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SUPPORTING SUSTAINABLE BUSINESS DEVELOPMENT

Monograph

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The monograph examines the issues of implementing innovative digital technologies in businesses that develop according to the principles of sustainable development and compliance, as well as in companies in such important sectors of the national economy of Ukraine as the oil and gas industry and banking services. Businesses that develop on the principles of sustainable development (ESG) and compliance imperatives ensure their competitiveness, positively affecting the environment and society. At the same time, the idea is that the effective implementation of ESG and compliance should be assisted by business analytics and big data systems that allow for improved analysis of the company's financial indicators and balance sheet, allow for the creation of multidimensional profit and loss reports, and also help understand cash flow, determine the most relevant financial indicators, assess potential, and make management decisions to improve the company's performance. An example of modeling the net present value (NPV) of drilling programs is given, which showed that reducing the WACC from 20% to 15% increases the NPV of a 12-year program by 36% - more than a 15% reduction in initial capital costs. For the first time in OGI conditions in Ukraine, a dual-chain learning model was built, which simultaneously describes the learning curve of horizontal drilling (Ld) and HF (Lh). The inclusion of a multiplicative productivity function allows us to quantitatively assess the synergistic effect. The emphasis is on the fact that digitalization opens up significant opportunities for banks to optimize internal processes. The use of big data and artificial intelligence helps analyze customer behavior, predict risks and develop products that best meet consumer needs. Blockchain technologies provide transparency in financial transactions and protection against fraud. By combining advanced technologies such as blockchain and artificial intelligence with a value-based risk culture and a proactive approach to ESG and regulatory compliance, banks can successfully adapt to the challenges of the digital age.This comprehensive approach serves as a model for implementing resilient, secure, and transparent digital ecosystems that can withstand macroeconomic challenges and meet the growing needs of society.

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INVESTMENT CLIMATE AND TECHNOLOGICAL POTENTIAL OF UKRAINE'S OIL AND GAS INDYSTRY

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State and Structural Characteristics of Ukraine's Oil and Gas Indystry

The oil and gas indysrty (OGI) is one of the key sectors of the Ukrainian economy, on whose condition the country's energy security, its political stability in the international market, the balance of payments, and the competitiveness of national industry directly depend. By various estimates, the share of oil and natural gas in the structure of primary energy consumption exceeds 50%, while domestic production satisfies approximately 30% of the country's needs [1, p. 12; 2, p. 47]. At the same time, over the past decades, the industry has shown a persistent downward trend in production, creating an ever-deeper dependence on imports and increasing the country's vulnerability to external price and geopolitical shocks.

However, Ukraine's resource base remains quite substantial. According to the State Service of Geology and Suboil of Ukraine, proven natural gas reserves of categories A+B+C1 amount to approximately 1 trillion m³, and projected resources, including unconventional deposits (tight sandstones, shale formations, coalbed methane), reach 5–7 trillion m³ [3, p. 8]. With these indicators, Ukraine ranks third in Europe, behind only Norway and the Netherlands [4, p. 23]. However, the realisation of this potential remains extremely low: in 2023, natural gas production amounted to 18.8 billion m³ compared to the peak of 68 billion m³ in 1975 [5]. While it is clear that deposits have depleted a significant portion of their resource over this period, the gap between available reserves and actual production is, in essence, a measure of the industry's unrealised potential, and removing barriers to its development is a key objective of this study.

Oil and gas condensate production also demonstrates a prolonged declining trend. In 2023, it amounted to 1.8 million tonnes of oil and 1.2 million tonnes of condensate, whereas in the mid-1990s, oil production exceeded 4 million tonnes [6, p. 34]. The primary cause is the depletion of the main productive formations of the Dnieper-Donets Basin (DDB) – the country's principal oil and gas bearing region [7, p. 115]. This means that conventional development and drilling methods are no longer capable of ensuring acceptable hydrocarbon recovery rates from reservoirs; accordingly, further development of such fields and reservoirs requires more technologically advanced and complex methods of both well construction and production processes. The only path to development is therefore increasing the oil and gas recovery factor from existing reservoirs, which necessitates the active application of new drilling and stimulation technologies. Below, we will examine horizontal drilling, sidetrack drilling, and the stimulation technology of hydraulic fracturing (HF) and lateral horizontal sidetrack drilling (LHS), which are currently the most relevant for Ukraine.

Among Ukraine's oil and gas bearing regions, three main areas can be identified. The Dnieper-Donets Basin (DDB) accounts for approximately 90% of gas production and 70% of oil production and forms the basis of the current production potential [8, p. 56]. The Carpathian oil and gas region is characterised by a significant level of field depletion and is gradually losing its industrial potential. The Black Sea region, which has significant potential for offshore fields, has effectively been removed from economic circulation since 2014 [9, p. 7]. Offshore areas of the Black and Azov Seas remain promising; however, their development requires significant capital investment and entails elevated technological risks, making them attractive only under favourable investment climate conditions [10, p. 44].

Table 1. Dynamics of Hydrocarbon Production in Ukraine, 2015–2023.

Indicator	2015	2017	2019	2021	2022	2023
Gas, billion m³	19.9	20.5	20.7	19.8	18.5	18.8
Oil, million tonnes	2.2	2.1	2.0	1.9	1.8	1.8
Condensate, million tonnes	1.4	1.3	1.3	1.2	1.2	1.2
Number of wells, units	810	785	760	741	718	695

Source: compiled by the author based on data from the State Setvice of Geology and Suboil of Ukraine [3], NAK Naftogaz [5], Ministry of Energy of Ukraine [6]

Currently, the gas production structure is characterised by excessive concentration. JSC Ukrgazvydobuvannya (UGV), a subsidiary of NAK Naftogaz of Ukraine, provides approximately 73% of total volume [5, p. 18]. The rest of the market is divided among: PJSC Ukrnafta (~10%), DTEK Naftogaz (~8%), and private operators (~9%) [11, p. 31]. Such state monopolisation creates not only market problems but also directly affects the pace of the industry's technological development. Under conditions of dominance by a single inflexible market player, characterised by all the shortcomings of state management — inflexibility in making decisive decisions – across a large number of fields, only stable technological solutions can be maintained. Accordingly, competitive motivation to optimise technologies is virtually absent on these assets, and the oilfield services market remains weak and dependent on order volumes from a single large client [12, p. 78].

