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Editor: IAEE Headquarters

PRESIDENT'S MESSAGE

Dear IAEE Members,

This summer, our international IAEE community came together in Santiago for the 47th IAEE International Conference. The conference provided a timely opportunity to discuss the profound changes taking place across global energy systems and to exchange perspectives from across the Americas and beyond.

Energy security, affordability and decarbonization remain closely intertwined, but the challenges and possible solutions differ considerably across countries and regions. The Americas illustrate this diversity particularly well, encompassing major energy producers and exporters, rapidly transforming electricity systems, abundant renewable resources, and very different economic and policy environments.

Following our first regional issue on Asia-Oceania, this edition of the Energy Forum therefore turns to **The Americas**. It brings together perspectives from across the region and continues many of the discussions we had in Santiago.

I would like to thank our colleagues in Chile and across Latin America for their tremendous efforts and warm hospitality, as well as all speakers, authors, sponsors and participants who made the conference such a success.

I hope you enjoy this issue and the perspectives it brings together.

Yours sincerely,
Aaron Praktiknjo
President, IAEE

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The Moving Frontier of Energy Scarcity: Reflections from Santiago

BY RICARDO RAINERI

Energy technology is advancing at an extraordinary pace. The costs of solar power, batteries, and many other energy-transition technologies have fallen sharply. Investment has expanded, and electrification is reaching new sectors of the economy. Yet energy systems do not appear less constrained. Concerns over electricity reliability, transmission, affordability, critical minerals, energy security, and investment risk have become more, not less, prominent.

That apparent contradiction was one of the most striking impressions emerging from the 47th IAEE International Conference in Santiago. The conference opened with a high-level dialogue on Global Energy Security in a Fragmented World and closed with a discussion on the Economics and Geopolitics of Energy in Latin America and the Caribbean. In between, eight Dual Plenary Sessions examined flexibility and resilience, the future of oil and gas, electricity-market design, critical minerals, energy finance, enabling infrastructure, energy access and regional integration, and transport transformation. A broad research program extended discussion across energy markets, technology, investment, affordability and the changing organization of energy systems.

At first sight, these may appear to be separate energy-economics problems. Taken together, however, they point toward a deeper development. The energy transition is not simply eliminating scarcity. It is reorganizing it.

Technological progress relaxes some constraints faster than the complementary capabilities of energy systems can adjust. As that happens, scarcity, and therefore economic value, investment risk, and political attention, move elsewhere in the system.

Scarcity does not disappear; it moves

Energy economics has always been fundamentally concerned with scarcity. Historically, much of that scarcity was tied to access to primary energy resources, coal, oil, gas, hydroelectric potential, or to the capital and technologies needed to transform them into useful energy. More recently, technological progress

and decarbonization have begun to alter not only the generation mix but also the underlying economics and organization of energy systems (Raineri, 2025).

What the discussions in Santiago suggest is that this transformation may also be changing where scarcity itself resides. As some technological constraints are relaxed, complementary capabilities can become the new binding constraints.

This becomes particularly important when technological change advances faster than the complementary capabilities required to integrate it. Generation may become cheaper and more abundant while transmission remains constrained; storage technology may advance faster than market arrangements for valuing flexibility; new sources of electricity demand may emerge faster than the infrastructure required to serve them. In such cases, scarcity has not disappeared. It has moved.

Electricity provides perhaps the clearest example. A conventional generating unit historically supplied several attributes together. It produced energy, could often respond to changes in demand, contributed to system adequacy and, depending on the technology and location, supplied other grid services. As the generation mix changes, some of those attributes become increasingly unbundled.

Solar generation can produce very inexpensive electricity at midday while electricity during a low-renewable hour remains scarce. A system may have abundant annual generation while lacking transmission at a particular location, flexibility over a particular interval, interconnection capacity for a new project, or firm capacity during a critical period.

Scarcity therefore shifts from simply producing another megawatt-hour to producing or transporting the right megawatt-hour, at the right location, at the right time, and with the attributes the system requires.

That distinction was visible throughout the Santiago program. Flexibility, storage, grids, and resilience formed one Dual Plenary Session; electricity-market design another; and enabling infrastructure yet another. These are not simply separate engineering problems. Economically, they are different manifestations of a changing structure of relative scarcity.

This matters because markets allocate scarce resources. When what is scarce changes, market arrangements developed around yesterday's scarcity may no longer reveal the value of tomorrow's scarce attributes.

Markets designed for yesterday's scarcity

For much of the development of competitive electricity markets, energy occupied a central role in market design.

Capacity, reserves and ancillary services were also important, but many valuable system characteristics arrived bundled with conventional generation and therefore did not always require separate economic valuations.

Technology is increasingly separating those characteristics.

Low-marginal-cost generation alters hourly price patterns. Storage can consume electricity in one period and supply it in another. Flexible demand can perform functions previously provided by generators. Distributed resources are reshaping the relationship between networks and consumers. Large new loads, from data centers to electrified industrial activity, can emerge faster than transmission or generation infrastructure can be expanded.

The economic challenge is therefore not merely to accommodate new technologies. It is to identify which complementary capabilities are becoming scarce and to determine whether the market and regulatory architecture allow those capabilities to be valued and supplied.

This creates a subtle shift in the role of market design. A market that works well when energy itself is the primary scarce product may perform poorly when the principal constraints are deliverability, ramping capability, firm supply, transmission access, or the speed at which new resources can connect.

The electricity-market discussions in Santiago were consequently part of a broader question: how should markets evolve when technological change alters the object of scarcity itself?

That question is increasingly important in the United States. Transmission constraints, interconnection queues, rapid growth in electricity demand in some regions, reliability concerns, and the expansion of storage are forcing U.S. markets and regulators to reconsider how investment signals are created and which system attributes must be compensated.

Chile approaches the problem from a somewhat different direction, following very rapid renewable penetration and the emergence of significant curtailment, storage, and transmission challenges. Yet the underlying economics increasingly converge.

Different systems can arrive at the same problem from different directions.

From energy security to system security

A similar migration is occurring in energy security.

The traditional concept of energy security focused heavily on access to fuels, especially oil and natural gas. Those concerns remain important, as reflected in Santiago's discussion of the future of oil, gas, and diversification. But decarbonization and electrification do not simply eliminate dependence. They alter its composition.

Renewable technologies reduce reliance on continuously purchased fossil fuels while increasing the

importance of electricity networks, storage, equipment manufacturing and mineral supply chains. Electric vehicles reduce oil dependence but increase dependence on batteries, electricity infrastructure and specific materials. Digitalization can make systems more efficient while also making them more dependent on communications, control systems and reliable electricity.

Critical minerals offered a particularly clear illustration of this changing geography of scarcity. As energy systems become less dependent on certain continuously consumed fuels, they can become more dependent on the materials, processing capacity, technologies, and supply chains required to build the new system. Santiago approached this not simply as a resource question but as one involving geographic concentration, industrial strategy, investment, and geopolitical exposure. A dedicated Dual Plenary Session on **Critical Minerals, Supply Chains, and the Geo-Economics of Energy Transition** brought together perspectives from the United States, China, Indonesia, and Chile, countries occupying very different positions in these emerging value chains.

Copper, lithium, rare earths, processing capacity, and manufacturing have become increasingly intertwined with industrial strategy and geopolitical competition. For Latin America, these developments create substantial opportunities but also raise difficult questions about investment, value creation, environmental performance, and the durability of comparative advantage. For the United States and other importing economies, the emphasis is increasingly on diversification, supply security, and resilience.

The object of energy security is therefore broadening.

It is no longer only about securing fuels. It is increasingly about securing the capabilities that allow an energy system to function: networks, materials, technologies, flexibility, infrastructure, capital and institutional capacity. Yet the availability of these elements individually does not guarantee security. As energy systems become more technologically diverse and interdependent, success increasingly depends on the ability to develop and orchestrate complementary capabilities at the pace required by the transition.

This may be better understood as a movement from commodity security toward system security. The relevant question is no longer simply whether a country can secure a particular fuel or resource, but whether the system as a whole can assemble, coordinate and adapt the capabilities required to deliver reliable and affordable energy.

