset-scale, cost–benefit, and strategic analyses within a single benchmarking framework, this study offers a more comprehensive diagnostic of competitive positioning than single-dimensional evaluations. Although the empirical focus is PetroChina, the framework and findings are not limited to Chinese national oil companies: the three-tier structure can be applied to other state-owned and international oil companies seeking to benchmark asset portfolios, cost structures, and transition pathways, and the comparison of NOC and IOC models offers a reference point for firms weighing domestic supply obligations against international portfolio expansion.

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Appendix A

Table A1. Statistical table of 1P reserves, growth volume, and growth rate of eight oil companies (2020–2024).

Company	Type	2020	2021	2022	2023	2024	2020–2024 Average
PetroChina	1P Reserves, MMboe	18,202	18,843	18,926	18,604	18,552	18,625
	1P Reserves Growth Volume, MMboe	−2110	642	82	−322	−51	−352
	1P Reserves Growth Rate, %	−10.39	3.53	0.44	−1.70	−0.28	−1.68
ExxonMobil	1P Reserves, MMboe	15,211	18,536	17,742	16,928	19,949	17,673
	1P Reserves Growth Volume, MMboe	−7234	3325	−794	−814	3021	−499
	1P Reserves Growth Rate, %	−32.23	21.86	−4.28	−4.59	17.85	−0.28
TotalEnergies	1P Reserves, MMboe	12,328	12,062	10,190	10,564	11,073	11,243
	1P Reserves Growth Volume, MMboe	−353	−266	−1871	374	509	−321
	1P Reserves Growth Rate, %	−2.78	−2.16	−15.52	3.67	4.82	−2.39
Chevron	1P Reserves, MMboe	11,134	11,264	11,229	11,069	9804	10,900
	1P Reserves Growth Volume, MMboe	−297	130	−35	−160	−1265	−325
	1P Reserves Growth Rate, %	−2.59	1.17	−0.31	−1.42	−11.43	−2.92
Shell	1P Reserves, MMboe	9123	9365	9578	9787	9620	9495
	1P Reserves Growth Volume, MMboe	−1971	241	214	209	−167	−295
	1P Reserves Growth Rate, %	−17.77	2.65	2.27	2.18	−1.71	−2.48
BP	1P Reserves, MMboe	17,982	16,954	7183	6759	6248	11,025
	1P Reserves Growth Volume, MMboe	−1358	−1030	−9771	−423	−514	−2619
	1P Reserves Growth Rate, %	−7.02	−5.72	−57.63	−5.90	−7.56	−16.77
Eni	1P Reserves, MMboe	6905	6628	6614	6414	6497	6612
	1P Reserves Growth Volume, MMboe	−363	−278	−14	−200	83	−154
	1P Reserves Growth Rate, %	−4.99	−4.01	−0.21	−3.02	1.29	−2.19
Equinor	1P Reserves, MMboe	5260	5356	5191	5214	5571	5318
	1P Reserves Growth Volume, MMboe	−744	96	−165	24	358	−86
	1P Reserves Growth Rate, %	−12.40	1.83	−3.08	0.44	6.85	−1.27

Note: The annual reserve growth rate in Table A1 is calculated as (reserves in year t − reserves in year t − 1)/reserves in year t − 1; the 2020 rate uses 2019 year-end reserves as the base. The "Total Annual Change" in Table 1 equals the "1P Reserves Growth Volume" reported in this appendix for each company and year. The total annual change is the sum of the E&P-driven and AT-driven subtotals. For Eni in 2021, the E&P-driven subtotal (−274 MMboe) and the AT-driven subtotal (−4 MMboe) sum to the total annual change (−278 MMboe). For all companies, the Total Annual Change matches the "1P Reserves Growth Volume" in this appendix; minor residual differences with year-end reserve levels, where present, arise from rounding of the individual categories.

Table A2. Statistical table of 1P reserves composition and proportion for eight oil companies (2020–2024).