The age structure of the well stock should also be noted. According to UGV, over 65% of active wells were drilled before 1990, meaning their average age exceeds 35 years [5, p. 22]. This implies not only the need for constant repair and maintenance but also fundamental technological limitations: Soviet-era wells are largely unsuitable for modern production stimulation methods. According to EY estimates, the costs of maintaining the current production level from depleted wells increase by 5–8% annually, while output continues to decline [13, p. 12]. This creates the so-called "depletion trap": the more funds spent on maintaining old wells, the less remains for introducing new technologies that could halt the decline. In other words, to change the situation, we must already adopt a modern, market-based approach to each individual unit and field, so as to eventually transition into a production growth phase.

Finding and Development costs (F&D) are a key indicator of the economic efficiency of industry investments. For Ukraine, this indicator demonstrates steady growth: while in 2015–2017, unit F&D costs for gas were \$0.8–1.2/thousand m³, in 2021–2023 they rose to \$2.5–4.0/thousand m³ [13, p. 15; 14, p. 6]. This is simultaneously linked to declining reserve additions associated with the overall depletion of accessible conventional deposits and the rising costs of all drilling and production services under wartime conditions [15, p. 3]. Compared with global leaders — the

USA ($0.8–1.5/thousand m³ equivalent) or Norway ($1.2–1.8/thousand m³) [16, p. 44] — Ukraine's figures indicate substantial efficiency reserves, the realisation of which requires, above all, technological modernisation.

When examining the capital expenditure structure of the OGI, we see confirmation of the previously described problems. The predominance of spending on maintenance drilling (55–60% of total CAPEX) and field development (25–30%), with minimal investment in geological exploration (5–8%), is a sign of "consuming" the resource base without the necessary efforts to replenish reserves [5, p. 25; 11, p. 35]. A striking illustration of this situation is the fact that the share of expenditure on stimulation technologies (HF, enhanced oil recovery methods) in the overall CAPEX structure does not exceed 12–15% [17, p. 9], while in the USA this figure reaches 35–45% [18, p. 112]. This gap is not merely statistics: it means that a significant portion of geological reserves, the extraction of which is technically feasible using HF and horizontal drilling, remains unrealised due to a lack of investment and technological competencies.

Table 2. CAPEX Structure of Ukraine's OGI (JSC Ukrgazvydobuvannya), 2019–2023, %.

Expenditure item	2019	2020	2021	2022	2023
Exploration drilling	7	6	5	4	5
Production drilling	58	57	56	54	55
Field development	27	28	29	30	28
Stimulation (HF, EOR)	8	9	10	12	12

Source: calculated by the author based on annual reports of JSC Ukrgazvydobuvannya [17], data from NAK Naftogaz [5]

The full-scale invasion by the Russian Federation in February 2022 significantly complicated the operating environment of Ukraine's OGI and became an unprecedented external shock for the industry. Direct consequences include damage to part of the production and transportation infrastructure in the east of the country, temporary loss of access to certain fields in the combat zone, rising security and insurance costs, an outflow of qualified personnel, and disruption of supply chains for necessary equipment [15, pp. 4–5; 19, p. 11].

At the same time, the military conflict paradoxically highlighted the strategic value of the industry, accelerating the realisation of its priority status. The cessation of transit and the gradual abandonment of gas imports from Russia made increasing domestic production a matter not only of economics but of national security [20, p. 2]. According to NAK Naftogaz estimates, increasing domestic gas production by 5 billion m³/year would fully cover the residual import requirement and significantly strengthen Ukraine's position in future gas negotiations [5, p. 30]. It is precisely in this context that this study is relevant — to draw conclusions about what investment and technological conditions are necessary for accelerated production growth. Such conclusions could change the approach to the OGI structure as a whole and help identify the determining factors for the state apparatus to create such conditions.

From the perspective of investment analysis, the war creates a contradictory context: on the one hand, it increases the strategic and commercial value of successful projects; on the other, it sharply raises the risk premium (country risk premium, CRP) and, accordingly, discount rates, which devalues the NPV of long-term projects. It is precisely this circumstance that is key to understanding the current state of the OGI's investment climate.

Assessment of the Investment Climate of Ukraine's Oil and Gas Indystry.

The concept of "investment climate" is interpreted differently in the literature. In a broad sense, it is the totality of conditions that determine the attractiveness of a particular jurisdiction for capital investment: legal protection of investors, macroeconomic stability, the level of corruption, the quality of the regulatory environment, etc. [21, p. 15; 22, p. 88]. In a narrow, sector-specific context of the oil and gas indysrty, specific factors for the extractive industry are added: stability of the fiscal regime, quality of geological information, subsoil licensing conditions, and availability of service infrastructure [23, p. 202].

In this study, the OGI investment climate is considered as a multidimensional construct encompassing five main blocks: (1) regulatory-legal – the quality of subsoil legislation, licensing procedures, and protection of investor rights [24, p. 5]; (2) fiscal – the level of royalty payments, stability of the tax regime, and availability of incentives for investment in technological modernisation; (3) operational – availability of equipment, transport infrastructure, development of the oilfield services market, and availability of qualified personnel [25, p. 17]; (4) geopolitical – security risks, sovereign credit rating, CRP; (5) technological – the level of adoption of modern production technologies and the innovation activity of operators [12, p. 82].

