RESOURCES for DEVELOPMENT CONSULTING

Green Hydrogen Organisation

November 2022

Sustainable Fiscal Regimes for the Development of Green Hydrogen:

Perspectives for Developing Country Governments

Don Hubert (PhD) – President, Resources for Development Consulting

The large-scale green hydrogen developments hold the promise of transforming global energy markets and hastening the energy transition. The top-of-mind challenge is to incentivize billion-dollar investments to turn that promise into reality. Many proposed projects – half of those announced in 2021 – are in developing countries where green hydrogen exports will be the anchor that enables the initial investments. There are unique dynamics for large-scale energy export projects with capital budgets that can rival the host government's GDP, many of which revolve around governments receiving a fair share of project revenues.

Incentivizing investment in energy projects often comes at the expense of the host country's revenue interests. It is frequently simply assumed that multi-billion-dollar investments will generate positive economic and revenue benefits in the host country. However, decades of experience in developing countries, particularly in the petroleum sector, demonstrate that governments commonly do not secure a fair share of their natural resources that wealth. In the absence of fit-for purpose fiscal regimes for the development of green hydrogen, there is a risk that the mistakes of the past will be repeated.

Given the variation in the kinds of projects being proposed, there can be no blanket recommendations. This note seeks to set out some high-level considerations that could help developing country governments protect their country's revenue interests even while incentivizing large-scale investment. While many of these considerations have broad applicability, they are most directly targeted towards projects anchored around the export of green hydrogen / green ammonia (See Figure 1).

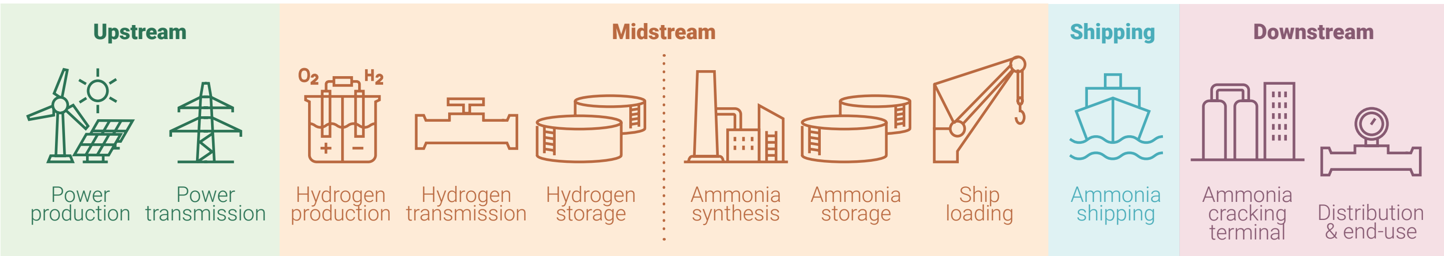

Figure 1: The Green Hydrogen / Green Ammonia Value Chain

Conduct Rigorous Economic Analysis

Analyze Fiscal Options through Dedicated Economic Models: Green hydrogen projects will be complex investments. With few projects, yet developed at scale, there are substantial uncertainties on most of the key variables including capital, operating and feedstock energy costs, and future market dynamics for the sale of green hydrogen. Analysis of these complex dynamics requires sophisticated economic models of each individual project, the integrated value chain, and an integrated country model. Company models should be provided to governments for careful analysis. However, dedicated project/sector models must be developed to fully understand the fiscal implications for the government of the investments under varying scenarios of production volumes, project costs and market prices.

Fiscal Regime Analysis Starts from Commercial Structure: Existing proposals for the development of green hydrogen in countries such as Egypt, Mauritania, Morocco, and Namibia suggest that there is considerable variation in company ownership along the value chain. The allocation of risks and benefits between different corporate entities, and the opportunities for the government to secure revenue benefits, differs depending on the specific commercial structure. It may be helpful to consider the three broad models that have evolved for LNG projects: integrated, tolling, and merchant (See Figure 2).

Integrated model: A single corporate entity owns and operates all parts of the value chain from the production of renewable energy feedstock through to the production, storage, and transportation of green hydrogen / green ammonia, to the sale at point of export or destination market. Common ownership of the feedstock renewable energy and the green hydrogen plant appears to be the approach. For example, for Chariot / Total Eren's Nour project in Mauritania, Total Eren's Guelmim-Oued Noun project in Morocco and Hyphen's Tsau Khaeb project in Namibia.