The affordability paradox

The same process helps explain another apparent contradiction.

The costs of several technologies transforming electricity systems, notably solar generation and batteries, have fallen substantially. Yet concerns over electricity affordability have not disappeared.

There is no inconsistency if technology cost and system cost are distinguished.

Consumers do not purchase an annual average megawatt-hour produced at the lowest possible technological cost. They purchase an energy service available when and where it is required, with an expected level of reliability.

A generation technology can therefore become cheaper while the system simultaneously requires greater investment in transmission, storage, flexible capacity, resilience, distribution networks, or other complementary resources.

Put differently: Lower technology cost does not automatically mean lower system cost.

This is not an argument against renewable technologies. It is an argument for evaluating them as parts of an interconnected system rather than as stand-alone production technologies.

The distinction also has important distributional consequences. Costs associated with networks, legacy assets, public policies and new infrastructure must ultimately be allocated among consumers, producers, taxpayers and investors. How those costs are allocated increasingly affects the political sustainability of the transition itself.

These questions also ran through Santiago's discussions of energy finance, infrastructure, access, efficiency and energy poverty.

Affordability is therefore not simply an additional objective to place beside decarbonization and reliability. It is partly an outcome of how societies identify, finance and allocate the costs of the scarcities that emerge as energy systems transform.

When technology risk falls, coordination risk may rise

There is another consequence.

As technologies mature, technology risk may decline. Yet the investment required around those technologies can become increasingly dependent on decisions elsewhere in the system.

A transmission investment may depend on where generation develops. Storage revenues depend on market design and price patterns. A low-carbon industrial investment may depend simultaneously on electricity prices, infrastructure, regulation and access to finance. The value of one project can therefore depend on complementary investments that its owner does not control.

As a result, technology risk can fall while system and coordination risk rise.

This helps explain why energy finance remains difficult even in sectors where technologies themselves are increasingly well understood.

It also changes the relationship between markets and planning. The relevant debate is no longer well captured by a simple opposition between centralized planning and competitive markets. Modern energy systems require both decentralized investment decisions and coordination of networks, infrastructure and other shared capabilities.

The economic question is how to allocate decisions and risks so that one can reinforce the other rather than undermine it.

Different regions, a common economic problem

One of the advantages of an international conference is that similar problems can be viewed from very different starting points.

Chile's electricity system reflects rapid renewable deployment and the emerging economics of storage, curtailment and transmission. The United States is confronting rapid technological change together with potentially very large new sources of electricity demand. Europe has combined decarbonization with renewed concerns over security and industrial competitiveness. Developing economies must simultaneously address transition, investment, access and growth.

Latin America's circumstances differ again, with large renewable resources, substantial critical-mineral endowments and major opportunities for regional integration, but also significant investment and institutional constraints. The closing discussion in Santiago deliberately placed these questions within the changing global economic and geopolitical environment.

These are not identical transitions.

Yet a common structural problem is emerging: technologies are changing more rapidly than many of the complementary capabilities on which their economic and system value depends.

When that happens, scarcity migrates.

It can migrate from fuels to minerals and supply chains; from generation to transmission; from energy to flexibility and firm delivery; from technology to enabling infrastructure; and from engineering risk to regulatory and coordination risk.

And because economic value follows scarcity, investment incentives must adjust as well.

Some of these constraints need not be physical: the ability to secure timely regulatory approval and durable social and political support for new infrastructure can itself become a binding capability.

For policymakers, regulators and investors, this suggests that transition strategies should be evaluated not only by the constraint they are intended to relieve, but also by the new constraints they may expose elsewhere in the system.

This may be one of the more important implications of the next stage of the energy transition.

The question is no longer only which technologies can produce energy at the lowest cost. Increasingly, it is which economies can identify emerging constraints early enough, create institutions capable of valuing the capabilities needed to relieve them, and coordinate investment before those constraints become expensive.

The next phase of the energy transition may therefore be determined less by who wins the technology cost race than by who learns fastest to identify, price, and relieve the scarcities that technological change leaves behind.

Reference

Raineri, Ricardo. 2025. "*Power Shift: Decarbonization and the New Dynamics of Energy Markets*." Energies 18, no. 3: 752. https://doi.org/10.3390/en18030752.

Editor's Notes

Following the IAEE International Conference in Santiago, this issue of Energy Forum brings together a selection of contributions that reflect many of the themes discussed in Chile: energy security, regional cooperation, market reform, investment allocation, and the geopolitical dimensions of the energy transition. The articles move across the Americas and beyond, examining how countries are responding to pressures on electricity systems, the growing importance of critical minerals, the need for cross-border infrastructure, and the challenge of designing policies that are both economically sound and politically workable. Together, these contributions show that the energy transition is not unfolding as a single global pathway, but through a variety of regional experiences shaped by resource endowments, institutional capacity, trade relationships, and strategic choices.

Aditi Sarkar examines Brazil's critical minerals industry and its growing importance in global clean energy supply chains. The article highlights Brazil's substantial reserves of niobium, graphite, nickel, and manganese, and considers how these resources position the country within the strategic competition among China, the United States, and the European Union. It shows that Brazil's role in critical minerals trade is not only an industrial opportunity, but also a key question in the diversification of global supply chains.

Pablo Benalcázar, Wilian Guamán, and Alisson Esparza analyze whether Ecuador can sustain a fully renewable electricity system while managing the risks created by hydrological stress. Their article compares a business-as-usual pathway with a 100% renewable electricity pathway to 2050, evaluating how each performs under normal and low-water conditions. By examining the role of solar, wind, geothermal, and bioenergy in reducing dependence on hydropower, the study offers wider lessons for hydro-dependent electricity systems across Latin America.

Tomasz P. Wiśniewski explores the emerging global energy rivalry between a U.S.-led hydrocarbon-oriented bloc and a China-led electrification-oriented bloc. The article examines the structural factors that may shape countries' alignment with either pole, including resource endowments, energy systems, governance structures, and geopolitical alliances. It argues that a third group of balancing economies may play a decisive role in shaping the future direction of global energy transition and geoeconomic competition.

Julia Frayer and Javier Maquieyra address a central question in electricity market design: how markets can better reflect the levels of reliability that customers are willing to pay for. Their article distinguishes between the traditional Value of Lost Load metric and the growing potential for voluntary demand-side participation through distributed energy resources, batteries, and virtual power plants. Using simulations based on the ERCOT market in Texas, the authors show how even modest residential flexibility can create meaningful consumer benefits and improve system efficiency during tight market conditions.

Juan A. B. Belt considers Cuba's power sector at a moment of severe economic and electricity supply crisis. The article develops a reform and financing framework for a future transition government, combining emergency stabilization, regulatory reform, distribution company strengthening, social protection, and long-term investment in gas-fired generation, solar, and storage. It places reliable electricity at the center of any successful economic transition and argues that U.S. energy diplomacy toward Cuba should be planned before a political transition occurs, rather than improvised afterwards.

Jiyeong Pyo examines how U.S. federal energy and environmental investments were allocated across states between 2021 and 2024. The article asks whether funding was driven primarily by climate hazard exposure, population, or public demand for climate action. The analysis finds that allocations were mainly demographically scaled and modestly responsive to public climate concern, rather than strongly targeted toward disaster exposure, raising broader questions about how governments design fair and effective energy investment programmes.

Joaquín Corvalán Azpiazu turns to the growing problem of renewable energy curtailment in South America. The article argues that international electricity interconnections offer a practical and underused mechanism to absorb renewable surpluses and reduce economic, environmental, and operational losses. Drawing on the Chile–Argentina InterAndes interconnection, it identifies regulatory design features that could be replicated through bilateral arrangements, offering a pragmatic pathway toward deeper regional electricity integration.

Michał Thlon reflects on what the European energy crisis of 2021–2023 can teach the Americas about the security value of electricity interconnection. The article argues that infrastructure originally justified on market-efficiency grounds proved essential for supply security, while storage and diversification became crucial short-term buffers. Applying these lessons to Central and South America, it highlights the importance of physical transfer capacity, institutional trust, and technical readiness in building resilient regional power systems.

