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Decarbonizing Upstream Lifting Costs: Strategic Levers and Field Realities

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ABSTRACT

The article is devoted to the fact that under the conditions of a rapid carbon price increase, the traditional reputational risks of oil and gas companies acquire a distinctly economic character. At the same time, institutional investors demand reporting on the carbon footprint, creating a dual incentive to reduce lifting costs and the CO_2-intensity of production simultaneously. This study aimed to identify and assess the key strategic levers for decarbonizing upstream operations, considering real field constraints. The novelty of the work lies in its comprehensive interdisciplinary approach, which combines a techno-economic analysis of electrification (shore-to-offshore, wind, and solar solutions), an assessment of the economic payback of zero-flaring and LDAR programs, digital-twin modeling with AI optimization, as well as a techno-economic evaluation of CCUS/EOR and the energy efficiency of lifting systems. The main findings show that the shift to electrification reduces specific emissions by up to 86% and, when considering total CAPEX + OPEX, is economically more advantageous than traditional electricity procurement; the elimination of flaring and control of methane leaks can abate up to 40% of industry-wide emissions with neutral or negative impacts on lifting costs; digital twins and AI optimization provide an additional 15–25% reduction in fuel consumption and leaks without well shutdowns. At the same time, the effectiveness of each of these levers depends directly on the infrastructural, regulatory, financial, and personnel constraints of a given field. This article will be helpful to operators of upstream assets, ESG strategy developers, and investment analysts in the oil and gas sector.

Key words: decarbonization, lifting costs, electrification, zero-flaring, LDAR, digital twin, CCUS, EOR, energy efficiency, oil and gas industry.

Introduction

The sustainability of oil and gas companies in the mid-2020s is increasingly determined by the euro cost per barrel and the rapidly rising "carbon price." Whereas in 2020 the average cost of an EU ETS allowance was only €21.92/t CO_2 [1], by 2024 it had risen to €67.25/t, and the average forecast for 2025 stands at €76.75 /t CO_2 [2]; analysts expect a further increase to €149/t by 2030 [3]. Such a price "multiplier" transforms methane leaks, flaring, and the operation of gas turbines on platforms from reputational risks into direct expenses comparable to traditional lifting costs. Additional pressure comes from investors: 48% of institutional market participants have already publicly committed to reaching net zero by 2050, and 71% have explicitly incorporated climate risks into their investment policies [4]. For operators, this means the need to demonstrate not only a low dollar cost of production but also a declining specific CO_2-equivalent emission per barrel.

Concurrently, the very economics of upstream have changed. After a dramatic cut in investments to approximately $300 billion in the pandemic year 2020, the industry returned to active growth: total CAPEX exceeded $600 billion in 2024, and by 2030, roughly $738 billion per year will be required to sustain supply [5]. However, a swift return to "cheap barrels" has not materialized. According to Rystad Energy's calculations, the average breakeven price for new non-OPEC projects rose to $47/barrel Brent in 2024, 5% higher than a year earlier [6]. Thus, lifting costs have reached a new level where financial discipline meets active decarbonization demands.

In summary, 2020–2025 has created a dual incentive to change upstream practices. On the one hand, rising CAPEX and project cost inflation require strict control of lifting costs. On the other hand, the escalation of carbon prices and the strengthening of ESG filters increase business sensitivity to methane leaks, the efficiency of energy equipment, and the choice of power sources. The industry is entering a phase where reducing the carbon footprint becomes not a cost but a condition for preserving the competitiveness of production—this strategic viewpoint underpins the subsequent analysis of technologies and field constraints presented in the following sections.

Materials and Methodology

The study is based on an interdisciplinary analysis of 28 key sources covering carbon allowance economics, ESG investment trends, and techno-economic assessments of decarbonization solutions. EU ETS data—actual prices for 2020–2024 [1], forecasts for 2025 [2], and long-term projections to 2030 [3]—were used to construct price scenarios. The industry investment landscape is characterized by the results of Robeco's survey on institutional net-zero commitments [4]. At the same time, upstream CAPEX dynamics are drawn from the IEF/S&P report on industry needs and historical data for 2020–2024 [5]. Economic indicators for the cost of new non-OPEC projects per year of production and lifting costs were sourced from Rystad Energy [6].