Tolling model: Separate investors own and operate the green hydrogen / green ammonia plant and are paid a per-unit fee for processing. The original energy producers retain title to the energy throughout and sell at the point of export or destination market. A description of this model can be found in the Prefeasibility study for a hydrogen export project in Chile.

Merchant model: The corporate entity that owns and operates the green hydrogen / green ammonia plant purchases renewable energy through long-term offtake agreements. Plant owners take title to the energy, process it, and sell at the point of export or destination market. A green hydrogen producer, purchasing certified renewable energy from the grid, appears to be the approach, for example, in Scatec's Ain Sokhna project in Egypt.

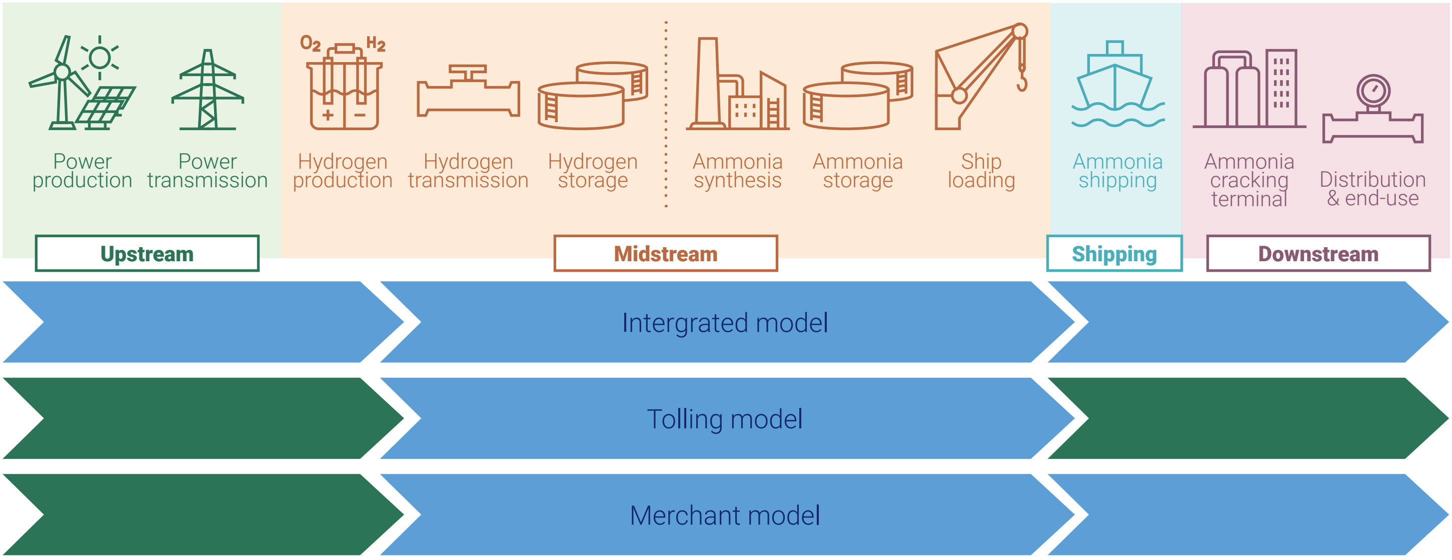

Figure 2: Models of Possible Commercial Structures for Green Hydrogen Production and Export

Financing will Drive the Projects based on Long-term Bankable Offtake Agreements: Concessional financing will be essential to de-risk green hydrogen projects and move them towards investment decisions. Development finance institutions can provide concessional or soft loans, equity and guarantees, and export credit agencies may also provide loans and guarantees to support participation and commercial interests from their countries. These public and multilateral institutions will help bring private banks and investors on board. Sponsors will ultimately rely on long-term offtake agreements with credit-worthy buyers for the bulk of nameplate capacity. These offtake agreements usually take the form of a take-or-pay commitment but may also require a similar corresponding commitment for the energy suppliers to the project to send-or-pay. Financiers can also be expected to prioritize the higher priced export market, potentially at the expense of domestic market commitments.

Analyze Underlying Assumptions Carefully: Amid the enthusiasm of a burgeoning new sector, hard-headed analysis is essential. Bold proposals are needed. So too are detailed feasibility studies to ensure project viability over the coming decades. Numbers can sometimes take on a life of their own, but they are only as good as the underlying assumptions. A study on feasibility studies in the mining sector indicates that companies tend to over-estimate production volumes and future prices, while underestimating costs and timelines to production. Companies should be required to submit comprehensive development plans, along with supporting economic models, for government review and approval. Once approved, these plans provide a baseline for ensuring that the company stays within agreed technical and commercial parameters and contracting strategies and meets its environmental and social commitments.