Company	Type		2020	2021	2022	2023	2024
PetroChina	Crude Oil Reserves, MMboe		5402	6273	6594	6375	6321
	Natural Gas	Reserves, MMboe	12,800	12,571	12,333	12,228	12,231
		Proportion,%	70.32	66.71	65.16	65.73	65.93
	PD Reserves, MMboe		11,848	12,686	12,688	12,325	12,098
	PUD	Reserves, MMboe	6353	6158	6238	6278	6454
		Proportion,%	34.91	32.68	32.96	33.75	34.79
	Domestic Reserves, MMboe		16,821	17,529	17,723	17,372	17,376
	Overseas	Reserves, MMboe	1381	1315	1203	1231	1176
		Proportion,%	7.59	6.98	6.36	6.62	6.34

Table A2. *Cont.*

Company	Type		2020	2021	2022	2023	2024
ExxonMobil	Natural Gas	Crude Oil Reserves, MMboe	8885	12,174	11,471	11,184	13,691
		Reserves, MMboe	6326	6362	6271	5744	6258
		Proportion,%	41.59	34.32	35.35	33.93	31.37
	PUD	PD Reserves, MMboe	10,241	12,236	11,143	10,676	12,599
		Reserves, MMboe	4970	6300	6599	6252	7350
		Proportion,%	32.67	33.99	37.19	36.93	36.84
	Overseas	Domestic Reserves, MMboe	5207	5966	5677	5297	8185
		Reserves, MMboe	10,004	12,570	12,065	11,631	11,764
		Proportion,%	65.77	67.81	68.00	68.71	58.97
Chevron	Natural Gas	Crude Oil Reserves, MMboe	6147	6113	6085	6006	5075
		Reserves, MMboe	4987	5151	5144	5063	4729
		Proportion,%	44.79	45.73	45.81	45.74	48.24
	PUD	PD Reserves, MMboe	7730	7404	7322	7613	7043
		Reserves, MMboe	3404	3860	3907	3456	2761
		Proportion,%	30.57	34.27	34.79	31.22	28.16
	Overseas	Domestic Reserves, MMboe	3051	3857	4097	4246	4025
		Reserves, MMboe	8083	7408	7133	6823	5779
		Proportion,%	72.59	65.76	63.52	61.64	58.94
TotalEnergies	Natural Gas	Crude Oil Reserves, MMboe	5804	5843	5716	5487	5980
		Reserves, MMboe	6524	6219	4474	5077	5093
		Proportion,%	52.92	51.56	43.91	48.06	45.99
	PUD	PD Reserves, MMboe	7985	7980	6990	6835	6965
		Reserves, MMboe	4343	4082	3200	3729	4108
		Proportion,%	35.23	33.84	31.40	35.30	37.10
	Overseas	Domestic Reserves, MMboe	0	0	0	0	0
		Reserves, MMboe	12,328	12,062	10,190	10,564	11,073
		Proportion,%	100.00	100.00	100.00	100.00	100.00
Shell	Natural Gas	Crude Oil Reserves, MMboe	4621	4581	4680	4661	4630
		Reserves, MMboe	4502	4784	4898	5126	4990
		Proportion,%	49.35	51.08	51.14	52.38	51.87
	PUD	PD Reserves, MMboe	7768	7541	6828	6829	6863
		Reserves, MMboe	1356	1824	2750	2958	2757
		Proportion,%	14.86	19.48	28.71	30.22	28.66
	Overseas	Domestic Reserves, MMboe	470	482	695	752	606
		Reserves, MMboe	8654	8883	8883	9035	9014
		Proportion,%	94.85	94.85	92.74	92.32	93.70
BP	Natural Gas	Crude Oil Reserves, MMboe	10,661	10,124	3997	3747	3699
		Reserves, MMboe	7321	6830	3186	3012	2549
		Proportion,%	40.71	40.29	44.35	44.56	40.80
	PUD	PD Reserves, MMboe	10,112	9740	4307	4201	3860
		Reserves, MMboe	7871	7214	2877	2558	2387
		Proportion,%	43.77	42.55	40.05	37.85	38.21
	Overseas	Domestic Reserves, MMboe	378	374	337	251	202
		Reserves, MMboe	17,604	16,580	6846	6508	6046
		Proportion,%	97.90	97.79	95.31	96.29	96.77
Eni	Natural Gas	Crude Oil Reserves, MMboe	3515	3261	3154	3105	2993
		Reserves, MMboe	3390	3367	3460	3309	3504
		Proportion,%	49.09	50.80	52.31	51.59	53.93
	PUD	PD Reserves, MMboe	4900	4608	4191	3995	3710
		Reserves, MMboe	2005	2020	2423	2419	2787
		Proportion,%	29.04	30.48	36.63	37.71	42.90