The methodological section comprises several complementary stages. First, a comparative techno-economic analysis of the electrification of platforms and coastal facilities was conducted: evaluations of specific emissions reductions and calculations of total CAPEX + 10-year OPEX for cable solutions, hybrid wind systems, and PV–BESS configurations, based on data from Rystad Energy [7], Orcadian [8], and Energiesmedia [9]. Second, a systematic review of flaring and methane leaks identified the payback potential of LDAR programs and compression installations, where the pricing model was built on contracts for the sale of conserved gas and complemented by IEA global emissions data [10], [11]. The third stage involved the assessment of digital twins and AI optimization: analysis of reductions in fuel consumption and leaks based on practical cases from Mössinger [12] and Statfjord C [13], as well as modeling the impact of a “live” thermal balance on equipment selection. The fourth stage covered techno-economic modeling of CCUS/EOR solutions, considering the federal 45Q credit and incremental oil production parameters: calculations of specific CO_2-intensity reductions relied on estimates from CATF [17] and DOE [16]. The fifth stage—the audit of the energy efficiency of lifting and fractional systems—included a comparison of VFD implementation and modern ESP systems according to data from Halliburton [18], Baker Hughes [19], and scholarly publications on drive-system optimization [20].

Results and Discussion

Energy combusted directly on the fields and routine flaring account for most emissions during production, thus representing the most significant reserve for reducing carbon intensity without sacrificing profitability. Experience shows that the decarbonization of these operations can proceed in parallel with the control of lifting costs if the levers are selected based on the actual energy and infrastructure constraints of a given field.

The most significant lever is the electrification of the power supply. The conversion of platforms to shore-to-sea cable or a hybrid system comprising a floating wind farm and backup gas engines has already demonstrated the ability to reduce specific emissions from 8,4 to 1,2 kg CO_2e per barrel-equivalent—that is, by 86% [7]. The difference between capital investments in transformers, cable, and wind clusters, and the avoided expenditures on fuel gas and carbon allowances determines the economics of this solution. Study [8] shows that the combined CAPEX + 10-year OPEX of such a solution is more than 25% lower than the “standard” scenario of purchasing electricity from shore, with an absolute net present savings of ≈ 2 billion USD across nine platforms. Converted to lifting costs, this yields a reduction in the operational component with a zero or moderately positive margin to total price during the first five years of operation, after which the effect becomes purely negative, thanks to savings on fuel and allowances. An additional advantage is extending the assets’ design life, which spreads the inevitable capital expenditures over a larger production volume and further lowers the specific lifting cost. If the project is onshore or near the coastline, the same objective is commonly achieved by pairing a solar power plant with an energy storage system. The average capital rate for utility-scale PV already fell to 1,734 $/kW in 2023 and is forecast to drop to 490 $/kW by 2030, while fixed operating expenses amount to only 15,9 $/kW·yr versus 34,7 $ for traditional technologies [9].

The second group of measures targets directly eliminating “pure” carbon sources—flaring and methane leaks. According to [10], in 2023, some 148 billion m^3 of associated gas were flared worldwide; eliminating routine flaring would cut 381 million t CO_2-equivalent per year. At the average contract price for the sale of conserved gas, operators can fully amortize the infrastructure for gas collection and compression: internal calculations by major operators show a discounted benefit from additional revenue. At the same time, net operating costs increase only marginally. The case for methane is even more favorable. Study [11] demonstrates that 40% of the industry’s 120 million tons of annual emissions can be eliminated at no net cost—that is, the revenue from sold gas offsets capital and service expenses—while the oil and gas sector has the most tremendous potential, as shown in Fig. 1.