Input Costs Risk: Cost estimates for large-scale green hydrogen export projects are untested. It is essential to understand the cost estimates, and the range of uncertainty, along the entire value chain. Comparisons should also be made for potential projects developed at different times in the future given that the cost of key inputs, particularly certified renewable feedstock energy and the cost of electrolyzers, will fall as technologies are refined and they are produced at scale. Stylized cost estimates for the main elements of green hydrogen production, based on public domain sources, are shown in Table 1. A comparison is provided for an LNG project assuming shipping from East Africa.

Table 1: Value Chain Elements with Stylized Costs for a Green Ammonia Export Project (USD)

Unit Cost per Ton of Ammonia*	Unit Cost per MMBTU	Cost Elements	Unit Cost per MMBTU of LNG
30	1.00	Plant operating costs	1.00
120	4.00	Capital costs to build plant including financing	3.00
100	3.33	Cost to convert hydrogen to ammonia	N/A
40	1.33	Cost to transport from Africa to Europe	2.00
150	5.00	Cost to reconvert to useable energy	0.30

**1 metric ton of ammonia is assumed to have an energy equivalent of 30 MMBTU.*

Market Risk: The lack of an established international market for hydrogen and ammonia, compounded by wide energy market fluctuations, means that future market prices are highly uncertain. This market risk is heightened by the likely importance of price subsidies and carbon taxes in destination markets.

Be Skeptical of Economic Benefits Analyses and Employment Estimates: Companies commonly highlight the wider economic benefits, local content opportunities, and employment estimates to encourage government buy-in. Decades of experience in the petroleum sector, however, suggests that these numbers should be approached with caution. Economic benefit analyses are commonly based on a multiplier effect that is usually mis-calibrated for developing-country economies. While opportunities to maximize local content should be pursued, these commonly fall far short of targets and may increase corruption risks. Furthermore, capital intensive industries generate comparatively fewer long-term jobs per dollar of investment than other sectors such as manufacturing.

Design Fit-for-Purpose Fiscal Terms

Carefully Consider Fiscal Incentives and Evaluate Them: Companies will seek fiscal concessions, even when they are not essential for the investment decision. Governments commonly offer fiscal incentives without considering their necessity or their long-term revenue implications. Worse still, governments rarely cost out fiscal concessions or conduct meaningful cost-benefit analyses. Fiscal incentives may be appropriate, but governments should be explicit on what they are offering, why it is necessary, and what it will cost.

Incentivize Good Performance: Fiscal incentives are commonly offered irrespective of the performance of the company. While it is always hard to see the future, there are three simple metrics for assessing company performance: did production begin on schedule, are production volume targets being met, and was construction completed on budget. Government interests are harmed by poor company performance. Tying investment incentives to good performance helps to align interests.

Guarantee Some Early-Year Government Revenue: Contracts that enable multi-billion-dollar investments but result in no government revenue until the projects achieve profitability are unsustainable. While royalties were traditionally seen as compensation for the depletion of a non-renewable resource, they are now mainly used to guarantee some government revenue prior to project profitability. A per unit royalty would likely be the most appropriate, given that market value may be affected by destination market subsidies. Rates should be kept low as royalties are paid irrespective of the company return but may still generate significant government revenue (see hypothetical examples in Box 1). To minimize complexity in the early years, royalty payments should be taken in cash and not in kind.

Box 1: Per Unit Royalty Example

A hypothetical project produces 500,000 tons of green hydrogen per year or around 2.8 million tons of ammonia.

Estimated costs to export are shown inTable 1, plus around $150 per ton for renewable feedstock electricity.

A royalty of $9 per ton would generate around $25 million yet would be only about 2% of the breakeven FOB cost.

A royalty of $22 per ton would generate around $61 million yet would be only about 5% of the breakeven FOB cost.