Monica Pereira Henriques, Boris Ortega and Gilbert Fridgen examines whether carbon pricing can make green hydrogen cost-competitive with other energy sources in industrial production. Using a firm-production model calibrated to Luxembourg, the article estimates the carbon price thresholds at which green hydrogen could substitute oil and natural gas. The results suggest that these thresholds are generally far above current and expected carbon prices, indicating that carbon pricing alone is unlikely to drive large-scale green hydrogen adoption and that stronger complementary policies will be needed.

100% Renewable Electricity in Ecuador: Can Diversification Offset Hydrological Stress?

BY PABLO BENALCAZAR, WILIAN GUAMÁN, AND ALISSON ESPARZA

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Abstract

Latin America and the Caribbean already obtain a large share of their electricity from renewable sources, with hydropower providing much of this contribution. In Ecuador, where hydroelectric generation accounts for about 72% of annual production, this structure has helped keep power-sector emissions relatively low but has also increased exposure to prolonged dry periods, as seen during the 2023 and 2024 episodes of electricity rationing, higher thermal dispatch, and greater use of imports. To examine the consequences for long-term expansion, the Ecuadorian system is evaluated over 2025–2050 under a BAU reference pathway and a REN100 pathway that progressively increases the minimum renewable share of domestic generation until it reaches 100% in 2050. Each pathway is solved under normal hydrology and a dry-season stress condition using the same demand, network representation, reserve requirement, and cross-border exchange limits. Generation and transmission investments are optimized jointly with monthly operation, allowing the four cases to be compared under the same physical and operating assumptions.

The results indicate that the stricter renewable requirement adds 7.2% to discounted system cost relative to BAU under normal hydrology and 9.5% when hydropower availability is reduced. Cumulative emissions fall by 19.5% and 31.4%, respectively. Meeting REN100 uses all the solar, wind, geothermal, and bioenergy capacity represented in the candidate portfolio, yet hydropower still supplies about 82% of domestic generation in 2050. This dependence becomes more important near the end of the horizon, when the renewable requirement reaches its maximum and energy not supplied approaches 2 TWh in both REN100 cases, close to 2% of annual demand. For Ecuadorian energy planning, these results indicate that a fully renewable domestic-generation target needs to be evaluated together with adequacy and with the potential contribution of storage, demand response, firm renewable resources, transmission reinforcement, and regional exchanges.

Keywords

Energy transition, hydropower, 100% renewable electricity, supply adequacy, Ecuador.

1. Introduction

Latin America and the Caribbean approach further renewable expansion from a position that differs from regions where fossil generation remains dominant. Hydropower accounts for a large part of that difference and has supported a comparatively low-carbon electricity supply, although its contribution changes with rainfall, inflows, and seasonal water conditions. IRENA (2025) projects continued renewable growth in South America, while the IEA (2021) notes that changes in river flows can reduce hydropower output during critical periods. Long-term planning in the region therefore has to consider new renewable generation together with the flexibility and transfer capability required when hydropower production departs from average conditions, an issue that is also reflected in the regional planning agenda discussed by Levy et al. (2023).

The link between low-carbon generation and hydrological exposure became particularly visible in Ecuador during the dry periods of 2023 and 2024. Hydropower provides around 72% of annual electricity generation (ARCONEL, 2026), so a persistent reduction in water availability affects a large share of both energy supply and operating flexibility. Load shedding, higher thermal dispatch, and emergency procurement during those episodes illustrate the consequences of that concentration for the power system (CENACE, 2025). From an expansion perspective, diversification is valuable when other technologies can replace part of the hydropower shortfall during dry months and when the network can deliver that alternative generation to demand centers (Benalcazar et al., 2020).

Recent literature provides useful evidence on these alternatives. For Ecuador, Sterl et al. (2026) estimate that complementarity among hydropower, solar, and wind can reduce the thermal backup required during dry periods, and Villamarín-Jácome et al. (2025) find a larger role for solar, wind, and storage as emission constraints become more stringent. Studies of other high-renewable systems also show that system cost and operation depend on the availability of complementary resources and firm capacity (Gaete-Morales et al., 2019; Sepulveda et al., 2018) relevance of these findings to Ecuador depends on whether non-hydro renewable production coincides with periods of lower water availability and on the operating flexibility available to integrate those resources.

Technology choices are also linked to network decisions and to the timing of new investment. Previous applications for Ecuador show that joint generation and transmission planning changes the location and sequence of expansion when network constraints become binding (Guamán et al., 2024). Once water-

resource uncertainty is included, the selected portfolio can change again because the economic contribution of each technology depends on the availability of the dominant resource (Guamán et al., 2025). Other Ecuadorian studies have examined high-electrification pathways and formulations that combine long- and short-term decisions (Barreto-Cuesta et al., 2024; Icaza et al., 2023), but the interaction between a progressively binding 100% domestic renewable requirement and severe dry-season stress has not been quantified for the interconnected system.

For the 2025–2050 horizon, this work evaluates the Ecuadorian interconnected system under a Business-as-Usual (BAU) reference pathway and a 100% renewable energy (REN100) pathway, each considered with normal hydrology and with reduced hydropower availability during the dry season. Demand, network representation, and key operating assumptions are kept fixed across the four cases. Differences in investment, system cost, emissions, imports, and energy not supplied can consequently be related to the renewable requirement and to the hydrological condition. The comparison assesses whether the diversification available in the candidate portfolio is sufficient to reduce hydro-dependence while preserving adequacy as the domestic renewable share approaches 100%.

2. Scenarios and analytical approach

The case study represents Ecuador's interconnected system through four domestic zones, ZNO, ZNX, ZSO, and ZSX, together with exchange nodes for Colombia and Peru. The 2025–2050 planning horizon is modeled with monthly operating decisions, and the reduced network retains the main transmission corridors together with the relative location of demand and generation. The zonal structure and the initial project portfolio follow official sector planning (CELEC EP, 2023). BAU and REN100 define two scenarios applied to this same system representation, while hydropower availability is varied between the normal and stress cases. The monthly profiles used in the two hydrological conditions are presented in Figure 1.

The optimization problem combines generation and transmission expansion with monthly system operation. New generating units and network reinforcements are selected while accounting for dispatch, reserve requirements, transfer limits, cross-border exchanges, and seasonal hydropower availability over the planning horizon. Total discounted cost includes investment, variable operation, fixed operation and maintenance, and the penalty for energy not supplied. The discount rate, reserve requirement, fuel costs, and import limits are identical in all cases, so the comparison is not affected by changes in these parameters.

Within this common formulation, BAU and REN100 differ only in the requirement imposed on domestic electricity generation. BAU allows the least-cost mix to evolve without an additional renewable target and keeps thermal capacity available throughout the horizon. REN100 progressively tightens the minimum renewable share until domestic generation is fully renewable in 2050. Because the requirement is applied to production rather than installed capacity, thermal units may remain in the system even when their annual domestic output reaches zero. Imports from Colombia and Peru are recorded separately, since their generation source is not identified, and they are excluded from the REN100 accounting.