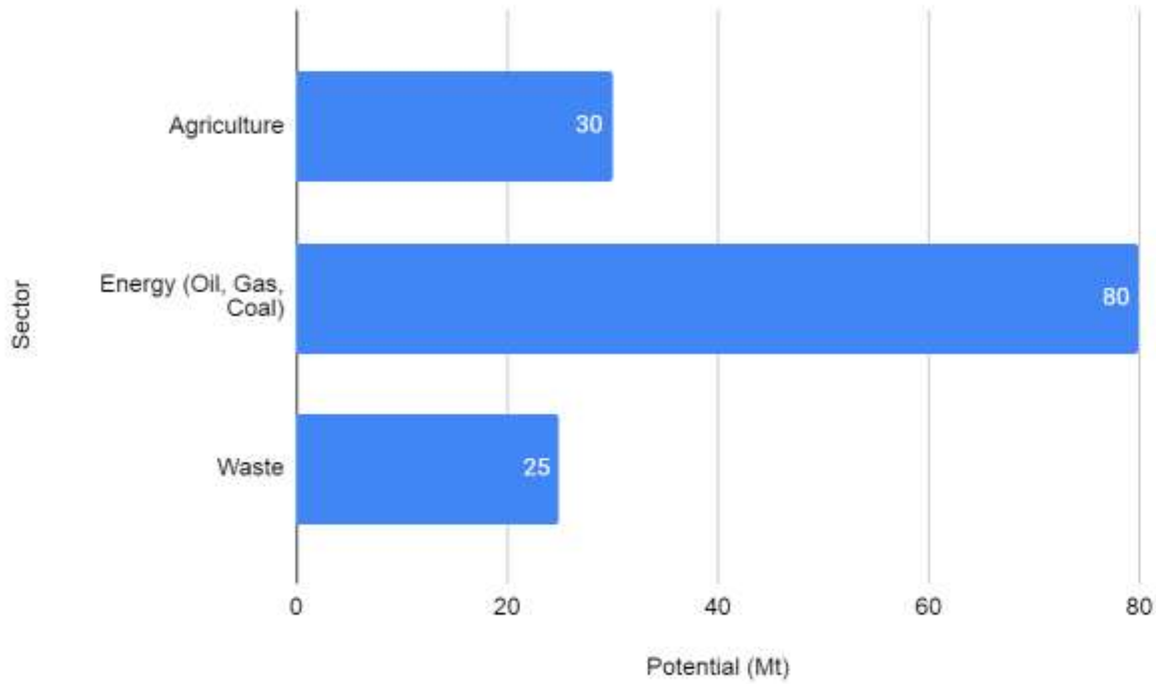

Fig. 1. Methane abatement potential to 2030 [11]

From a practical standpoint, this involves a quarterly LDAR program, replacing pneumatic devices with zero-leak valves, and installing vapor recovery units. Thus, the electrification of the power supply and rigorous control of flaring and methane leaks offer a real potential for reducing production emissions with neutral or negative impacts on lifting costs.

A digital twin connected to well telemetry streams and process-AI transforms each installation into a computable system wherein fuel consumption and background methane emissions become direct parameters of the objective function. The largest operators already record in-field reductions in specific emissions of 15–25% following the deployment of continuous AI optimization of pumping, separation, and compression regimes [12]. This approach simultaneously reduces unplanned downtime and shifts some emergency repairs to scheduled maintenance, yielding net savings on a significant asset; when allocated to production, this corresponds to a reduction in lifting costs—a decrease relative to average operating cost. A representative example is Statfjord C, where a steam-turbine scheme, optimized via a “live” thermal-energy-balance digital twin of the platform, enabled the decommissioning of two gas turbines; the result was – 95 000 t CO_2 per year at an unchanged operating budget [13]. Overall, digital twins and AI analytics serve as a “fine” lever: they require virtually no well shutdowns and pay back quickly through savings on fuel, allowances, and maintenance, lowering the specific lifting cost depending on field maturity.

Integrating renewables via managed microgrids and storage systems closes the next layer of emissions, those remaining even after regime optimization. The large-scale Belridge Solar project in California combines 850 MWth of solar parabolic trough and 26,5 MW PV, entirely replacing natural gas for steam generation and reducing emissions by 376,000 t CO_2-equivalent annually [14]. At the opposite end of the scale, the remote New Stuyahok well cluster in Alaska: here, a 500 kW PV + 540 kW·h BESS hybrid reduced diesel consumption by 24% (~ 30 000 gal/yr) and cut 357 t CO_2-equivalent while saving 180 000 $ in fuel costs per annum [15]. Expressed per unit of production for a small field, this equates to a reduction in lifting costs and full equipment payback within four to five seasons. Crucially, the microgrid enables a “diesel-off” mode, thereby eliminating background flaring and some methane leaks—an effect difficult to achieve through digital control alone.

