

THE ADVANCED DIPLOMA IN INTERNATIONAL TAXATION

June 2026

MODULE 3.04 – ENERGY RESOURCES OPTION

SUGGESTED SOLUTIONS

PART AQuestion 1Step 1: Calculate Annual Revenue

Revenue = Production × Price

<u>Year</u>	<u>Production</u>	<u>Price</u>	<u>Revenue (£)</u>
0	0	65	0
1	400,000	80	32,000,000
2	500,000	85	42,500,000
3	600,000	80	48,000,000
4	700,000	60	42,000,000
5	1,000,000	70	70,000,000

Step 2: Calculate Profit Before Sharing

Profit before sharing = Revenue – Operational Costs

<u>Year</u>	<u>Revenue</u>	<u>Operational Costs</u>	<u>Profit (£)</u>
0	0	6,000,000	(6,000,000)
1	32,000,000	5,000,000	27,000,000
2	42,500,000	3,000,000	39,500,000
3	48,000,000	4,000,000	44,000,000
4	42,000,000	5,000,000	37,000,000
5	70,000,000	8,000,000	62,000,000

Step 2: Deduct Year 0 recoverable cost (£6M) from Year 1

Year 1 profit after recovery = 27,000,000 – 6,000,000 = 21,000,000

Updated profits:

<u>Year</u>	<u>Profit after recovery (£)</u>
1	21,000,000
2	39,500,000
3	44,000,000
4	37,000,000
5	62,000,000

Step 3: Split Profit Oil (50% Country Nobala / 50% Lucky Oil & Gas)

<u>Year</u>	<u>Total Profit (£)</u>	<u>Government Share (£)</u>	<u>Company Share (£)</u>
1	21,000,000	10,500,000	10,500,000
2	39,500,000	19,750,000	19,750,000
3	44,000,000	22,000,000	22,000,000
4	37,000,000	18,500,000	18,500,000
5	62,000,000	31,000,000	31,000,000

Step 4: Apply Taxes on Company Profit (Oil Tax Deductible)

Oil tax 40% deductible – reduces taxable profit for corporation tax

Corporation tax 20% applied after deducting oil tax

Calculation formula:

- Oil tax = 40% of company share - Profit after oil tax = Company share - Oil tax - Corporation tax = 20% × Profit after oil tax - Net Profit = Company share - Oil tax - Corporation tax

Year	Company Share (£)	Oil Tax (£) 40%	Profit after Oil Tax (£)	Corp Tax (£) 20%	Net Profit (£)
1	10,500,000	4,200,000	6,300,000	1,260,000	5,040,000
2	19,750,000	7,900,000	11,850,000	2,370,000	9,480,000
3	22,000,000	8,800,000	13,200,000	2,640,000	10,560,000
4	18,500,000	7,400,000	11,100,000	2,220,000	8,880,000
5	31,000,000	12,400,000	18,600,000	3,720,000	14,880,000

Deduct Bonus Payments (Year 0 = £2M, Year 4 = £1M) Total Bonus = £3,000,000

Net Profit for Lucky Oil & Gas = (5,040,000 + 9,480,000 + 10,560,000 + 8,880,000 + 14,880,000) – 3,000,000 = £45,840,000

Step 5: Total Revenue for Country Nobala

Revenue = Government Share of Profit Oil + Taxes collected + bonus

Government Share of Profit Oil = 10,500,000 + 19,750,000 + 22,000,000 + 18,500,000 + 31,000,000 = 101,750,000

Taxes collected (Oil Tax + Corporation Tax) = 4,200,000 + 1,260,000 + 7,900,000 + 2,370,000 + 8,800,000 + 2,640,000 + 7,400,000 + 2,220,000 + 12,400,000 + 3,720,000 = 52,810,000

Total Revenue for Nobala = Share of Profit 101,750,000 + Taxes 52,810,000 + bonuses 2,000,000 + 1,000,000 = £157,560,000

Limited control over operations: Under a PSA, the government often has less direct control over exploration and production decisions, as the international oil company (IOC) or contractor typically manages operations. This can reduce the government's ability to influence project priorities, timelines, and local participation.

Revenue volatility: PSAs usually involve cost recovery by the contractor before profit sharing. This means government revenues are highly dependent on production levels and fluctuating oil prices, which can create unpredictability in fiscal planning and budgeting.

Complexity and administrative burden: PSAs are often highly technical and legally complex, requiring extensive monitoring and auditing to ensure compliance. Governments may incur significant costs in terms of regulatory oversight and skilled personnel to manage these agreements effectively.