Table A2. *Cont.*

Company	Type		2020	2021	2022	2023	2024
Eni	Overseas	Domestic Reserves, MMboe	243	369	353	377	368
		Reserves, MMboe	6662	6259	6261	6037	6129
		Proportion,%	96.48	94.43	94.66	94.12	94.34
Equinor	Natural Gas	Crude Oil Reserves, MMboe	2510	2616	2528	2635	2557
		Reserves, MMboe	2750	2740	2663	2579	3014
		Proportion,%	52.28	51.16	51.30	49.46	54.10
	PUD	PD Reserves, MMboe	3222	3818	3672	3459	3572
		Reserves, MMboe	2038	1538	1519	1755	1999
		Proportion,%	38.75	28.72	29.26	33.66	35.88
	Overseas	Domestic Reserves, MMboe	3802	3781	3708	3341	3333
		Reserves, MMboe	1458	1575	1483	1873	2238
		Proportion,%	27.72	29.41	28.57	35.92	40.17

Table A3. Statistical table of the 1P RPR, 1P RRR and E/D&IR RRR of eight oil companies (2020–2024).

Company	Type		2020	2021	2022	2023	2024	2020–2024 Average
PetroChina	1P RPR	Crude Oil	5.65	6.83	7.08	6.64	6.57	6.55
		Natural Gas	18.11	16.95	15.71	14.76	14.18	15.94
		Oil Equivalent	11.04	11.42	11.07	10.43	10.19	10.83
	1P RRR	Crude Oil	−1.22	1.97	1.39	0.79	0.96	0.78
		Natural Gas	1.05	0.66	0.69	0.87	1.00	0.85
		Oil Equivalent	−0.24	1.37	1.07	0.82	0.98	0.80
	E/D&IR RRR	Crude Oil	0.53	0.66	0.82	0.80	0.74	0.71
		Natural Gas	1.18	1.11	1.36	1.32	1.22	1.24
		Oil Equivalent	0.81	0.87	1.07	1.04	0.97	0.95
ExxonMobil	1P RPR	Crude Oil	10.38	14.61	13.42	12.58	12.61	12.72
		Natural Gas	11.31	11.36	11.46	11.18	11.74	11.41
		Oil Equivalent	10.74	13.31	12.65	12.07	12.32	12.22
	1P RRR	Crude Oil	−5.67	4.95	0.18	0.68	3.31	0.69
		Natural Gas	−1.72	1.06	0.83	−0.03	1.96	0.42
		Oil Equivalent	−4.11	3.39	0.43	0.42	2.87	0.60
	E/D&IR RRR	Crude Oil	0.45	1.22	1.14	0.82	1.34	0.99
		Natural Gas	0.13	0.46	0.73	0.65	0.86	0.57
		Oil Equivalent	0.32	0.91	0.98	0.76	1.18	0.83
Chevron	1P RPR	Crude Oil	8.99	9.23	9.69	8.99	7.02	8.78
		Natural Gas	11.22	10.98	10.99	10.75	9.49	10.69
		Oil Equivalent	9.86	9.96	10.25	9.72	8.03	9.56
	1P RRR	Crude Oil	0.45	0.95	0.96	0.88	−0.29	0.59
		Natural Gas	1.17	1.35	0.98	0.83	0.33	0.93
		Oil Equivalent	0.74	1.12	0.97	0.86	−0.04	0.73
	E/D&IR RRR	Crude Oil	0.25	0.86	0.80	0.49	0.52	0.58
		Natural Gas	0.17	0.53	0.59	0.26	0.37	0.38
		Oil Equivalent	0.22	0.72	0.71	0.40	0.46	0.50
TotalEnergies	1P RPR	Crude Oil	10.27	10.68	10.32	9.69	11.14	10.42
		Natural Gas	13.28	12.73	9.77	15.00	14.49	13.05
		Oil Equivalent	11.73	11.72	10.11	11.66	12.43	11.53
	1P RRR	Crude Oil	0.64	1.07	0.77	0.60	1.92	1.00
		Natural Gas	0.70	0.33	−2.79	2.87	1.06	0.43
		Oil Equivalent	0.66	0.74	−0.86	1.41	1.57	0.71