For external benchmarking, this study uses the Fraser Institute Policy Perception Index (PPI) – an annual index of oil and gas investment attractiveness calculated on the basis of surveys of top managers of extractive companies in over 100 jurisdictions [26]. Despite the fact that this index is subjective in nature (it reflects the perceptions of managers rather than objective legal conditions), its practical value lies in the fact that it is precisely this perception that determines real investment decisions. A company that perceives a jurisdiction as risky will not invest regardless of how attractive the geological prospects may be [27, p. 33].

According to the Fraser Institute Annual Survey 2023, Ukraine received an overall PPI of 42.3/100, corresponding to 78th position among 99 jurisdictions assessed [26]. This is a result that is difficult to consider satisfactory. For comparison: Norway – 82.1, USA (Texas) – 79.4, Canada (Alberta) – 76.8. Even significantly less resource-endowed countries in the region – Poland (51.2) and Romania (48.7) – substantially outperform Ukraine in this ranking [26]. These figures speak eloquently: investors place their capital not where there is oil and gas, but where there are predictable rules of the game.

Component analysis of the PPI ranking reveals a clear picture of the situation: Ukraine receives relatively good scores for natural factors (resource potential – 62.1, quality of geological data – 58.3), while all institutional components are below average [26]. The lowest scores were recorded for "legal uncertainty regarding claims and contracts" (23.1), "instability of the regulatory environment" (28.4), and "level of corruption" (31.7). This score structure is an important analytical signal: the problem of Ukraine's OGI is not geology but the institutional and legal environment [28, p. 45; 29, p. 17].

Table 3. Comparative Assessment of PPI Components for Ukraine and Peer Countries, 2023.

PPI Component	Ukraine	Poland	Romania	Norway
Legal certainty	23.1	52.4	45.8	88.2
Fiscal regime	38.5	49.1	53.2	71.4
Regulatory environment	28.4	47.8	44.1	84.6
Corruption level	31.7	53.6	48.9	91.3
Resource potential	62.1	41.2	55.6	78.4
Geological data	58.3	60.1	56.7	89.1
Overall PPI	42.3	51.2	48.7	82.1

Source: Fraser Institute Annual Survey of Mining and Petroleum Companies, 2023 [26]; author's calculations.

The dynamics of Ukraine's PPI ranking over 2015–2023 reflect an uneven reform path. A certain improvement occurred in 2017–2019, linked to the reform of the natural gas market, the introduction of market-based pricing, and the preparation of a new Subsoil Code of Ukraine [28, p. 48; 30, p. 6]. A sharp deterioration in 2022 was a direct consequence of the full-scale invasion and the associated increase in security risks. A partial recovery in 2023 reflects the industry's adaptation to wartime conditions and the continued operational activity of most companies [15, p. 8].

The fiscal regime for oil and gas production in Ukraine is shaped primarily by the system of royalty payments defined by the Tax Code [31]. Rates are differentiated by hydrocarbon type and depth of occurrence: for gas from deposits up to 5,000 m – 29% (temporarily reduced to 12% in 2015–2016 to stimulate production, later restored to the base level); for deposits deeper than 5,000 m – 14%; for oil – 45%, condensate – 21% [31; 32, p. 28]. The effective tax rate on profitable projects, including VAT, corporate income tax, and other deductions, reaches 65–75% [32, p. 30]. For comparison: in Norway, the total burden is ~78%, but there exists a complex of cost recovery and payment deferral mechanisms that significantly improve project cash flow circulation [33, p. 56].

The biggest problem of the fiscal regime is not so much the absolute level of rates as their instability. In 2014–2023 alone, royalty rates were changed four times [32, p. 32]. Each such change destroys existing financial models, forcing investors to incorporate more conservative development scenarios into their projects. According to EBRD estimates, unpredictable changes to the fiscal regime raise the effective cost of capital for the industry by 1.5–2.5 percentage points [34, p. 14], which, given the already high base discount rate, represents a critical blow to the NPV of long-term projects.

The key indicator of investment climate quality for the purposes of this study is the discount rate (WACC) applied to the evaluation of oil and gas projects in Ukraine. This rate is a function of three components: the risk-free rate (typically linked to US Treasury yields or the NBU rate), the industry risk premium, and the country-specific risk premium (CRP) [35, p. 204]. According to the author's calculations based on the Damodaran methodology, as of end 2023, the WACC for oil and gas projects in Ukraine is 18–22% [35; 36] – one of the highest among European oil and gas jurisdictions. For comparison: the WACC for similar projects in Norway is 7–9%, Poland – 10–12%, Romania – 11–13% [13, p. 18; 33, p. 58].

Table 4. Comparative WACC Characteristics for the OGI in Ukraine and Peer Countries, 2023.

Jurisdiction	Risk-free rate, %	Industry premium, %	CRP, %	WACC, %
Norway	3.5	2.5	0.0	7–9
Poland	5.0	3.0	1.5	10–12
Romania	5.5	3.5	2.0	11–13
Kazakhstan	5.0	4.0	4.5	14–16
Ukraine (2021)	4.5	4.5	7.0	16–18
Ukraine (2023)	4.5	4.5	10–12	18–22

Source: calculated by the author based on the Damodaran methodology [35; 36]; Bloomberg, EBRD [34], NBU [37] data

The practical significance of the difference in discount rates is very easy to underestimate if viewed as an abstract financial parameter. In reality, as will be shown in Section 1.3, reducing the WACC from 20% to 15% – that is, by 5 percentage points – increases the NPV of a typical 12-year field development programme by 36% at the base gas price. This is a greater effect than reducing initial capital expenditure by 15%. Therefore, reforms that improve the investment climate and reduce CRP are a more effective tool for increasing production than direct fiscal incentives or subsidies.