Both policy pathways are then evaluated under two hydropower-availability conditions. Normal hydrology follows the reference seasonal pattern, whereas the stress case retains wet-season conditions and reduces the resource from September through February. Calibration uses the severity observed during Ecuador's 2024 dry season as a reference and represents a persistent dry period without extending the single worst month across the entire season. The four cases share

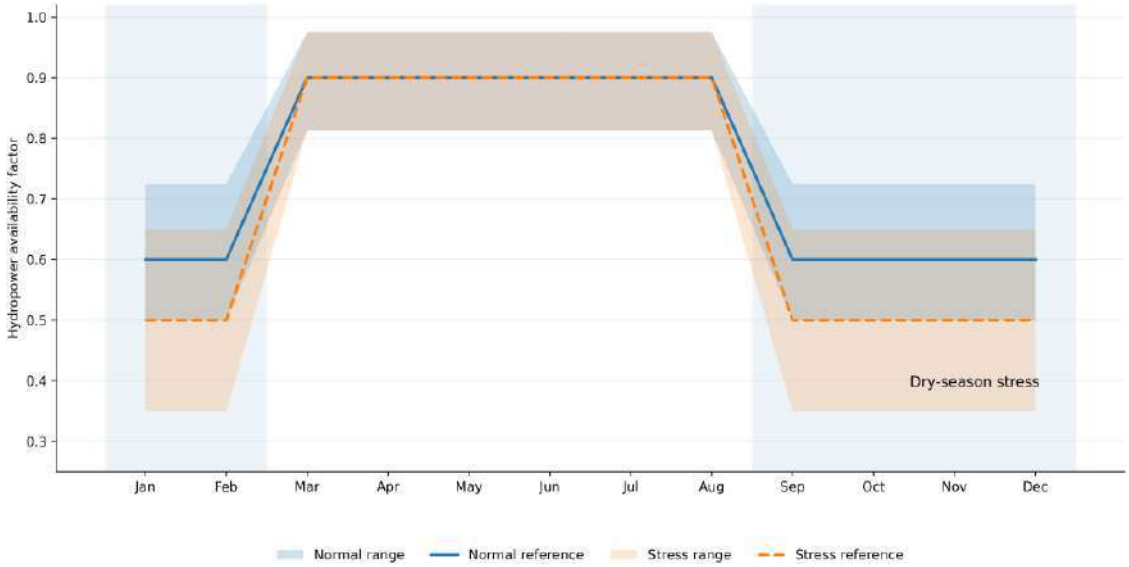

Figure 1: Monthly hydropower availability assumptions under normal and stress conditions.

Table 1: Comparative outcomes across policy and hydrological pathways

Indicator	Unit	BAU-Normal	BAU-Stress	REN100-Normal	REN100-Stress
Total discounted system cost	USD billion	29.35	34.82	31.47	38.13
Discounted investment	USD billion	15.33	18.14	17.01	21.36
Cumulative CO_2 emissions	Mt	105.18	154.84	84.67	106.30
Cumulative imports	TWh	50.64	50.29	51.13	47.40
Cumulative ENS	GWh	164.94	762.76	2,099.10	2,460.04
New generation selected	GW	14.62	16.20	16.30	19.87
Renewable share in 2050	%	89.3	88.7	100.0	100.0
2050 ENS	GWh	90.42	518.43	2,024.46	2,001.07

the same underlying pattern, so water availability is the only element that changes in the hydrological comparison. Previous work on hydro-dependent systems shows that this type of uncertainty can materially alter long-term expansion decisions (Guamán et al., 2025). The stress case is therefore used as a severe sensitivity test rather than as an estimate of drought probability.

Candidate investments were assembled from projects included in electricity-sector plans and from documented residual resource potential. Projects with identified commissioning dates retain their planned schedule through 2032; after that year, generic additions are limited to technologies for which residual potential is supported by the available information. This restriction avoids solutions based on unconstrained capacity additions in the most demanding cases. Storage is not included in the candidate set, which is relevant when the REN100 shortfalls observed near the end of the horizon are discussed. The main economic, environmental, and adequacy results for the four cases are provided in Table 1.

3. Cost, diversification, and adequacy under hydrological stress

The cost results in Table 1 indicate that the REN100 requirement becomes more expensive when hydropower availability is reduced. Under normal hydrology, discounted system cost is 7.2% higher than in BAU; under dry-season stress, the difference reaches 9.5%. The effect of hydrology is also evident within each pathway, since the move from normal to stress conditions increases BAU cost by 18.6% and REN100 cost by 21.2%. These differences accumulate as demand grows and the renewable requirement reduces the amount of fossil generation that can be used during periods of lower hydropower output.

Part of this cost difference is explained by the capacity selected over the horizon. REN100 adds more generation than BAU and reaches 19.87 GW of new capacity under hydrological stress. The solar, wind, geothermal, and bioenergy options represented in the portfolio reach their limits, after which a larger share of the remaining expansion is hydroelectric. Installed capacity in 2050 reaches 22.0 GW in REN100-Normal and 25.6 GW in REN100-Stress, with hydropower accounting for most of the difference between the two cases. Figure 2 presents the five-year capacity evolution and shows that the separation between the REN100 pathways becomes more visible after the mid-2030s.

The increase in installed capacity does not mean that every technology retains the same role in electricity supply. Under REN100, the requirement is applied to domestic generation and does not force the physical retirement of thermal units, so part of that capacity remains available even when annual fossil output falls to zero. This distinction becomes important when installed capacity is considered together with the adequacy of the final portfolio. Figure 3 places the renewable share, emissions, imports, and energy not supplied on the same 2025–2050 timeline so that this relationship can be followed through the transition.

As shown in Figure 3, REN100 reduces emissions without producing a sustained increase in cross-border purchases. Cumulative CO2 emissions are 19.5% below BAU under normal hydrology and 31.4% below BAU under stress, and direct emissions from domestic generation fall to zero in 2050. Imports from Colombia and Peru remain close to the BAU trajectory for much of the horizon and are cumulatively lower in REN100-Stress. The reduction in emissions is associated mainly with changes in domestic generation rather than with a broad substitution of fossil generation by imports.

The same figure also reveals the deterioration in adequacy toward the end of REN100. Hydropower still provides about 82% of domestic generation in 2050 after all available non-hydro renewable options have been expanded. Once the renewable requirement reaches 100%, thermal generation no longer provides the operating margin retained in BAU, and energy not supplied increases to approximately 2 TWh, close to 2% of annual demand. Most of this shortfall occurs in the final years, when the renewable constraint is fully binding, and the generation mix remains strongly dependent on water availability.

4. Planning implications

The concentration of energy not supplied near the end of the horizon changes the interpretation of a 100% renewable domestic-generation target in a hydro-dependent system. REN100 satisfies the renewable requirement, but the resulting portfolio does not preserve the same adequacy observed in BAU while

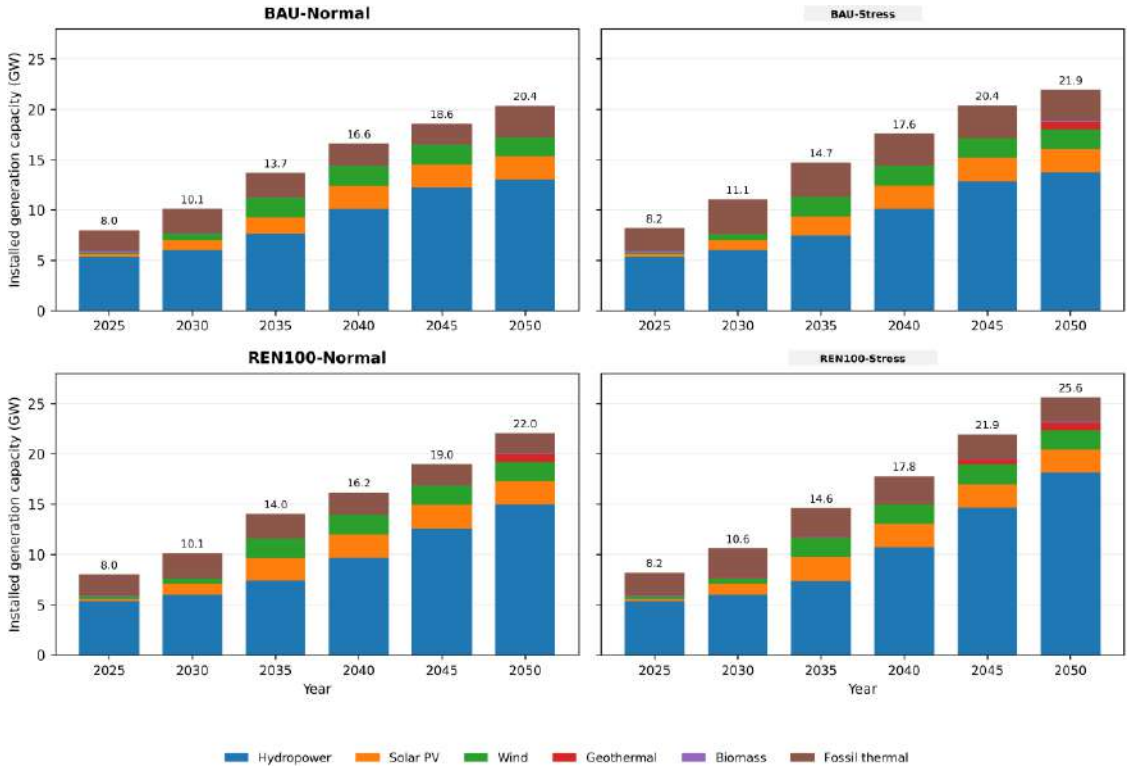

Figure 2: Installed generation capacity by technology at five-year intervals, 2025-2050.