Table A3. *Cont.*

Company	Type		2020	2021	2022	2023	2024	2020–2024 Average
TotalEnergies	E/D&IR RRR	Crude Oil	0.04	0.59	0.13	0.01	0.79	0.31
		Natural Gas	0.26	0.60	0.30	0.18	0.23	0.31
		Oil Equivalent	0.14	0.60	0.20	0.08	0.57	0.32
Shell	1P RPR	Crude Oil	6.98	7.21	8.51	8.46	8.42	7.92
		Natural Gas	7.20	8.06	9.06	9.97	9.36	8.73
		Oil Equivalent	7.09	7.62	8.78	9.19	8.87	8.31
	1P RRR	Crude Oil	0.03	0.94	1.18	0.97	0.94	0.81
		Natural Gas	−1.12	1.47	1.21	1.44	0.75	0.75
		Oil Equivalent	−0.53	1.20	1.20	1.20	0.85	0.78
	E/D&IR RRR	Crude Oil	0.07	0.33	0.18	0.18	0.18	0.19
		Natural Gas	0.06	0.43	0.43	0.12	0.69	0.35
		Oil Equivalent	0.07	0.38	0.30	0.15	0.43	0.27
BP	1P RPR	Crude Oil	13.88	14.2	9.02	9.21	8.68	11.00
		Natural Gas	13.87	13.21	6.82	6.64	5.62	9.23
		Oil Equivalent	13.89	13.78	7.88	7.85	7.09	10.10
	1P RRR	Crude Oil	−0.07	0.25	−12.83	0.38	0.89	−2.28
		Natural Gas	−0.02	0.05	−6.80	0.62	−0.02	−1.23
		Oil Equivalent	−0.05	0.16	−9.73	0.51	0.42	−1.74
	E/D&IR RRR	Crude Oil	0.40	0.46	0.20	0.29	0.39	0.35
		Natural Gas	0.49	0.26	0.10	0.21	0.16	0.24
		Oil Equivalent	0.44	0.37	0.15	0.25	0.27	0.30
Eni	1P RPR	Crude Oil	11.41	11.02	11.51	11.01	10.39	11.07
		Natural Gas	10.39	10.62	11.02	10.23	10.37	10.53
		Oil Equivalent	10.89	10.79	11.25	10.62	10.40	10.79
	1P RRR	Crude Oil	0.72	0.14	0.61	0.83	0.61	0.58
		Natural Gas	−0.06	0.93	1.20	0.47	1.57	0.82
		Oil Equivalent	0.43	0.55	0.93	0.64	1.13	0.73
	E/D&IR RRR	Crude Oil	0.13	0.13	0.50	0.18	0.18	0.22
		Natural Gas	0.04	0.14	0.16	0.17	0.94	0.29
		Oil Equivalent	0.08	0.13	0.32	0.17	0.59	0.26
Equinor	1P RPR	Crude Oil	6.68	7.29	7.52	7.14	7.20	7.17
		Natural Gas	8.22	7.80	7.42	7.54	8.76	7.95
		Oil Equivalent	7.41	7.54	7.47	7.33	7.97	7.54
	1P RRR	Crude Oil	−0.07	1.30	0.74	1.29	0.78	0.81
		Natural Gas	−0.02	0.97	0.78	0.75	2.27	0.95
		Oil Equivalent	−0.05	1.14	0.76	1.03	1.51	0.88
	E/D&IR RRR	Crude Oil	0.12	0.68	0.33	0.78	0.09	0.40
		Natural Gas	0.26	0.18	0.47	0.64	0.26	0.36
		Oil Equivalent	0.18	0.43	0.40	0.71	0.18	0.38

Table A4. Comparative analysis of unit Exploration/Development/Lifting Costs for eight oil companies (2020–2024, Unit: USD/boe).