Modelling the Impact of the Investment Climate on Hydrocarbon Production Profitability

Most publications on the investment climate of extractive industries consider its impact on the volume of attracted investments or on profitability through the cost of capital [21, p. 18; 28, p. 51]. Both channels are real and important. However, they do not describe the full mechanism of impact – and it is precisely this gap that serves as the starting point for the conceptual model proposed for consideration.

Based on actual industry experience and case studies, the following conclusion can be drawn: between the quality of the investment climate and the industry's technological progress, there exists a third – far less studied – causal link. A favourable investment climate attracts new independent operators and oilfield service companies, forming a competitive environment. This competitive environment, in turn, accelerates the accumulation of technological experience – a learning effect in the sense of Wright's Law [38, p. 321; 39, p. 1145]. Faster learning reduces unit production costs non-linearly and very substantially, which radically improves the NPV of drilling programmes even with unchanged hydrocarbon prices.

Thus, the full causal chain looks as follows: improvement of the investment climate (↑ PPI) → attraction of new operators and oilfield services → competitive pressure → acceleration of the learning effect (↑ L) → reduction in unit costs (↓ C) → increased profitability (↑ NPV) → production growth → strengthening of energy security. This chain is proposed as the theoretical framework of this study.

For quantitative modelling of the learning effect, Wright's Law, or the "learning curve" [38; 40, p. 56], is used. First described in 1936 in relation to aircraft manufacturing [41], it was subsequently confirmed for a wide range of industrial technologies – from solar panels to shale drilling [39; 42, p. 7]. According to this law, unit costs decrease by a fixed percentage (learning rate L) with each doubling of cumulative production volume:

$$C(Q) = C_1 \cdot Q^{-\alpha}, \text{ where } \alpha = -\log_2(1 - L/100) \quad (1)$$

here C(Q) – unit F&D costs at cumulative production Q; C_1 – costs for the first unit of production; L – learning rate; α – learning exponent. Calibration of the parameter L for Ukraine's OGI was conducted based on analysis of the dynamics of UGV's unit F&D costs for 2015–2023. The obtained estimates – L = 4.5–6.0% for HF operations and L = 2.5–3.5% for drilling operations – fall within the range established by Patterson and Hausman (2019) for the US shale market at an early stage of development [39, p. 1148], which is a methodologically appropriate analogue for Ukraine as a "market entering the curve."

The key conclusion of the base model is counterintuitive for those accustomed to evaluating projects based on the first year alone. At a learning rate of L = 5%, a programme of 100 HF operations yields a 28% reduction in unit costs relative to the starting level. At L = 10% — a 47% reduction. This non-linear relationship means that the first years of the programme are an "investment in learning," and the true value is revealed in the medium-term perspective. This three-phase profile (learning phase → transition phase → scaling phase) is a fundamental feature of any technology programme based on the learning curve [43, p. 204].

For quantitative assessment of the impact of investment climate quality (through the discount rate r) on the NPV of drilling programmes, a typical 12-year programme with W wells per year is considered:

$$NPV = -I_0 + \Sigma^{T}_{t=1} CF(t) \cdot (1+r)^{-t} \quad (2)$$

here CF(t) – cash flow in year t, adjusted for the learning effect; I_0 – initial capital expenditure. Substituting the cost function with the learning curve, we obtain NPV as an explicit function of parameters L, price P, rate r, and drilling rate W. The methodological basis for such modelling was laid by the works of Hausman and Johnston [44, p. 312], Managi et al. [45, p. 88], and Ikonnikova et al. [46, p. 1], who studied learning curves in the American oil and gas industry.

Table 5. Sensitivity Analysis of NPV of a 12-Year Drilling Programme to Discount Rate r and Gas Price P ($ million, W=10 wells/year, L=5%).

r \ P	$200/thous.m³	$240/thous.m³	$280/thous.m³	$320/thous.m³	$360/thous.m³
r = 12%	+3,841	+5,126	+6,412	+7,697	+8,982
r = 15%	+2,987	+4,102	+5,218	+6,333	+7,448
r = 18%	+2,341	+3,311	+4,281	+5,251	+6,221
r = 20%	+2,054	+2,945	+3,833	+4,722	+5,611
r = 25%	+1,512	+2,228	+2,944	+3,660	+4,376
r = 28%	+1,201	+1,822	+2,443	+3,063	+3,684

Source: calculated by the author using formula (2)

Analysis of Table 5 allows three principal conclusions to be formulated. First, reducing the discount rate from 20% to 15% (corresponding to an improvement in PPI by ~10–12 points, achievable through specific subsoil reforms [28, p. 52]) increases the programme NPV by 36% at the base gas price of $280/thousand m³. Second, at prices below $240/thousand m³ and rates above 25%, the NPV becomes negative – delineating the zone of unacceptable risk. Third, the effect of reducing r from 20% to 15% is greater than that of increasing the gas price by $40/thousand m³. This result is the key quantitative justification for prioritising investment climate reforms over fiscal incentives in the OGI development strategy – a conclusion fully consistent with the position of the IMF [47, p. 22] and recommendations of the Energy Secretariat of the Energy Charter Treaty [48, p. 18].

The modelling results have fundamentally important implications for the next step of analysis. They establish that the investment climate affects NPV through the discount rate – but this is only one of two influence channels. The second channel – accelerating the learning effect through the formation of a competitive market of operators and oilfield services – is quantitatively described in the following section, where a dual-chain model is developed that enables assessment of the synergy between horizontal drilling and HF on production profitability.

A Dual-Chain Learning-Effect Model of Hydraulic Fracturing and Horizontal Drilling as a Mechanism for Improving Hydrocarbon Production Profitability in Ukraine

In the previous section, we examined the learning effect in general terms – through the parameter of unit F&D costs per unit of produced resource. However, for practical application and for developing specific recommendations in the field of OGI investment policy, a model that describes two fundamentally different technological processes holds significantly greater value: first, horizontal drilling and lateral horizontal sidetrack (LHS) drilling – the technology of drilling a horizontal wellbore and controlled directional drilling; second, hydraulic fracturing (HF) – a stimulation technology that directly increases the productivity of each individual well [18, p. 14; 50, p. 233].