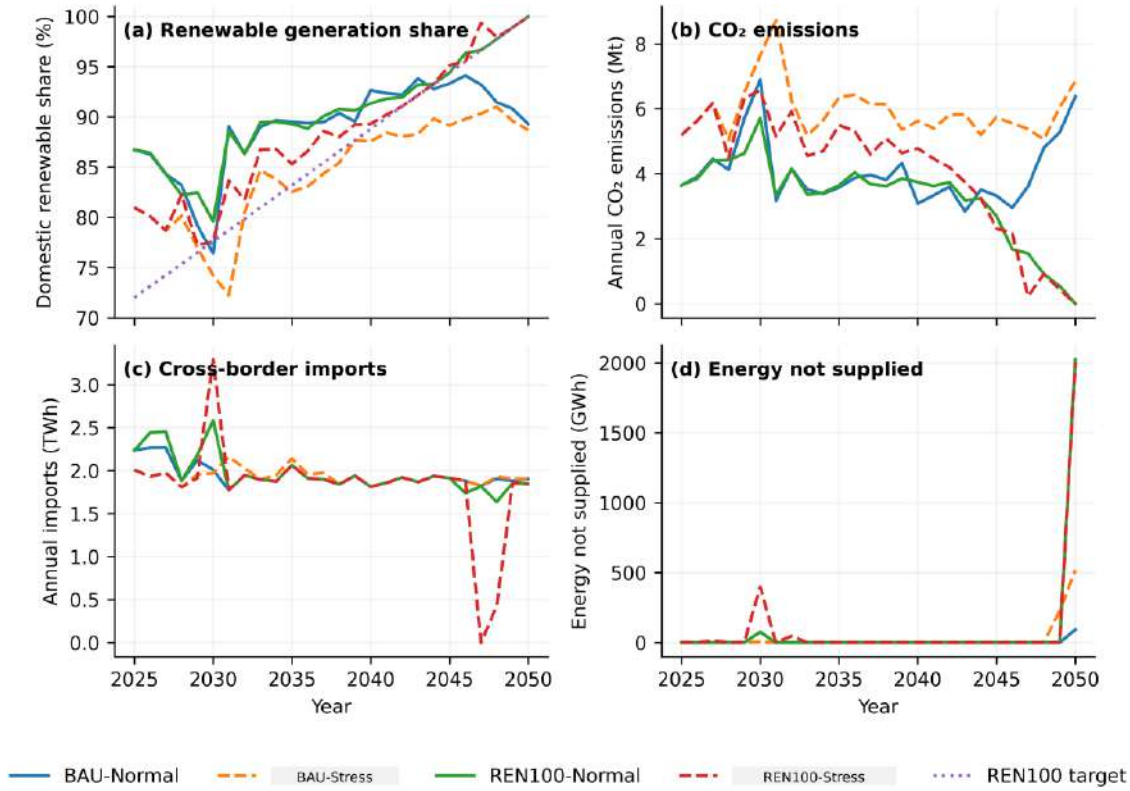

Figure 3: Transition indicators under policy and hydrological pathways, 2025-2050.

hydropower continues to dominate production. This behavior is consistent with studies of high-renewable systems in which firm and flexible resources become more valuable during periods of limited weather-dependent generation (Papaefthymiou and Dragoon, 2016; Sepulveda et al., 2018). For Ecuador, long-term expansion studies should therefore evaluate the renewable share together with an explicit adequacy criterion.

In the REN100 cases, solar, wind, geothermal, and bioenergy reach the limits represented in the analysis while hydropower remains the main domestic source and receives additional investment under stress. The available diversification margin is therefore reduced at the same time that lower water availability creates a greater need for flexibility. Resource complementarity can reduce those requirements when the portfolio contains sufficient technological diversity (Luz and Moura, 2019), and uncertainty in water availability changes the economic value of individual investments (Guerra et al., 2019). Storage, demand response, and a broader supply of firm renewable resources should consequently be quantified before defining a REN100 pathway with lower adequacy deficits.

The generation selected by the model also has to be considered together with the transmission network through which it reaches demand. Several candidate resources are located away from the main load centers, so their contribution to adequacy depends on available internal transfer capacity. New lines, corridor reinforcement, and exchanges with Colombia and Peru are represented in the formulation and participate in the system response during dry periods. The present comparison does not separate the adequacy contribution of each intervention; quantifying that contribution would be necessary to determine how much network reinforcement and greater exchange capability can reduce the shortfall near 2050.

The ENS values reported in this study correspond to monthly operation and to the technologies included in the candidate portfolio. This resolution is appropriate for long-term expansion and aggregate energy adequacy, but it does not reproduce ramping, intraday variability, or other short-duration operating constraints. Storage is also absent from the investment set, as it has not been identified as a specific investment option in official expansion plans. The reported deficits should consequently be interpreted as the performance of the portfolio under these assumptions rather than as a general result for every configuration that could reach 100% renewable domestic generation.

5. Conclusions

For the 2025–2050 horizon considered here, REN100 reduces cumulative emissions but requires higher expenditure and remains more sensitive to reduced hydropower availability than BAU. The discounted cost premium is 7.2% under normal hydrology and 9.5% under stress, while cumulative emissions decline by 19.5% and 31.4%, respectively. The resulting system includes all non-hydro renewable options available in the candidate portfolio, yet hydropower still supplies about 82% of domestic generation in 2050. The additional diversification changes the expansion mix and displaces fossil generation without removing the system's dependence on water availability.

The main limitation of REN100 appears when the renewable requirement reaches 100%, and energy not supplied approaches 2% of annual demand in both cases, despite the capacity added during the preceding decades. This outcome is obtained with the generation, transmission, and exchange options available in the analysis and therefore indicates where the decision space needs to be widened. Storage, demand response, a larger supply of firm renewable resources, transmission reinforcement, and regional exchanges should be assessed quantitatively to determine how much they can reduce the gap. For a hydro-dependent system such as Ecuador's, the long-term renewable objective is more credible when it is accompanied by an adequacy requirement that explicitly considers periods of low hydropower availability.

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Between Hydrocarbons and Electrification: Investigating Preconditions of Countries for Aligning with U.S.-China Energy Rivalry

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Abstract

This article investigates the structural preconditions behind countries' potential alignment with either the U.S. hydrocarbon-oriented energy bloc or China's electrification-oriented bloc, addressing an under-researched aspect of the formation of global geo-economic energy spheres. The objective is to identify which economies are currently preconditioned toward each pole and why. Methodologically, the study integrates resource-endowment analysis grounded in the Heckscher–Ohlin (1933) framework, comparative analysis of energy structures and governance, and geopolitical alliance architecture, jointly anchored in Stubb's (2026) triangle-of-power concept. These dimensions converge in a multi-layered analysis spanning the 50 largest energy-consuming economies across all continents, collectively accounting for approximately 90% of global energy supply. It is argued that the policy choices of a third – heterogeneous and balancing – energy bloc will prove decisive in determining which of the two competing blocs gains momentum in the near future.