Company	Cost Type	2020	2021	2022	2023	2024
PetroChina	Exploration Costs per boe of Production	3.29	3.65	3.45	3.76	3.36
	Development Costs per boe of Production	13.04	13.83	14.97	14.87	12.85
	Lifting Costs per boe of Production	13.85	16.56	21.10	19.87	18.09
ExxonMobil	Exploration Costs per boe of Production	0.87	0.89	0.77	0.67	0.78
	Development Costs per boe of Production	8.14	6.65	10.68	13.47	12.66
	Lifting Costs per boe of Production	13.01	16.00	20.70	17.31	16.27

Table A4. *Cont.*

Company	Cost Type	2020	2021	2022	2023	2024
Chevron	Exploration Costs per boe of Production	0.77	0.60	0.85	0.88	0.83
	Development Costs per boe of Production	9.44	7.93	10.01	13.42	12.13
	Lifting Costs per boe of Production	9.81	10.36	11.63	11.27	10.96
TotalEnergies	Exploration Costs per boe of Production	1.15	1.15	1.06	1.44	0.98
	Development Costs per boe of Production	6.85	7.56	7.66	10.05	11.43
	Lifting Costs per boe of Production	9.41	14.72	21.86	21.62	20.83
Shell	Exploration Costs per boe of Production	1.91	1.64	2.24	2.90	1.80
	Development Costs per boe of Production	10.82	7.54	11.15	12.48	15.58
	Lifting Costs per boe of Production	10.95	13.31	16.76	14.06	13.16
BP	Exploration Costs per boe of Production	1.07	0.72	1.17	1.57	2.17
	Development Costs per boe of Production	8.64	8.45	10.88	13.32	13.34
	Lifting Costs per boe of Production	9.59	14.57	14.52	9.29	9.98
Eni	Exploration Costs per boe of Production	1.01	1.45	1.97	2.20	1.80
	Development Costs per boe of Production	9.95	9.49	13.52	19.63	19.57
	Lifting Costs per boe of Production	7.90	9.75	11.49	10.98	11.43
Equinor	Exploration Costs per boe of Production	1.99	1.49	1.62	1.85	2.07
	Development Costs per boe of Production	9.87	10.35	10.46	11.91	13.64
	Lifting Costs per boe of Production	7.73	8.69	9.37	10.06	9.66

Data source: S&P Energy Portal.

Table A5. Statistical table of FCF after F&D costs per boe, pre-tax profit per boe, and Recycle Ratio of eight oil companies (2020–2024).

Company	Operating Performance Indicator	2020	2021	2022	2023	2024
PetroChina	FCF after F&D Costs per boe	2.50	13.84	19.30	12.22	14.92
	Pre-tax profit per boe	4.71	16.89	21.03	18.10	21.24
	Recycle Ratio	−0.22	2.59	2.45	1.55	2.14
ExxonMobil	FCF after F&D Costs per boe	6.04	16.80	25.55	13.25	−14.09
	Pre-tax profit per boe	−17.14	18.80	37.56	25.70	23.57
	Recycle Ratio	−5.40	13.41	3.56	1.33	1.61
Chevron	FCF after F&D Costs per boe	3.50	21.22	32.38	15.07	17.68
	Pre-tax profit per boe	−0.67	21.62	43.18	23.16	24.81
	Recycle Ratio	0.82	4.78	5.31	1.45	1.59
TotalEnergies	FCF after F&D Costs per boe	4.28	14.32	22.11	12.60	10.07
	Pre-tax profit per boe	−4.86	19.88	34.86	26.13	23.57
	Recycle Ratio	1.02	2.88	3.65	5.45	3.87
Shell	FCF after F&D Costs per boe	3.88	17.90	21.75	13.38	10.21
	Pre-tax profit per boe	−16.15	17.96	42.15	21.50	22.97
	Recycle Ratio	−0.55	5.51	6.03	4.03	2.31
BP	FCF after F&D Costs per boe	−7.19	13.23	18.67	10.74	12.87
	Pre-tax profit per boe	−15.21	18.22	36.09	17.69	15.28
	Recycle Ratio	1.76	1.57	2.94	1.65	1.47
Eni	FCF after F&D Costs per boe	4.47	14.04	20.98	6.62	4.69
	Pre-tax profit per boe	−1.57	24.57	40.30	22.19	18.96
	Recycle Ratio	0.61	1.95	5.05	1.55	3.54
Equinor	FCF after F&D Costs per boe	4.91	16.86	35.24	12.65	9.22
	Pre-tax profit per boe	−5.50	46.12	111.37	47.53	41.86
	Recycle Ratio	−0.08	6.51	9.07	4.07	4.65

Data source: S&P Energy Portal.