Green hydrogen production (tons)	500,000	
Equivalent output of ammonia (tons)	2,800,000	
Estimated costs to export ($/ton)	430	
Royalty rate on ammonia sales ($/ton)	9	22
Annual royalty payment ($ million)	25	61
Royalty as % of breakeven FOB price (%)	2	5

Consider Carefully whether a Corporate Income Tax Regime is Sufficient: Outside of a fit-for-purpose fiscal regime, the default fiscal instrument will likely be corporate income tax, combined with accelerated depreciation. However, general corporate income tax terms may not be well-suited to investments with dollar-values that may exceed the size of the host country's GDP. Corporate income tax is assessed on net income (income after costs) and therefore no payments should be expected on billion-dollar investments for many years. While corporate income tax is responsive to profitability, the government loses revenue if operators perform inefficiently (e.g., cost overruns, plant shut-ins, inability to meet contractual commitments). Furthermore, complex energy projects create opportunities for companies to optimize their taxes, including through transfer mispricing. Finally, corporate income tax is not an effective way for governments to capture significant upside. If corporate income tax is part of the mix, accelerated depreciation and investment tax credits could be linked to good company performance. Care should be taken with tax holidays that often undermine government revenue interests more than initially expected.

Add Mechanisms to Capture a Share of the Upside: The contracts being negotiated now will last for decades, and circumstances can change profoundly even in a few years. Well-designed fiscal regimes share revenues fairly under conditions of both marginal and windfall returns. High company profits and low government revenues make contracts unsustainable. Windfall profit taxes are often suggested, though in the petroleum sector they have not proven to be effective in developing countries. Trigger mechanisms could be added to contracts requiring a renegotiation if there are fundamental changes to main variables such as changes in international subsidies or the introduction of new technologies that impact costs.

Consider Capturing Upside through a Share of Production: An alternative is for the government to take a share of production once the project becomes profitable. For example, the government could receive a percentage share of production, increasing incrementally at either pre-established price thresholds (after project payout), or based on some measure of profitability (r-factor or company IRR). This share could be taken either in cash or in kind. Where the export market is the project anchor, there may be value in reorienting some share of production to the domestic market after initial investment costs have been recovered.

Limit the Scope and Timeframe of Stabilization Clauses: Companies investing in multi-billion-dollar international energy projects expect guarantees that the original fiscal terms will remain unchanged. Experiences from the petroleum sector indicate that these clauses are often written too broadly and bind only one of the parties: companies routinely ask for follow-on fiscal concessions if fundamental dynamics change, but governments have agreed not to do the same. Best practice is to avoid blanket stabilization for the lifespan of the contract and instead stabilize specific provisions for a limited timeframe.

Make contracts public: Secrecy breeds suspicion, even where that suspicion is unwarranted. It is becoming common for petroleum contracts to be publicly disclosed. Claims of commercial confidentiality have been shown to be unfounded. Competitor companies and industry insiders almost always know the relevant contractual terms, while many government officials, parliamentarians, and journalists remain in the dark. With green hydrogen there is an opportunity to make full disclosure of contracts an industry standard right from the outset.

Protect Government Revenues

Think about Potential Government Revenues from the Start: Government representatives who negotiate contracts for major energy projects are tasked with attracting inward investment. In most cases, they are not explicitly asked to also prioritize securing a fair share of revenues for the government over the lifecycle of the project. The entities responsible for government revenues such as the Ministry of Finance and the Revenue Authority often only become involved many years later when expected revenues fail to materialize. The national economic interest requires promoting investment and protecting government revenue interests.

Conduct Anticipatory Revenue Risk Assessments: Negotiating a fair deal is only the first step. It is common for actual government receipts to fall far short of forecasts, even when controlling for costs and prices. This is because complex energy projects create many opportunities for companies to optimize their taxes both by under-reporting revenues and over-reporting costs. Dozens of real-world examples are collected in Many Ways to Lose a Billion: How Governments Fail to Secure a Fair Share of their Natural Resource Wealth. Many of the risk areas can be anticipated based on potential weaknesses in contracts and legislation, peculiarities of the specific commodity and how it is produced, transported, and sold, and the corporate structure of the project owners including the number and location of their subsidiaries. Governments should conduct anticipatory revenue risk assessments to map the various risks, to assess the likelihood and quantify the potential impact of those risks, and to develop mitigation strategies.

Don Hubert is the president of Resources for Development Consulting (www.res4dev.com). The firm specializes in assisting governments to secure a fair share of natural resource wealth by helping to design fiscal regimes, negotiate contracts, forecast future government revenues, and monitor and audit production, sales, and project costs. Their analysis is grounded in industry-standard project-specific and sector wide cashflow models. To help level the playing field for governments, they engage world-class industry experts but to avoid any conflict of interest never work for natural resource companies. As part of their work, Don Hubert has reviewed hundreds of extractive sector contracts and conducted detailed economic analyses of large-scale petroleum and mining projects in more than twenty countries. He is the author of Many Ways to Lose a Billion: How Governments Fail to Secure a Fair Share of Natural Resource Wealth. He holds a PhD from the University of Cambridge, UK.