The empirical analysis, based on the latest data, yields several distinctive findings. China has one fully aligned structural counterpart – India – which replicates its coal-dominated energy and electricity mix, mineral-rich endowment, hydrocarbon net-importer status, and BRICS+ institutional affiliation. Together, China and India account for 33.8% of global energy. The U.S., by contrast, has no fully comparable counterpart across all analyzed dimensions. Canada is its closest peer, sharing oil-and-gas dominance, hydrocarbon net-exporter status, mineral richness, NATO/OECD membership and market-liberal governance – yet diverges in electricity mix, where hydropower rather than gas dominates, reflecting Canada's abundant water resources. Together, the U.S. and Canada represent 16.1% of global energy. Both superpowers attract numerous partially aligned counterparts: China's partial structural peers encompass coal-dominated, mineral-rich, hydrocarbon-importing economies, while the U.S. partial counterparts are primarily hydrocarbon net-exporting, oil-and-gas-dominated economies – though most remain outside the U.S. formal institutional orbit, notably Russia, Iran, and Iraq, with Venezuela representing a further specific case. Brazil, Mexico, and Turkey appear as pivotal swing economies whose choices may prove most consequential, alongside smaller yet significant economies in this regard, such as the EU member states and Chile.

The research value added lies in demonstrating that resource endowment and the associated infrastructure path-dependence, energy structures and governance, and alliance cooperation – analyzed as a combined framework – can render insightful geoeconomic outlook. In terms of policy relevance, the study illuminates the position of a third block of balancing economies and their opportunity to leverage structural ambiguity for a deliberate middle power agency maneuver and international cooperation arrangements rather than drifting passively into dependency on either bloc's supply chains.

1. Introduction

Energy is one of the dimensions of economic rivalry between the United States and China. This energy rivalry, driven by their distinct capabilities and resource preconditions, is characterized by contrasting strategies. While the U.S. is leveraging its oil and gas reserves to enhance energy security and geopolitical leadership, China is advancing as an electrification superpower through nuclear and renewable energy technologies to mitigate dependency on energy imports and expand global influence. The contrasting dynamics of energy structure of these economies is a particularly visible immediate effect of these strategies (IEA, 2026). Such divergent pathways shape their geopolitical and economic stance, also significantly affecting global economy and international relations. Consequently, this rivalry has apparent implications on energy policy choices and energy diplomacy maneuver of other actors. Therefore it merits an in-depth analysis. Given times of turbulent geopolitics and weaponized interdependence, enhanced understanding of this competition may be of high value added for various decision and policy-makers. While the U.S. versus China energy rivalry is widely discussed, understanding of what drives individual countries to align with either the U.S. hydrocarbon-oriented bloc or China's electrification-oriented bloc appears under-researched.

While this article is only a first step to comprehensively investigate the structural preconditions of various countries for leaning towards the U.S. hydrocarbon-oriented or China's electrification-oriented energy bloc (sphere) and to understand related geoeconomic phenomena, it helps identifying which economies are currently preconditioned toward each pole and why. The general purpose of embedded research is to enhance existing body of knowledge on mechanisms

behind global energy developments, energy transition and related economic landscape shifts.

2. Methodology and Concept

Methodologically, the research combines energy and institutional economics with political economy approaches. Resource endowment, building on Heckscher–Ohlin model (Ohlin, 1933), is a key energy economics concept employed in this proposition. This is accompanied by comparative analysis of energy structures of economies commonly referred to as energy and electricity mix, as well as by comparative analysis of institutional setting (governance) of energy systems across countries. The insights from these perspectives are also supplemented by the existing interdependencies arising from geopolitical alliances and economic integration groupings. This multilayer analytical framework is conceptually anchored in a triangle-of-power concept by Stubb (2026), adding a realism-driven layer of global economic and geopolitical interdependences onto standard energy economics considerations. This proposed conceptual framework depicted in Figure 1 serves for an empirical comparative investigation which is to answer the research question – which economies are currently preconditioned to aligning with the U.S. hydrocarbon block, which ones are more inclined to align with China-led electrification block, and which ones may be balancing in this strategic geoeconomic choice.

The analysis covers 50 largest energy-consuming economies across all continents, collectively accounting for approximately 90% of global energy supply (set of countries, their country codes and the shares of their total energy supply are presented in Figure 4) and is based on latest available snapshot data.

The concept of triangle of power (Stubb, 2026) posits a multipolar world organized around three primary poles – the Global West, the Global East, and the Global South. At the center is the escalating competition between the U.S. and China, as both try to forge bilateral deals and regional alliances, but it is the Global South that will ultimately determine whether the future tilts toward cooperation or fragmentation – depending on whether and which of the two superpowers can build alliances and structural dependencies to expand its sphere of influence especially towards the Global South economies. The emerging energy bloc rivalry (U.S. hydrocarbon-oriented versus China electrification-oriented) represents distinct but conceptually alike structural reorganization. Stubb's framework is used to argue that power in the shifting world order derives from creating functional blocks (spheres) – forcing other states into dependencies that make alternative alignments costly. The energy bloc alignment mechanism is part of this structural shift: countries align not from ideological preference but because the bloc's technological, financial, and institutional infrastructure creates lowest-friction pathways for their own security and development objectives. The choices of largest balancing economies in particular may be decisive in determining which of the two competing energy blocs, ergo which of the two economic superpowers, gains momentum in the near future.

3. Global Energy Outlook between Hydrocarbons and Electrification

The research presents a multi-layered framework for analyzing structural preconditions and differences for countries in terms of their position within the global energy transition and the broader U.S.–China strategic rivalry that emanates through competing hydrocarbon and electrification blocks (spheres of influence).

3.1. Energy Resource Endowment

Resource endowment may be regarded as a structural constraint. The resource curse literature (Sachs & Warner, 1995; Auty, 2001) demonstrates that countries' economic development trajectories are substantially shaped by natural resource endowments. This proposition extends that view as energy alignment follows a rational optimization under resource constraints, where countries attempt to maximize returns from

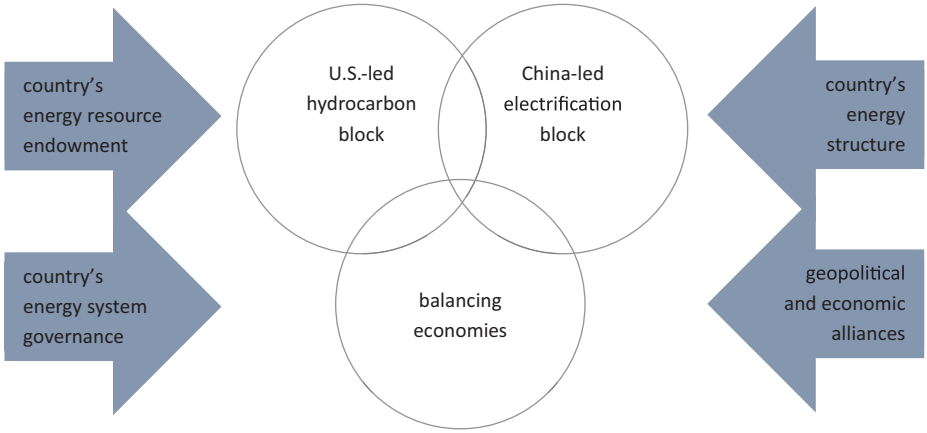

Figure 1: Conceptual framework for geoeconomic segmentation of countries alignment to US-China energy rivalry
Source: Author's elaboration based on Stubb (2026) concept.

their particular resources while minimizing structural obsolescence risk that would hinder development. The stranded assets literature provides extensive economic basis for understanding hydrocarbon producer alignment. McGlade & Ekins (2015) assess that a policy-making agreement to limit global temperature rise below 2°C climate scenario – the backbone of Paris Agreement, implies that approximately one third of proven oil reserves, half of natural gas reserves, and around 80% of coal reserves must remain unextracted. Subsequent analysis by Welsby et al. (2021) confirms these estimates, finding that even under an optimistic assumption set about technology and policy, 90% of coal reserves, 50% of gas reserves, and 33% of oil reserves become 'unburnable' under 1.5°C pathways. Davis & Shearer (2014) demonstrate in their analysis of the 'global coal pipeline' that coal plant economics create 30-50 year operational commitments once constructed, creating fundamental misalignment with decarbonization trajectories. These plants become stranded assets – infrastructure requiring either continued operation (which may be politically costly and economically irrational) or premature retirement (which may impose write-off costs and induce social dislocation and unrest). Therefore, for hydrocarbon-abundant countries, the U.S. hydrocarbon bloc may offer asset value preservation through technological updates, continued investment in extraction, processing, and distribution technology maintenance, leading to extension of profitable extraction periods. Moreover strategic alliance with U.S. may provide protection against unilateral climate sanctions and regulatory pressure (Lockwood, 2013).