The combined application of these two levers logically continues the trajectory set by electrification and zero-flaring. First, the digital twin reduces energy consumption and identifies the optimal load profile, and then the microgrid replaces the residual fossil flow with low-carbon energy buffered in the BESS.

CO_2 injection for permanent storage or EOR-enhanced oil recovery remains the most CAPEX-intensive lever, yet it delivers a singular leap in the carbon balance of mature assets. The federal 45Q credit now pays 85$/t for geological storage and 60$/t when CO_2 is used in EOR [16]. A typical EOR cycle requires ~ 0,3 t CO_2 per incremental barrel of oil, of which ~ 0,27 t is permanently sequestered in the pore space, equivalent to a 63% reduction in “well-to-wheel” emissions per barrel (Fig. 2) [17].

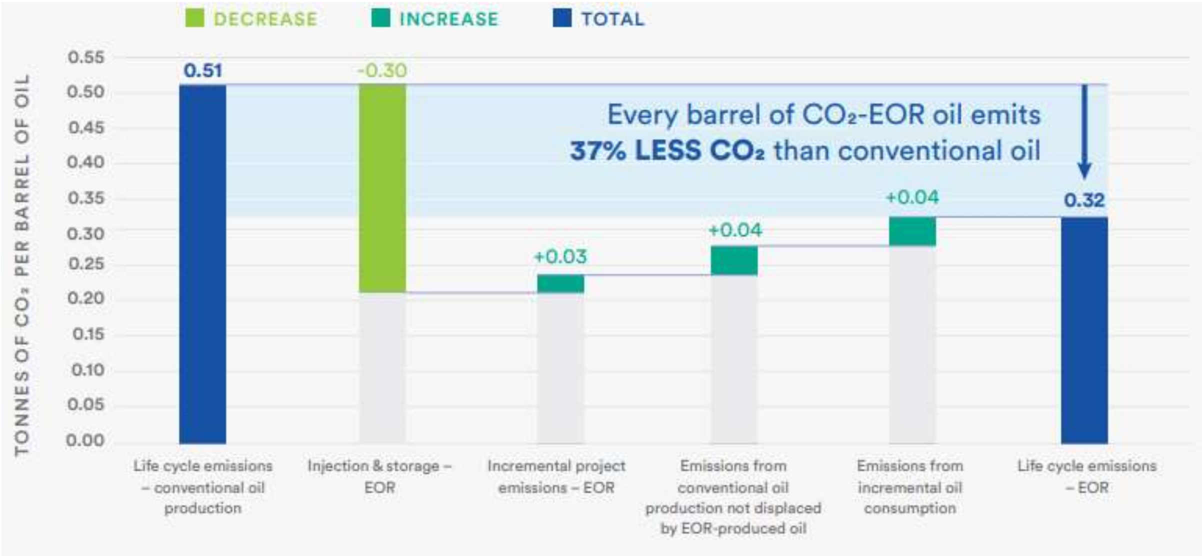

Fig. 2. Net CO2 Emissions Per Tonne Of CO2 Stored Through EOR [17]

In practice, the energy expenditures of the injection compressor and gas recirculation add only a minor component to operating costs, while the tax incentive and production uplift more than offset them.

The "lightest" side of decarbonization is optimizing lifting systems, where equipment energy efficiency immediately translates into fuel savings. Halliburton's Zeus technology yielded an electric platform for hydraulic fracturing that delivers on average 30% faster transition times and 11% more monthly HHP pumping hours [18]. This means more pumping hours, more lateral feet drilled, and greater savings for operators. Equally crucial over the production cycle is that surface efforts lower the well's energy profile: integrating permanent magnet motors and VFDs in ESP systems reduces electrical consumption by 30% according to [19]. A more comprehensive audit of electric-driven loads in oil processing showed up to 67% savings after installing VFDs on fans, pumps, and compressors, with a payback of < 1 year and zero production downtime [20].