Question 2

Part 1

Tax treaties are fundamental instruments designed to prevent double taxation and provide overriding investment certainty for multinational enterprises. In international tax law, a validly ratified Double Tax Agreement (DTA) generally supersedes or "overrides" more stringent or conflicting domestic tax legislation under the principle of *pacta sunt servanda*.

Here, the primary conflict lies between Azuria's domestic law, which aggressively seeks to tax offshore resource activities after a mere 30 days, and the DTA's more generous 12-month threshold. DeepSea Global can successfully rely on the DTA's 12-month rule to claim no Permanent Establishment (PE) exists up to that point, assuming the operation of the Mobile Offshore Drilling Unit (MODU) is legally characterized as a "building site or construction or installation project" under the specific terms of the treaty.

This treaty precedence is a cornerstone for international oil and gas investment certainty. It guarantees operators that their tax exposure will not be arbitrarily triggered by unilateral domestic legislative changes—like Azuria's 30-day rule—thereby protecting the economic models and expected returns of highly capital-intensive offshore projects.

Part 2

"Contract splitting" is a traditional tax planning strategy where multinational enterprises artificially fragment the timeline of a project among various related entities to ensure that no single entity breaches the time threshold required to create a PE. Historically, this allowed oil and gas companies to avoid host state taxation entirely.

However, the international tax landscape has shifted significantly with the introduction of BEPS Action 7, which many jurisdictions have now implemented via the Multilateral Instrument (MLI). These anti-fragmentation rules explicitly mandate the aggregation of time spent by closely related enterprises performing connected activities at the same site.

The Azurian Revenue Authority (ARA) has a strong legal basis to aggregate the 5 months spent by Sub-A (seismic surveys) and the 8 months spent by Sub-B (drilling). Because these related party structures are working on fundamentally connected phases of the exact same exploration project, the total cumulative time equals 13 months, directly exceeding the 12-month treaty threshold. Furthermore, neither seismic surveys nor drilling activities can be shielded under the treaty's "preparatory or auxiliary" exemptions, as both are core, essential income-generating activities in the context of offshore resource extraction. Consequently, this related party structuring fails to prevent the creation of a PE.

Part 3

The treatment of business profits differs significantly between the two major international tax treaty models. Under Article 7 of the OECD Model Convention, the host state is strictly limited to taxing only those profits that are directly "attributable to" the Permanent Establishment itself.

In stark contrast, the UN Model Convention incorporates a "force of attraction" principle, which fundamentally broadens the host state's taxing rights. This specific UN definition allows the host country to tax not only the profits of the PE but also other business profits generated by the head office in that country, provided they arise from sales of goods or business activities of the same or similar kind as those effected through the PE.

Since the scenario explicitly states that the DTA is OECD-based, it naturally lacks this UN-style force of attraction clause. Therefore, relying on standard OECD definitions, the ARA is not legally justified in taxing the entirely unrelated management and consultancy fees earned by DeepSea Global in the capital. Those profits remain protected as general business profits under Article 7 and are taxable exclusively in DeepSea Global's state of residence.

Part 4

The establishment of a PE triggers a fundamental shift in the method of taxation and the associated compliance burden for DeepSea Global. Without a PE, a foreign entity typically faces only a Withholding Tax (WHT) strictly levied on gross service fees. While WHT is a final tax and administratively simple, it does not allow for the deduction of any operational expenses.

Once a PE is successfully established by the ARA, DeepSea essentially transitions into the Corporate Income Tax (CIT) regime. Under CIT, tax is levied on net profits, which can be advantageous for capital-intensive offshore projects as it permits the deduction of legitimate business expenses, asset depreciation, and potentially overhead allocations.

However, this shift introduces severe risk in the form of increased administrative and accounting costs. DeepSea must formally register as a local taxpayer in Azuria, maintain separate and localized PE accounting records, and file annual tax returns.

Furthermore, determining the exact profits attributable to the localized PE requires complex transfer pricing analyses to ensure arm's-length dealings are maintained between the head office and the Azurian branch, exposing the company to ongoing compliance scrutiny and potential future tax audits.

PART B

Question 3

Part 1

Contracts with governments may provide for state equity, which refers to the government's ownership share in an oil and gas development project. This right to an interest in the project is often combined with other fiscal and taxation methods.