While hydrocarbon abundance may be a lock-in curse, the mineral requirements for energy transition are also posing risk to many countries. IEA (2021a) demonstrates that a 50% EV penetration scenario requires extensive increase in critical minerals' production, i.e. a 42-fold increase in lithium production, 25-fold increase in cobalt production, and 21-fold increase in nickel production. Beyond production quantities, the value chain integration is critical. Notter et al. (2021) analyze the lifecycle emissions of lithium-ion batteries, demonstrating that processing and cathode manufacturing represent 20-30% of lifecycle environmental impact. Optimizing these stages requires geographic and technological integration unavailable in fragmented supply chains. China's vertical integration – from lithium extraction, through battery integration, to EV assembly and grid integration – creates network externalities and coordination benefits (Hensley et al., 2016). For mineral-rich countries, the China electrification bloc offers potential technology transfer (via joint ventures and technology sharing), value chain integration (through downstream processing, manufacturing, and distribution, ultimately reducing transaction costs of such alignment), as well as aggregation with large-base demand (due to a massive consumer base from Chinese population and aligned markets that jointly creates a guaranteed demand for extracted minerals). Nevertheless such alignment towards electrification, including electromobility, is not straightforward as substitution elasticity between electricity and fossil fuels varies across sectors and time horizons. Pesaran (2007) provides econometric evidence that transport sector shows highest short-term substitution elasticity to electricity prices, while industrial process heat shows lowest elasticity. This creates differential alignment incentives – countries seeking transport electrification and energy independence are likely to gravitate toward electrification bloc logic, while countries dependent on fossil process heat might be willing to maintain a hydrocarbon orientation.

In overall, 21 of the 50 analyzed economies may be qualified as net hydrocarbon exporters – jointly covering 35.6% of total energy supply globally, while the remaining 29 as net hydrocarbon importers – altogether representing 54.2% of total energy supply globally (cf. Figure 2).

The U.S. has recently consolidated its position as a net energy exporter, led by LNG exports. Among other net hydrocarbon exporters in analyzed countries, Saudi Arabia, Iraq, and Kuwait are the most oil-dominant, with oil constituting over half of their total energy supply and exports remaining overwhelmingly crude-based. Russia is the dominant gas exporter (apart from LNG), with natural gas accounting for approximately half of its primary energy supply, alongside significant oil and coal exports. Qatar and Turkmenistan are also among gas-dominant exporters, with gas visibly accounting for over half of their respective energy supplies. Australia is a leading exporter of both coal and LNG and remains the world's largest coal exporter by value, while Indonesia is the world's largest coal exporter by volume. Colombia and Algeria are significant mid-tier exporters of oil and gas respectively. Among net importers, China and India stand out as the most consequential – China is the world's largest oil importer, while India is the world's second-largest coal importer and third-largest oil importer. Japan and South Korea remain highly dependent on imports across oil, natural gas and coal. As for European economies in the analyzed sample, they are net hydrocarbon importers, fully dependent on external supply across oil and gas and, in several cases, coal (Energy Institute, 2026; IEA, 2026a; IEA, 2026b; IEA, 2026c).

Furthermore, 24 of the 50 analyzed economies may be qualified as mineral-rich for energy transition megatrend – jointly covering 68% of total energy supply globally, while the remaining 26 as mineral-scarce or mineral-limited countries – altogether representing 21.8% of total energy supply globally (cf. Figure 3). Interestingly, both – the U.S. and China may be segmented into the same mineral-rich category, although China possess more leverage in terms of supply chains, especially when batteries are concerned.

In analyzed countries mineral endowments are highly concentrated geographically. Chile holds the world's largest reserves of copper (almost one-fifth of global total) and also leads on lithium reserves alongside measured and indicated reserves of Argentina, Australia, and Bolivia – the latter beyond the Top 50 scope

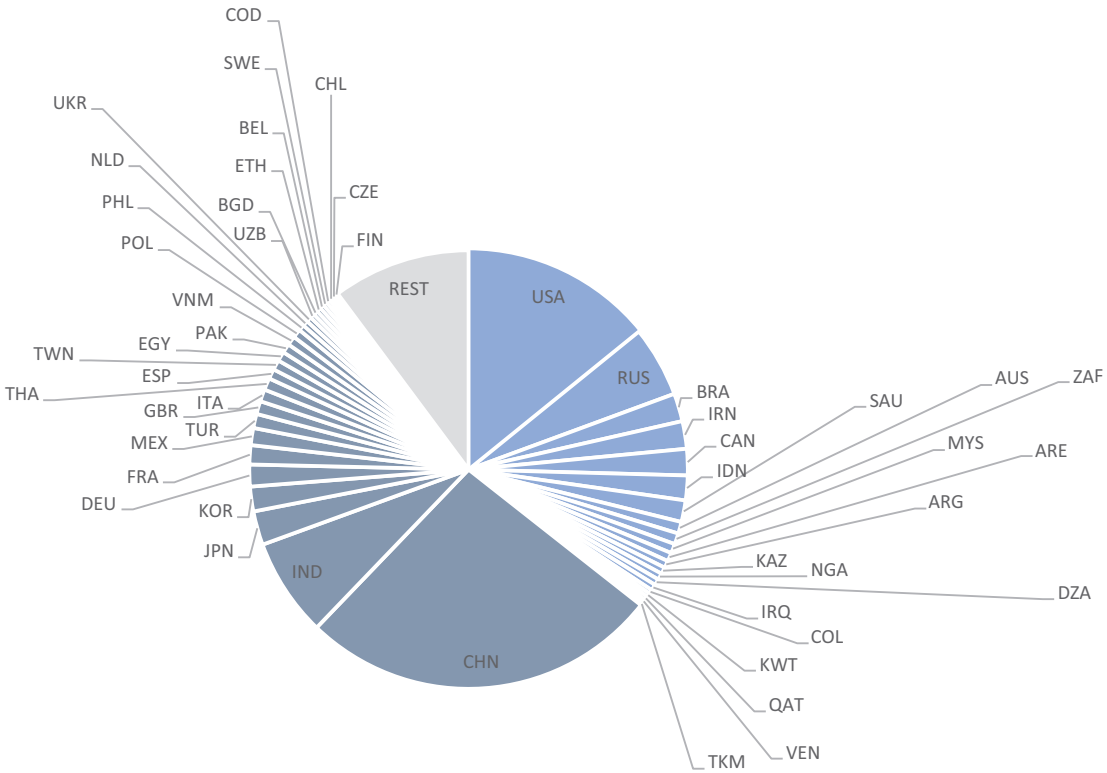

Figure 2: High-level segmentation of Top 50 countries in terms of total energy supply (TES) – light blue for hydrocarbon net exporters (35.6% TES), dark blue for hydrocarbon net importers (54.2% TES) based on latest available data
Source: Author's elaboration based on data from Energy Institute (2026), UN Comtrade (2026) as well as data and information from IEA, EIA, and OPEC.