Thus, heavy CAPEX-intensive CCUS/EOR solutions can eliminate up to one-third of emissions with minimal cost increases. At the same time, "fine" optimization of lifting and fracking systems delivers rapid adverse effects on lifting costs by locking in consistent energy and allowance savings. Together, these levers close the carbon gap after electrification and zero-flaring, rendering the production portfolio cleaner and more resilient to fuel and carbon-price volatility.

The decarbonization effectiveness of any production technology is determined by its theoretical potential and how well it fits within the constraints of site, market, and organization. The first and often decisive constraint is physical infrastructure. On the Norwegian shelf, full power-from-shore conversion was completed at the Utsira High hub: expenditures of 1,08 billion NOK included a 28-km cable and upgrade of distribution boards. At the same time, the annual carbon effect reaches 1,2 million t CO_2-equivalent [21]. However, even here, the power transfer to platforms is limited to 1 GW in 2025, with a risk of capacity shortfall after 2030 when demand rises to 2 GW, and the North Sea market will face upward pressure on wholesale electricity prices [22].

As stated in the introduction, the second level of restrictions is regulatory, and the third is capital: CAPEX in the industry will exceed $600 billion in 2024 and grow to $738 billion by 2030 [5]. Against this backdrop, only decarbonization projects whose NPV sensitivity to Brent and EUA prices can withstand a stress scenario are approved. Conversely, integrating floating wind farms remains costly: fixed offshore installations average 230 USD/MWh, floating — 320 USD/MWh, which at current discount rates raises the barrier to entry and postpones mass adoption to assets with the highest carbon penalty [23]. Thus, the financial viability of levers depends directly on the configuration of "oil + carbon" prices and financing costs.

Finally, any technical plan comes down to people. Transitioning to modern technologies requires specialists with work permits and appropriate qualifications. At the same time, digitalization drives demand for data and AI competencies: 92% of executives view reskilling as a competitive advantage, yet only 29% invest in employee retraining, and this discrepancy has been named the main barrier to digital-twin implementation [24]. Without systematic personnel development, the risks of shutdowns and errors rise faster than emissions decline.

Thus, infrastructure connectivity, regulatory incentives, capital availability, and workforce readiness form an interrelated matrix through which any decarbonization lever must pass. Ignoring even one of these blocks turns potential carbon savings into sunk costs. In contrast, comprehensive consideration of constraints allows emissions to be reduced with neutral or negative impacts on lifting costs, confirming the economic logic of decarbonization outlined in previous sections.

The legislative environment that sets the carbon price and rules for methane and flared gas now covers the majority of global production and is rapidly tightening, rendering the technological levers described above necessary for maintaining competitive lifting costs. In the European Union, this core is formed by the fourth phase of the EU ETS: following the recent 2024 reform, the overall cap was lowered to 1,386 Mt CO_2e, coverage was extended to maritime transport, and the average auction price of allowances for the first four months of 2025 holds at around €65 (≈ $70) per tonne [25].

Northern European producers intensify the pressure with their taxes. Norway, in addition to ETS participation, already levies a carbon excise of 761 NOK/t CO_2 for burning gas and diesel on the shelf; the government roadmap provides for nearly doubling the rate by 2030, making every avoidable leak more expensive than electricity delivered via subsea cable [26]. Meanwhile, the primary source remains turbines in Norway, as shown in Fig. 3.

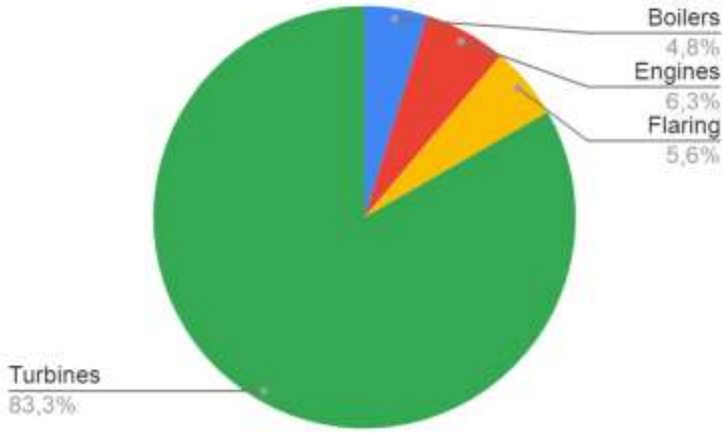

Fig. 3. CO_2 emissions in Norway from petroleum activities in 2023 by source [26]

The United Kingdom, having left the EU ETS, launched its own emissions trading scheme and simultaneously enshrined in the North Sea Transition Deal a legally binding target—50% reduction in production emissions by 2030 versus 2018; platform electrification was named the key instrument, and the government committed to removing infrastructure barriers and creating support models for CCUS [27].