Forms of State Equity:

- Full working interest – Paid-up equity on commercial terms, placing the government on equal footing with private investors.
- Concessional paid-up equity – Government acquires its share at a below-market price, sometimes with the option to join the project after a commercial discovery.
- Carried interest – The government's equity share is financed by the oil and gas company and repaid from production proceeds, including an interest charge.
- Tax swapped for equity – The government's equity share is offset against a reduced tax liability.
- Equity in exchange for non-cash contribution – For example, the government provides infrastructure such as pipelines, roads, or harbours in return for equity.
- "Free" equity – Appears costless, but the non-cash provision usually results in some form of offsetting reduction in other taxes.

Part 2

State equity can take several forms and plays a significant role in the financial and strategic aspects of oil and gas projects.

The government may have an option to acquire an interest if the project is successful, for example after a commercial discovery has been made.

The government may have a carried interest, in which the government's share of exploration and development expenses is paid by the oil and gas company. The government may pay for its equity share and share of expenses from the proceeds of oil or gas production if the project proceeds to the production stage. The oil and gas company carries the risk of not being reimbursed for the expenses if the project does not result in significant production.

State equity may be acquired in return for a reduced tax liability on the oil and gas company.

State equity may also be acquired for a non-cash contribution, such as government provision of project infrastructure, such as harbour facilities, roads and pipelines.

State equity is quite significant for the financial model of an oil and gas project. The structure of state equity is not a tax, sharing of profit oil, or a royalty. However, the state may effectively obtain an additional large portion of profits, for example by exercising an option to acquire a 25% share of a project.

This is often an issue with new investments and for mergers and acquisitions, where the state equity, or the option for the government to acquire state equity, will significantly affect the oil and gas company's net return from the investments.

Motivations for State Equity

State equity participation is primarily motivated by a desire to share in a project's potential upside. However, it can also serve non-economic objectives, including:

- Nationalistic sentiment and resource sovereignty
- Facilitating technology transfer and knowledge development
- Providing direct control over project development

Question 4

The use of cross-border leasing and sale-leaseback arrangements for high-value offshore assets like MODUs and FPSOs introduces a complex interplay of domestic tax laws, international tax treaties, and anti-avoidance measures.

A tax issue is the classification of the lease. Tax authorities increasingly apply a "substance over form" approach to determine whether an arrangement is an operating lease or a finance lease, irrespective of its legal title. Operating leases are traditionally treated as rental agreements, where the lessee deducts the full lease payments as operating expenses (OPEX). In contrast, if the economic risk and reward have transferred to the lessee, authorities classify the transaction as a finance lease (a debt-financed purchase), meaning tax deductions are strictly limited to the interest component of the payments and capital allowances on the asset.

Mismatches between domestic tax treatment and accounting standards (such as IFRS 16, which brings most leases onto the balance sheet) require careful deferred tax accounting and adjustment.

When lease payments flow across borders to a foreign lessor, their characterisation under double tax agreements is critical. Under the OECD Model Tax Convention, equipment lease payments generally fall under Article 7 (Business Profits) and are not subject to Withholding Tax (WHT) in the source state unless a Permanent Establishment (PE) exists. However, many resource-rich Host States follow the UN Model Tax Convention, which explicitly includes payments for the use of "industrial, commercial, or scientific equipment" within the definition of Royalties (Article 12), exposing gross lease payments to potentially high WHT rates.

In a finance lease, the payment must be bifurcated: the interest portion may be subject to Article 11 (Interest) WHT, while the principal repayment is generally not subject to withholding. Energy groups often strategize by routing leases through jurisdictions with favourable tax treaty networks, though this is heavily scrutinized.

Leasing high-value assets into a Host State's territorial waters or Exclusive Economic Zone (EEZ) carries a high risk of creating a PE. While a "bareboat charter" (leasing the vessel without a crew) might avoid a PE in some jurisdictions as the lessor has no active presence, providing a "time charter" (vessel plus crew for operations) or an FPSO anchored for years will almost certainly trigger a PE under fixed-place or offshore-specific treaty clauses. If a PE is triggered, the lessor becomes subject to local Corporate Income Tax on net profits attributable to the lease.

Energy companies frequently use operating leases to optimize their balance sheets and avoid triggering domestic thin capitalisation rules or corporate interest restrictions (CIR) modelled on BEPS Action 4. Because operating lease payments are OPEX rather than interest, they can bypass EBITDA-based interest deductibility limits. However, if a lease lacks commercial substance or is deemed to be disguised financing, authorities may recharacterize the rental payments as interest, applying the CIR limits and denying deductions.

Sale-leaseback arrangements allow an operator to sell an owned, partially depreciated asset (like an FPSO) to a third-party or group financing company and lease it back. While this unlocks commercial liquidity, it triggers a disposal for capital gains tax (CGT) or a balancing charge (recapture of capital allowances) on the sale. Strategically, if the asset is still of high market value, the immediate tax cost of the sale must be weighed against the benefit of claiming full tax deductions on the new, higher future lease payments.