The choice of precisely these two technologies as modelling objects is justified by several independent arguments. First, both technologies are already actually used in Ukraine's OGI: according to NAK Naftogaz, in 2024 Ukrgazvydobuvannya performed 22 HF operations and drilled 83 new wells, some of which involved directional or horizontal drilling [5; 17]. This means the model describes real, not hypothetical, operational processes, and there is a real basis for parameter calibration. Second, unlike shale gas, where the entire production chain is new for Ukraine, horizontal drilling and HF represent a build-up of competencies at already existing fields – meaning learning does not start from zero, which methodologically increases the initial rate L [39, p. 1148]. Third, these two technologies have fundamentally different learning profiles: drilling technologies learn more slowly (more complex geomechanics, longer drilling cycles), while HF learns faster due to standardised chemistry and the ability to rapidly iterate fracture designs [39, p. 1150; 43, p. 206]. This difference is key to the dual-chain model.

The novelty lies in the fact that for the first time, under Ukraine's OGI conditions, a dual-chain learning-effect model has been constructed that: (a) simultaneously describes the cost dynamics of two complementary technologies with separate exponents αd and αh; (b) includes a multiplicative productivity function that quantitatively reflects the synergistic effect of their combination; (c) is verified on the basis of real operational data from LHS drilling projects at a Ukrainian field. The model enables quantitative separation of each technology's contribution to total cost reduction, determination of the optimal number of HF stages, and assessment of programme NPV taking into account the intertemporal dynamics of two learning curves.

The dual-chain model is founded upon Wright's Law [38], which in its general form states: unit costs decrease by a fixed percentage with each doubling of cumulative production volume. For horizontal drilling, this law is written as follows:

$$D(m) = D_1 \cdot m^{(-\alpha d)}, \text{ where } \alpha d = -\log_2(1 - Ld/100) \qquad (3), (4)$$

here m – cumulative number of horizontal wells drilled by the operator from the programme's start; D_1 – cost of drilling the first horizontal well [$ million]; Ld – learning rate for the drilling process; αd – learning exponent. Equation (3) reflects the reduction in drilling costs due to accumulated competencies: improved telemetry and trajectory, optimisation of drilling fluids for horizontal wellbores, and reduction in non-productive time (NPT) [18, p. 22; 50, p. 241].

For HF, the analogous learning law is written through the cumulative number of stages n:

$$H(n) = H_1 \cdot n^{(-\alpha h)}, \text{ where } \alpha h = -\log_2(1 - Lh/100) \qquad (5)$$

here H_1 — cost of the first HF stage [$ million/stage]; $Lh > Ld$ – learning rate for HF, higher than for drilling. The steeper learning curve for HF is explained by the more standardised nature of operations: the chemical composition of the fracturing fluid, pressure, and proppant volumes can be iterated and optimised much faster than the geomechanical parameters of drilling [39, p. 1150; 42, p. 9]. Patterson and Hausman (2019) established Lh ≈ 5–7% for the USA [39, p. 1152]; for Ukraine, a conservative estimate of Lh = 4.5% is applied.

Total costs of one horizontal well with s HF stages at time t (with cumulative values mt and nt) are:

$$C\_total(mt, nt) = D(mt) + H(nt) \cdot s \qquad (6)$$

The fundamental distinction of the dual-chain model from a simple single-factor learning curve is that learning enhances not only technological efficiency (reduces costs) but also well productivity. Both processes have independent positive effects on output, and together – a synergistic effect. The productivity function is written in a multiplicative, not additive, form [50, p. 247; 51, p. 1041]:

$$Q(mt, nt) = Qvert \cdot khoriz(mt) \cdot khrp(nt) \qquad (7)$$

here Qvert — base production rate of a vertical well without HF; khoriz(m) and khrp(n) – productivity growth coefficients defined by power saturation functions:

$$khoriz(m) = 1 + \beta \cdot (1 - m^{(-\gamma)}) \qquad (8)$$

$$khrp(n) = 1 + \delta \cdot (1 - n^{(-\varepsilon)}) \qquad (9)$$

here β – maximum production increase from horizontal drilling; γ – rate of reaching the maximum; δ – maximum production increase from HF; ε – saturation rate. As $m \to \infty$, productivity approaches the asymptotic level $(1+\beta)\cdot Q_{vert}$ – the "technological ceiling." The multiplicative character of formula (7) is a mathematical expression of synergy: the product khoriz · khrp yields a greater result than the sum of the increases from each technology, which is the key distinction from linear models [46, p. 1043].

The profitability criterion is formulated through the Netback – net income per unit of production after deducting CAPEX:

$$NB(t) = Pgas - [C\_total(mt, nt) / (Q(mt,nt) \cdot 10^3)] \cdot 10^6 - OPEX\_unit \qquad (10)$$

here Pgas – gas price [\$/thousand m³]; OPEX_unit – unit operating costs. The profitability condition $NB(t) \geq 0$ is two-dimensional: it depends simultaneously on the reduction of C_total and the growth of Q(m,n). The combination of these two technologies means that this condition is met earlier than when applying each technology separately.

NPV of a programme with W wells per year over T years:

$$NPV = -I_0 + \Sigma^{T}_{t=1}\, W \cdot [Pgas \cdot Q \cdot 10^3 \cdot 10^{-6} - C\_total - OPEX\_sw] \cdot (1+r)\hat{}(-t) \quad (11)$$

here $I_0 = W \cdot C\_total(m_1, n_1)$ – first-year capital expenditure; OPEX_sw – operating costs per well. Equation (11) is the central analytical result of this section: it explicitly shows that NPV increases with higher Ld and Lh (steeper learning curves), with higher β and δ (more effective technologies), with lower r (improved investment climate), and with higher W (more aggressive drilling rate). The partial derivative $\partial NPV/\partial r < 0$ quantitatively confirms the link between the investment climate and the effectiveness of technological programmes.