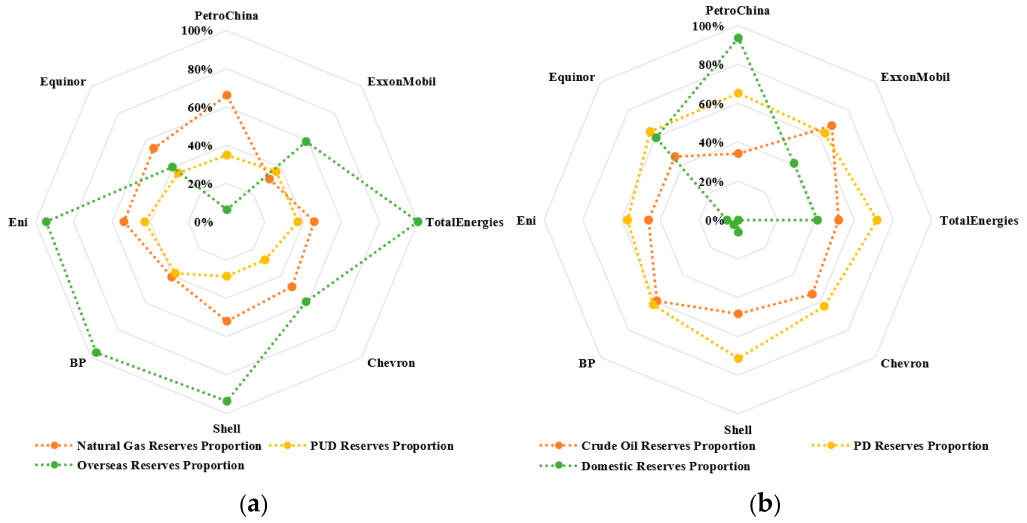


Figure A1. (**a**) 1P Reserves Composition Chart: Gas and PUD and Overseas Reserves Distribution (2024, eight benchmark companies); (**b**) 1P Reserves Composition Chart: Oil and PD and Domestic Reserves Distribution (2024, eight benchmark companies). Note: (**a**) and (**b**) are complementary panels; for each classification the two shares sum to unity (within rounding). Data source: company SEC annual reports, compiled by the authors.

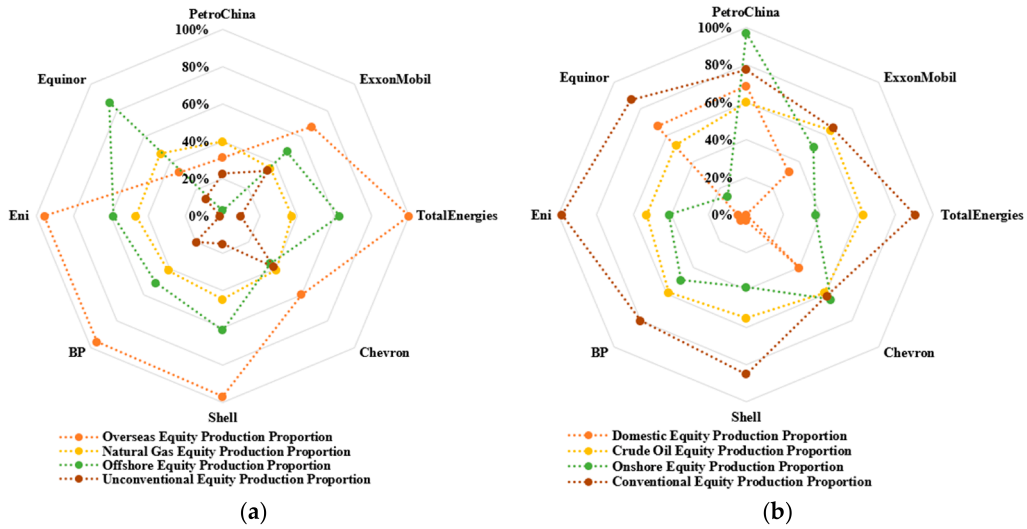


Figure A2. (**a**) Equity Production Composition Chart: Overseas and Natural Gas and Offshore and Unconventional Equity Production Proportion Distribution (2024, eight benchmark companies); (**b**) Equity Production Composition Chart: Domestic and Crude Oil and Onshore and Conventional Equity Production Proportion Distribution (2024, eight benchmark companies). Note: (**a**) and (**b**) are complementary panels; for each classification the two shares sum to unity, (within rounding). Data source: Rystad Energy.

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