Leasing operations are significantly impacted by indirect taxes. The temporary importation of a MODU or FPSO can trigger massive customs duties and import VAT based on the hull's value. Companies must heavily utilize temporary admission regimes or specific oil and gas exemptions to suspend these liabilities.

Under BEPS Action 6 and the Principal Purpose Test (PPT), multinational groups establishing central leasing hubs must demonstrate genuine economic substance. A purely paper-based leasing entity in a low-tax jurisdiction will be denied treaty benefits. Taxpayers must ensure the leasing entity has adequate local staffing, capital risk, and management control over the assets.

PART C

Question 5

Ring fencing is a mechanism that limits the deduction of costs for tax purposes across different activities or projects undertaken by the same oil and gas company. It requires contractors or concessionaires to restrict cost recovery and deductions associated with a particular license—or sometimes a specific field—to that license or field only. In practice, this means that all costs related to a particular block or license must be recovered solely from revenues generated within that block.

The scope of ring fencing can vary. In some countries, oil and gas activities are ring-fenced from other activities performed by the same company within the country, such as downstream operations. In other jurisdictions, individual projects are ring-fenced from other projects held by the same company, meaning that the ring fence can apply to individual licenses or on a field-by-field basis.

Under such arrangements, exploration expenses in a non-producing block cannot be deducted against income from another block for tax purposes. Similarly, under Production Sharing Contracts (PSCs), ring fencing ensures that costs incurred in one ring-fenced block cannot be recovered from revenues generated in another block outside that ring fence.

Impact on Oil and Gas Companies

Ring fencing may increase tax liabilities for individual projects because profits must be calculated separately for each ring-fenced area.

Companies cannot consolidate profits or losses across different projects for tax purposes.

If all projects are profitable, the effect is mainly a timing issue—costs are eventually recovered, but later than without ring fencing.

Prevents companies from offsetting costs across projects, which can favour existing players over new entrants who may only hold a single license.

Adds administrative complexity and compliance risk, especially when each license or project is ring-fenced.

Can limit further exploration and development, as deductions for new projects may not be claimable.

Complexity arises when different taxes have different ring-fencing rules (e.g., resource rent tax is ring-fenced but corporate income tax is not).

Impact on Government Revenues

Ring fencing accelerates government tax receipts by preventing companies from offsetting new project costs against profits from existing taxable projects.

Without ring fencing, tax collection may be postponed, potentially reducing intended tax revenues.

Prevents companies from allocating costs disproportionately to higher-taxed areas to reduce overall tax liability.

In countries with progressive taxes, area-based ring-fencing ensures that “excess profits” are taxed appropriately, even if the company’s overall profit is low or negative.

Question 6

Carbon taxes and emissions trading schemes are intended to reduce carbon emissions and mitigate the risks of climate change in the following ways.

Price signal to reduce emissions

Carbon taxes increase the cost of fossil fuels, encouraging businesses and households to reduce energy consumption and adopt cleaner alternatives.

Encouragement of low-carbon innovation

By making carbon-intensive activities more expensive, carbon taxes incentivize firms to invest in renewable energy, energy efficiency, and low-carbon technologies.

Evidence from implementation

Countries such as Sweden and British Columbia in Canada have experienced noticeable declines in emissions and fossil-fuel use after introducing carbon taxes while maintaining economic growth.

Cost-effective climate policy

Carbon taxes allow the market to determine the most efficient ways to reduce emissions, often making them more economically efficient than rigid regulatory approaches.

Revenue generation for climate policies

Governments can use carbon tax revenues to fund renewable energy projects, climate adaptation measures, or reduce other taxes, improving overall policy effectiveness.

Limitations and challenges

If the tax rate is too low, it may not significantly change behaviour. Industries may relocate to countries without carbon pricing (carbon leakage). Carbon taxes may increase energy prices and disproportionately affect low-income households if not accompanied by compensatory measures.

Emissions trading schemes (ETS) are market-based policies that cap total greenhouse gas emissions and allow firms to buy and sell permits. They are generally effective in reducing emissions by setting a declining cap that incentivises companies to cut pollution at lowest cost.

Evidence from schemes like the EU ETS shows significant reductions in some sectors, though results vary across countries and industries.

However, effectiveness can be limited by allowance oversupply, price volatility, and carbon leakage concerns.