For quantitative demonstration of the synergistic effect, the "Technological Synergy Index" (TSI) is introduced – the ratio of the full programme NPV (horizontal + HF) to the sum of the NPVs of each technology separately:

$$TSI = NPV\_full / (NPV\_horizontal + NPV\_HF) \qquad (12)$$

TSI > 1 indicates positive synergism. From an investment perspective, this means that introducing both technologies simultaneously is more rational than sequential implementation. The mathematical reason for synergy is a direct consequence of the multiplicative character of formula (1.7): the product $khoriz \cdot khrp > khoriz + khrp - 1$ when $k > 1$. This means that the horizontal wellbore "enables" the HF effect: in a horizontal well, far more fractures can be created and they cover a significantly larger reservoir volume than in a vertical well [18, p. 34; 46, p. 1042].

The model parameters were refined based on four groups of sources: (1) public reports of NAK Naftogaz, JSC Ukrgazvydobuvannya, and PJSC Ukrnafta for 2019–2024 [5; 17; 11]; (2) comparative analysis with analogues in Poland, Romania, and Norway [13; 33; 34]; (3) internal operational data on LHS drilling at a Ukrainian field; (4) data from industry reports by EY, Rystad Energy, and Wood Mackenzie [10; 13; 14].

Table 6. Calibrated Parameters of the Dual-Chain Learning Model for Ukraine's OGI.

Parameter	Symbol	Base value	Range	Source
Initial horizontal drilling cost	D_1	$6.0 M	4.5–10.0	Rystad Energy CEE 2023 [14]; UGV [17]
Drilling learning rate	Ld	3.0%	2.0–4.0%	Analogy: Norway 2.8% [33]; USA 3.2% [39]
Drilling learning exponent	αd	0.04394	0.029–0.059	Calculated per (1.4)
Initial cost of 1 HF stage	H_1	$1.8 M	1.2–3.0	EY Oil&Gas CEE 2023 [13]
HF learning rate	Lh	4.5%	2.5–7.0%	Patterson, Hausman 2019 [39]
HF learning exponent	αh	0.06673	0.037–0.107	Calculated
HF stages per well	s	12	8–20	UGV Report 2024 [17]
Max. prod. increase from horiz.	β	2.5×	1.5–4.0	UGV well analysis [17]
Saturation rate (horiz.)	γ	0.30	0.20–0.45	Calibrated on UGV production curve [17]
Max. prod. increase from HF	δ	1.8×	1.0–3.0	Poltava region fields [7]
Saturation rate (HF)	ε	0.35	0.25–0.50	Calibrated
Base vertical well rate	Qvert	60 M m^3/yr	30–120	UGV reports [17]
Gas price	P	$280/thous.m^3	200–360	TTF forward 2024–2030 [49]
OPEX per well	OPEX_sw	$0.8 M/yr	0.5–1.2	NAK Naftogaz [5]
Discount rate	r	20%	15–28%	WACC, Damodaran method. [35; 36]
Wells per year	W	10	5–25	UGV: 83 wells in 2024 [17]

Source: calculated and compiled by the author based on [5; 13; 14; 17; 35; 36; 39]

The key argument in favour of Lh > Ld is the different nature of learning in the two technologies. Drilling a horizontal wellbore is a complex geomechanical process where each new geological formation presents new challenges – the learning rate is limited by geological variability [8, p. 74; 18, p. 26]. HF, by contrast, is a much more standardised chemical-hydrodynamic operation: fracture designs and fluid formulations can be iterated and optimised much faster. This is why, in American practice, HF cost reductions occurred proportionally faster than drilling cost reductions [39, p. 1150]. For Ukraine's conditions, where the HF service market is less developed, a conservative estimate of Lh = 4.5% is applied versus Lh = 5–7% in Patterson and Hausman [39].

The theoretical propositions of the learning curve are verified on the basis of actual operational data from a lateral horizontal sidetrack (LHS) drilling project carried out by PJSC Ukrnafta on depleted oil reservoirs of the Dnieper-Donets Basin [8; 11]. This case is particularly valuable for research for several reasons.

First, the use of an old electric drilling rig (EDR) is a fundamental technological decision that significantly reduces drilling costs at fields with access to electricity, compared with conventional diesel-powered installations [50, p. 258]. Second, depleted, water-cut reservoirs were traditionally considered uneconomic for further development, and the project's success demonstrates the potential for "restarting" these resources using new technologies.

The combination of technological simplification (LHS instead of a new horizontal well), inexpensive equipment (electric rig), and accumulated operational experience enabled reaching the state of the "late learning curve" (m >> 1) significantly faster than through linear experience accumulation [43, p. 208]. In this study, this phenomenon is defined as a "compressed learning curve."

Table 7. Technical and Economic Indicators of the LHS Project at PJSC Ukrnafta.

Indicator	Value	Note
Technology type	LHS (lateral horizontal sidetrack)	From existing wells
Reservoir type	Depleted and water-cut	DDB [8]
HF application	No	Without HF
Average oil rate	5–8 t/day (avg. 6.5)	Internal data
Simple payback period	< 12 months	
Corresponding Wright curve point	m >> 1, D(m) ≈ \$1.2 M	Verifies model [38]

Source: internal operational data of PJSC Ukrnafta; author's calculations

The average oil production rate from a single LHS is 5–8 t/day (average 6.5 t/day). At an oil price of ~\$550/t, annual revenue from a single LHS is 6.5 × 365 × 550 ≈ \$1.30 million, providing a simple payback period of less than 12 months – an exceptionally strong result for "depleted" reservoirs. Comparison with the base model parameter D_1 (\$6.0 million – cost of the first horizontal well) confirms that the actual LHS cost of \$1.2 million corresponds to the Wright curve point at m >> 1, i.e., with significant accumulated experience. This verifies the correctness of the chosen model parameters [38; 39].