Canada is following the same course: existing federal methane regulations are being revised to achieve a 75% reduction by 2030, and at the end of 2024, a sectoral cap plan was published requiring a 35% reduction in direct upstream emissions below 2022 levels [28].

Horizontal initiatives bridge the space between jurisdictions. The non-binding but obligating Global Methane Pledge has already been endorsed by most countries worldwide; the IEA calculated that existing and announced regulations, if fully implemented, could cut industry emissions by 20% by 2030 from the 2023 baseline, with about 70% of global gas and oil production falling under regulatory coverage [11]. Every new investment inevitably faces a direct ETS/tax price or future methane and flaring obligations, affecting the calculated cost base already at the FID stage.

Thus, the legislative landscape establishes a continuous "carbon rent" while introducing quantitative bans on routine flaring and leaks. These rules complete the economic logic of the previous sections: projects that integrate electrification, digital methane control, and clustered CCUS in advance minimize future tax and price risk, whereas reliance on traditional diesel and open flaring fails investment committee scrutiny, even if the base lifting cost remains low.

Conclusion

The conducted analysis demonstrates that the decarbonization of oil and gas production operations in the short term can not only reduce carbon intensity but also support or even improve lifting-cost metrics. Under a rapid increase in the carbon price—from 21.92 €/t CO_2 in 2020 to more than 67 €/t in 2024 and a forecasted 76.75 €/t in 2025—traditional reputational risks become tangible expenses. Concurrently, in response to CAPEX rising to over 600 billion USD in 2024, the market demands stricter control of unit-of-barrel costs. In this context, strategic decarbonization levers become not an additional burden but a critical element of upstream project competitiveness.

The key technological pathways identified herein fall into three successive stages. First, the electrification of power supply—using shore cables, wind turbines, or solar installations—reduces specific emissions by up to 86%. At the same time, a cumulative CAPEX + OPEX calculation shows that such solutions are more economical than market-purchased electricity. Simultaneously, measures for eliminating flaring and controlling methane leaks yield significant abatement savings via conserved and sold gas: up to 40% of annual emissions can be eliminated without increasing net operating costs. Second, digital twins and AI-driven process optimization stabilize and further reduce fuel consumption and leaks, achieving up to 25% reductions in specific emissions without well shutdowns and delivering payback through savings on fuel, allowances, and maintenance. The third step is the integration of renewables into managed microgrids with energy storage, entirely replacing backup diesel generator sets and eliminating background flaring; for mature assets, the implementation of CCUS/EOR enables the removal of up to one-third of emissions with minimal impact on operating costs, thanks to the 45Q tax incentives.

However, the effectiveness of each of these levers depends on real constraints: physical infrastructure, the regulatory environment, available capital resources, and personnel qualifications. The example of Norway's Utsira High and other Northern European projects illustrates power-capacity limits and rising electricity costs. At the same time, EU ETS requirements, national carbon excises, and methane-reduction commitments render decarbonization a prerequisite for investment attractiveness. Moreover, insufficient focus on specialist reskilling hampers the adoption of digital solutions: without systematic personnel development, any optimization plans risk becoming unplanned expenditures.

Thus, a comprehensive approach—combining electrification, zero-flaring, LDAR programs, digital twins, microgrids with BESS, and CCUS/EOR—enables the reduction of the production carbon footprint with neutral or negative impacts on lifting costs. Integrating these technologies into the FID-stage decision-making model becomes not a luxury but an imperative for maintaining the financial resilience and competitiveness of upstream assets under increasingly stringent "carbon pricing" and environmental regulations.

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