Overall, ETS can play an important role in climate mitigation, but it requires strong regulation, tightening caps, and complementary policies to ensure deep long-term emission reductions and avoid unintended market distortions that weaken environmental outcomes over time across the global economy and related sectors.

Question 7

Unitisation fundamentally treats the shared geological reservoir as a single joint venture unit for operational and fiscal purposes, overriding the original separate license boundaries. This requires the alignment of accounting mechanisms and tax reporting between technically distinct ownership groups to ensure consistency in calculating fiscal liabilities.

Redetermination retroactively adjusts the "Equity Share" of each participant based on updated geological data (e.g., new seismic surveys or production histories). From a tax perspective, this means the historical allocation of revenues, costs, and profits was technically incorrect, necessitating complex fiscal true-ups and adjustments to prior tax filings.

To rectify this historical imbalance, "Balancing Payments" are required. These payments compensate the party whose newly determined share is smaller (meaning they overpaid for historical field development) by the party whose share has newly increased (the under-payer). Tax authorities heavily scrutinise the nature and commercial justification of these true-up payments.

Payment for past "Operating Expenditure" (OPEX) is generally treated as a tax-deductible adjustment for the paying party, as it represents ordinary business expenses for field operations. Conversely, the receiving party must typically recognise this reimbursement as taxable income or a reduction in their current year deductible OPEX, increasing their immediate tax burden.

Payment for past "Capital Expenditure" (CAPEX) is treated differently than OPEX; it is generally viewed as an acquisition of a tangible or intangible asset. The paying party is essentially buying into existing infrastructure (e.g., pipelines, platforms) and will seek to capitalise this payment to claim future depreciation or capital allowances.

Balancing Charge vs. CGT: For the receiving party, the balancing payment for past CAPEX may be treated as a partial "Disposal" of their license interest, triggering Capital Gains Tax (CGT). Alternatively, many jurisdictions treat it as a "Recapture of Capital Allowances" (a Balancing Charge), effectively clawing back previous tax deductions and taxing the receipts at the standard corporate tax rate rather than a potentially lower CGT rate.

The "Cost Basis" or adjusted tax value of the license and underlying assets must be recalibrated for both parties post-payment. This ongoing adjustment impacts the calculation of future depletion, depreciation, and amortisation (DD&A) allowances over the remaining life of the unitised field.

The issue of "Asset Step-up" is critically important. It must be determined whether the host state's tax authority allows the payer to depreciate the balancing payment based on the newly assessed economic value of the infrastructure, or if they are strictly restricted to the original historical cost basis, which could severely limit their tax deduction benefits.

Cross-border unitisation (e.g., a reservoir straddling the Exclusive Economic Zones of Country A and Country B) introduces highly complex tax treaty issues. It raises jurisdictional challenges regarding the allocation of taxing rights, the potential for double taxation on balancing payments, and the application of specific bilateral field agreements.

Characterisation of "Interest": Balancing payments almost always include a substantial interest component to account for the time value of money between the original expenditure and the redetermination date. A pivotal tax issue is whether this is legally classified as "interest" (making it subject to Withholding Tax, thin capitalisation rules, and corporate interest restriction limits) or simply an economic uplift rolled into a unified Capital Purchase Price.

There is a significant impact on "Cost Oil" recovery in Production Sharing Agreement (PSA) regimes. The parties must negotiate, and the host government must approve, whether the balancing payment qualifies as newly recoverable "Cost Oil" for the payer, and correspondingly, whether the receiver must remove that equivalent amount from their historic cost recovery pool to prevent double-dipping.

Withholding Tax (WHT) risks are prevalent on cross-border balancing payments. If the true-up payment flows between non-resident partners in different jurisdictions, the host state may assert that the OPEX reimbursement, management fee components, or embedded interest are subject to domestic WHT at source, leading to cash leakage.

Adjustments to equity shares often trigger indirect taxes, such as stamp duty, transfer taxes, or registration fees. Tax authorities may view the redetermination and corresponding balancing payment as a legal transfer or assignment of a real property right or intangible license interest, assessing taxes on the gross transaction value.

The VAT treatment of the transaction must be carefully managed. The balancing payment might be categorised as a taxable supply of services or assets, requiring VAT to be charged and recovered, which creates massive temporary cash-flow burdens. Alternatively, some jurisdictions allow it to be treated as an "out-of-scope" true-up arrangement.

The use of "Tax Stabilisation" clauses in the original concession or PSA is a vital defence. Parties will attempt to invoke these clauses to protect against adverse or novel tax interpretations strictly surrounding unitisation rules, ensuring that redetermination payments are taxed under the transparent regime expected at the time of the original contract signing.