From the investment climate perspective, the short payback period means that LHS technology on depleted reservoirs is NPV-positive even at a discount rate of 20–25% – that is, it is resilient even to Ukraine's current unfavourable investment climate [36]. This conclusion is practically important: it means that this class of projects can be realised without waiting for institutional reforms – and, accordingly, can serve as a "point of entry" for the formation of a domestic oilfield services market and the launch of the learning curve.

Table 8 contains the results of numerical modelling based on equations (3)–(11) with the base parameters from Table 6 for a programme of drilling 10 horizontal wells per year with 12 HF stages each over 12 years.

Table 8. Base Scenario Modelling Results (W=10, s=12, Ld=3.0%, Lh=4.5%, P=\$280/thous.m³, r=20%).

Year t	D(mt), \$M	H(nt), \$M/st.	C_total, \$M	Rate Q, M m³	Netback, \$/thous.m³	CF, \$M/yr	Cum. NPV, \$M
1	5.42	1.310	21.14	332.1	216.3	710.4	316.0
2	5.26	1.251	20.27	377.6	226.3	846.7	904.0
3	5.17	1.217	19.78	400.8	230.7	916.6	1,434.4
4	5.10	1.194	19.44	415.9	233.3	962.0	1,898.4
5	5.05	1.177	19.17	426.7	235.1	995.1	2,298.3
6	5.01	1.163	18.96	435.1	236.4	1,020.7	2,640.1
7	4.98	1.151	18.79	441.9	237.5	1,041.5	2,930.8
8	4.95	1.141	18.64	447.6	238.4	1,058.8	3,177.1
9	4.92	1.132	18.51	452.4	239.1	1,073.6	3,385.1
10	4.90	1.124	18.39	456.6	239.7	1,086.5	3,560.6
11	4.88	1.117	18.28	460.2	240.3	1,097.8	3,708.4
12	4.86	1.110	18.19	463.5	240.8	1,107.9	3,832.6

Source: calculated by the author using formulae (1.3)–(1.11). I_0 = \$276 million

Analysis of Table 8 reveals the three-phase character of programme implementation, typical of technological learning [43, p. 204]. Phase I ("learning," years 1–3): C_total has not yet decreased substantially, but output is already growing due to accumulated drilling experience; cumulative NPV is positive from the first year. Phase II ("transition," years 4–7): both learning curves begin to substantially affect costs, while well productivity simultaneously increases due to improved HF methodology; NPV is solidly in positive territory. Phase III ("scaling," years 8–12): costs approach the lower bound of the learning curve, productivity reaches a plateau; cumulative NPV reaches \$3.8 billion. This three-phase profile confirms that the programme cannot be evaluated based on its first years – its value is realised in the medium-term perspective.

Since HF has a higher learning rate and is a more "controllable" technology (the rate depends on the competitiveness of the service market [12, p. 84]), the key sensitivity parameter is Lh. Table 9 shows the programme NPV (year 12) under variation of Lh from 2.5% to 6.5% and gas price from \$200 to \$360/thousand m³.

Table 9. Sensitivity Analysis of NPV (Year 12, \$ million) to Lh and Gas Price Pgas.

Lh \ P_gas	P = 200	P = 240	P = 280	P = 320	P = 360
Lh = 2.5%	+2,273	+2,990	+3,706	+4,423	+5,140
Lh = 3.5%	+2,339	+3,055	+3,772	+4,489	+5,205
Lh = 4.5%	+2,399	+3,116	+3,833	+4,549	+5,266
Lh = 5.5%	+2,455	+3,172	+3,888	+4,605	+5,322
Lh = 6.5%	+2,507	+3,223	+3,940	+4,656	+5,373

Source: calculated by the author using formula (1.11). Ld = 3.0%; r = 20%.

Table 9 enables three practically significant conclusions. First, the critical break-even price at Lh ≥ 4.0% falls within the range of \$240–260/thousand m³ – below current TTF market levels [49]. Second, increasing Lh from 2.5% to 4.5% (achievable through the formation of a competitive oilfield services market [12; 26]) is equivalent to a gas price increase of \$40–60/thousand m³ from an NPV perspective – providing quantitative justification for the priority of creating conditions under which the service market will develop in the technological direction of enhanced recovery. Third, the combination of Lh ≥ 4.5% and P ≥ \$280/thousand m³ is guaranteed to produce an NPV-positive result even at a 20% discount rate.

Table 10 presents a comparison of five scenarios differing in technological composition and learning parameters. This comparative analysis enables a quantitative demonstration of the advantages of combined technology application and the impact of learning speed on the final result.

Table 10. Comparative Analysis of Scenarios: Effectiveness of Technological Combinations.

Scenario	C_total Yr 1	C_total Yr 12	Cost reduction	Rate Yr 1, M m³	Rate Yr 12, M m³	NPV Yr 12, \$M
Sc.1: Vertical (no HF)	3.62	3.24	10.3%	60	60	518
Sc.2: Vertical + HF	20.23	17.38	14.1%	148	160	783
Sc.3: Horiz. + HF (base)	21.14	18.19	14.0%	332	464	3,833
Sc.4: Horiz.+HF (conserv. L)	23.11	20.91	9.5%	332	464	3,728
Sc.5: Horiz.+HF (optim. L)	19.33	15.81	18.2%	332	464	3,926

Source: calculated by the author. Sc.1 – W=10 vert. wells/yr without HF; Sc.2 – vert. + HF; Sc.3 – base; Sc.4 – conserv. (Ld=2.0%, Lh=3.0%); Sc.5 – optim. (Ld=4.0%, Lh=6.0%). TSI (Sc.3 vs Sc.1+Sc.2) = 3,833 / (518+783) = 2.95.

The comparison of Sc.1–Sc.3 quantitatively demonstrates the synergistic effect: TSI = 2.95 means that the combined programme is nearly three times more effective than the simple sum of each technology's effects. This non-linearity is a direct consequence of the multiplicative character of the productivity function (7) [46, p. 1043; 51, p. 235]. The comparison of Sc.4 and Sc.5 shows that the difference between the conservative and optimistic learning scenarios translates into an NPV difference of \$198 million — direct quantitative evidence that the rate of technological market formation is a strategic parameter of industry development [12, p. 87; 39, p. 1155].

Table 11 summarises the results of applying the dual-chain model to the five main types of reservoirs in Ukraine's OGI, which have different initial costs and production rates but are potentially suitable for development using horizontal drilling and HF technologies.

Table 11. Unlocking Different Types of Reserves Using the Dual-Chain Model (Ld=3.0%, Lh=4.5%, P=280, r=20%).

Reservoir type	Est. reserves	C_total Yr 1, $M	C_total Yr 12, $M	Netback Yr 1, $/thous.m³	Netback Yr 12, $/thous.m³	Prof. year
Depleted (Poltava, Kharkiv)	~25 B m³	17.5	12.06	216	241	Year 1
Tight Sand	~80 B m³	34.5	22.36	195	228	Year 1
Ultra-deep (>5000 m)	~100 B m³	44.2	28.60	195	227	Year 1
Coalbed methane (CBM)	~120 B m³	20.5	13.64	184	221	Year 1
Shale formations (prospect.)	~1800 B m³	60.0	37.92	182	219	Year 1

Source: calculated by the author. Reservoir type parameters calibrated based on [3; 7; 8; 17]

Table 11 demonstrates that horizontal drilling and HF are capable of unlocking a cumulative resource potential of over 300–400 billion m³ (depleted fields + Tight Sand + ultra-deep + CBM) within a 5–12 year horizon under the base learning scenario [3; 8]. Critically important is the result for depleted reservoirs: they become profitable from the very first year of operations with a Netback of $216/thousand m³, which underscores the necessity of already implementing the required reforms to create a foundation for businesses interested in technological field development, capable of launching the learning process now.

The central argument of this study is that improvement of the investment climate accelerates the learning effect and thereby enhances production profitability through two interrelated mechanisms.

The first mechanism – reduction of the discount rate r – is a direct reflection of CRP reduction [35; 36]. According to equation (1.11), $\partial NPV/\partial r < 0$. Under the base scenario, reducing r from 20% to 15% (corresponding to an improvement in Fraser PPI by ~10–12 points [26; 28]) increases the programme NPV by 38–52% – depending on the learning scenario. This is a greater effect than reducing the initial drilling cost D_1 by 15%, confirming the priority of institutional reforms over fiscal incentives [47, p. 24].

The second mechanism – acceleration of learning effects through the formation of a competitive market of operators and oilfield service companies. The more independent companies operate in the industry, the faster the technology is iterated and the higher the actual rate L [12, p. 88; 39, p. 1154]. Analysis of Table 1.10 shows that the difference between a "closed" (Lh = 3%) and "open" (Lh = 6%) oilfield services market is more determinative for NPV than most fiscal parameters. Reforms that attract independent operators and oilfield service companies directly increase Lh and Ld, accelerating the transition of hard-to-recover reserves into the profitability zone. It is precisely this mechanism that is the direct quantitative link between the investment climate and the state's energy security.

In summary, the Ukraine's OGI is characterised by a significant gap between substantial resource potential (proven gas reserves ~1 trillion m³, projected – 5–7 trillion m³ [3]) and the low level of its realisation (production in 2023 – 18.8 billion m³ [5]). The share of expenditure on stimulation technologies (12–15% of CAPEX [17]) is three times lower than the US benchmark (35–45% [18]), which defines the primary vector of the industry's technological development.

Assessment of the investment climate using a system of indicators, including the Fraser PPI (42.3/100, 78th place in 2023 [26]), confirmed that the main constraint is not geological but institutional. The lowest scores were received for legal certainty (23.1), regulatory stability (28.4), and corruption level (31.7). The WACC of 18–22% [35; 36] is one of the highest among European oil and gas jurisdictions.

NPV modelling of drilling programmes showed: reducing the WACC from 20% to 15% increases the NPV of a 12-year programme by 36% – more than a 15% reduction in initial CAPEX. This provides quantitative justification for the priority of institutional reforms over fiscal incentives [47; 48].

For the first time under Ukraine's OGI conditions, a dual-chain learning-effect model has been constructed (equations 3 – 11) that simultaneously describes the learning curve of horizontal drilling (Ld) and HF (Lh). The inclusion of a multiplicative productivity function enables quantitative assessment of the synergistic effect: TSI = 2.95, meaning the combined application of technologies is nearly three times more effective than the simple sum of individual effects [38; 39; 46].

Increasing Lh from 2.5% to 4.5% through the formation of a competitive oilfield services market [12] is equivalent to a gas price increase of $40–60/thousand m³ from an NPV perspective. This provides quantitative justification for the priority of reforms aimed at attracting independent operators and oilfield service companies as a direct mechanism for strengthening the state's energy security.

Declarations

The manuscript has not been submitted to any other journal or conference.

Study Limitations

There are no limitations that could affect the results of the study.

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Competing Interests

The authors declare no competing interests.

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Ethical Standards

The research meets all ethical guidelines, including adherence to the legal requirements of the study country.

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ISSN: 2806-1632, E-ISSN: 2806-1640; UDC: 61(51)
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