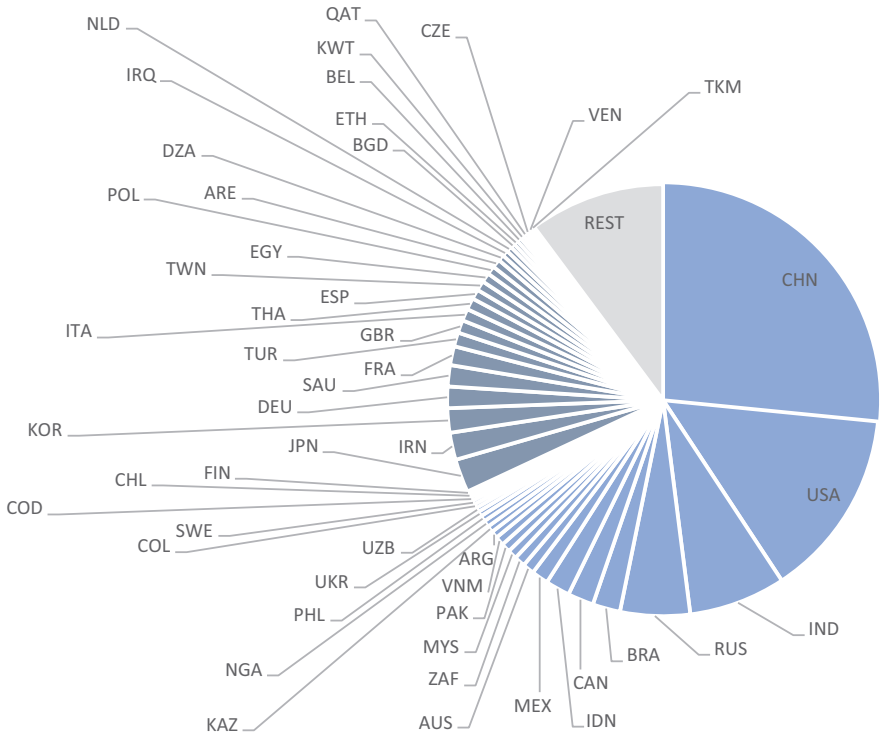

Figure 3: High-level segmentation of Top 50 countries in terms of total energy supply (TES) – light blue for mineral-rich economies (68.0% TES), dark blue for mineral-scarce or mineral-limited economies (21.8% TES) based on latest available data
Source: Author's elaboration based on data from USGS (2026) and IEA (2025).

but part of so called Lithium Triangle, all possessing exceptionally large lithium resources. The DR Congo prevails in cobalt, holding around half of world reserves and accounting for almost three-quarters of global cobalt mine output as of 2025. Indonesia dominates nickel (almost half of world reserves) and has rapidly grown its cobalt position. Australia ranks among the top producers and reserve holders for lithium, cobalt, and nickel simultaneously. China leads the rare earth element reserves (around half of global total) and dominates processing of virtually all battery metals, refining most of lithium, cobalt, and rare earths globally. Brazil is among the largest rare earth element reserves alongside China and Vietnam. Among the mineral-scarce economies, Japan, South Korea, Taiwan, and most European states – Germany, France, Italy, Spain, Belgium, the Netherlands, and Czechia – hold no or limited reserves of any key transition mineral (commercially-wise), making them structurally dependent on imports across the entire battery metals supply chain. The notable exceptions are Sweden – boasting one of Europe's largest rare earth deposits alongside Norway (the latter beyond the Top 50 scope), and Finland – which hosts one of Europe's most advanced battery-minerals ecosystems with nickel and cobalt extraction and processing, and lithium mining (USGS, 2026; IEA, 2025).

3.2. Energy Structure and Governance

Regardless of country positioning in terms of energy resource endowment, economies across continents are inherently different energy-structure-wise. While the global economy is mostly reliant on oil (economy-wide energy mix in primary energy notion), the electricity generation structures vary across countries. The U.S. relies on oil and natural gas when total energy mix is concerned, and on natural gas when electricity generation is concerned (electricity mix). While China's energy mix is dominated by coal, likewise its electricity mix that is also overwhelmingly dominated by coal. Interestingly, while most of 50 economies in scope share their electricity profiles with either of the two superpowers, most of the analyzed EU member states as well as the ex-EU-member – the U.K., show different electricity profiles than those of U.S. or China (cf. Figure 4).

David (1985) and Arthur (1989) established the theoretical foundation claiming that increasing returns and positive feedback loops create path dependence in technology selection, making early choices disproportionately influential in determining equilibrium outcomes. Energy systems exhibit this dynamic with particular intensity also because of geographic network effects (Lund & Mathiesen, 2009) where grid architecture optimized for particular generation mix creates physical infrastructure which is difficult to repurpose. Therefore, once countries commit to energy infrastructure (across various segments), switching costs become excessive. Early-mover advantage in establishing technological standards creates lasting advantages. Capital availability is critically important factor in this regard. China's patient capital (Geng et al, 2026) and state-directed financing suits long-gestation infrastructure, while private Western capital requires faster returns. This creates natural alignment preconditions that may be independent of pure current political preference.

Institutions are instructive on how energy systems function and how their governance affects potential for alignment to either of the analyzed energy spheres. The market-dominant regimes, characterized by liberalized energy markets driven by price signals and risk-return expectations, independent regulators, and investor-owned utilities, may be attractive for the hydrocarbon model. Private capital funding infrastructure drives efficiency and fosters competition on cost reduction. Countries with established market-liberal regulatory systems also face higher switching costs to Chinese-led electrification model with embedded subsidies and required reskilling. Workers trained in coal mining, oil refining, conventional grid operation have specialized human capital with limited transferability. Acemoglu et al. (2016) demonstrate that occupational specialization reduces worker adaptability to technological transition, creating constituency resistance to infrastructure change independent of physical switching costs. On the other hand, state-directed regimes with dominance of state-owned enterprises and embedded central planning may be more prone to prospective yet nascent and capital intense electrification model. Such governance enables state coordination of massive infrastructure investment, as well as its moderating role in technology bundling and development finance deployment which is holistically aligned with national strategies.

Throughout analyzed countries, minority represents advanced market economies characterized by predominantly market-based energy governance, with liberalized or near-liberalized energy markets and generally limited direct state control over investment and operational decisions. These are 15 countries – U.S., Japan, Canada, U.K., Australia, and the EU member states at scope of the analysis, i.e. Germany, France, Italy, Spain, Poland, Netherlands, Belgium, Sweden, Czechia and Finland, representing altogether 27.2% of total energy supply globally. The majority of analyzed countries showcase less market-oriented energy governance and visible direct or indirect state control over their energy systems and decision-making (35 countries representing 62.6% of total energy supply globally).

3.3. Energy and Non-Energy Alliance Cooperation

Neorealist research holds that alliances like NATO function as balancing coalitions – members pool capabilities against a perceived threat, accept binding mutual-defense commitments, and in turn lose some freedom of independent action (Walt, 1987). This produces the 'alliance security dilemma' where members must balance the risk of abandonment against the risk of entrapment in a partner's conflicts (Snyder, 1984). Hence, security alliances both constrain and enable military and related choices, including energy which is regarded as a matter of national security (energy securitization). Whereas formal economic groupings reshape domestic policy through strategic institutional

Country	% of global	Dominant energy mix source			Dominant electricity mix source				
		oil-gas	coal	other	gas	coal	hydro	solar-wind	nuclear
China (CHN)	26,6%		✓			✓			
U.S. (USA)	14,2%	✓			✓				
India (IND)	7,3%		✓			✓			
Russia (RUS)	5,2%	✓			✓				
Japan (JPN)	2,5%	✓			✓				
Brazil (BRA)	2,1%	✓					✓		
Iran (IRN)	2,0%	✓			✓				
Canada (CAN)	1,9%	✓					✓		
Indonesia (IDN)	1,8%	✓				✓			
South Korea (KOR)	1,8%	✓				✓			
Germany (DEU)	1,6%	✓						✓	
Saudi Arabia (SAU)	1,6%	✓			✓				
France (FRA)	1,4%			✓					✓
Mexico (MEX)	1,3%	✓			✓				
Turkey (TUR)	1,0%	✓				✓			
U.K. (GBR)	1,0%	✓						✓	
Italy (ITA)	0,9%	✓			✓				
Thailand (THA)	0,9%	✓			✓				
Australia (AUS)	0,9%	✓				✓			
South Africa (ZAF)	0,8%		✓			✓			
Spain (ESP)	0,7%	✓						✓	
Taiwan (TWN)	0,7%	✓			✓				
Egypt (EGY)	0,7%	✓			✓				
Malaysia (MYS)	0,7%	✓				✓			
Pakistan (PAK)	0,7%	✓					✓		
Vietnam (VNM)	0,7%	✓				✓			
Poland (POL)	0,6%		✓			✓			
U.A.E. (ARE)	0,6%	✓			✓				
Argentina (ARG)	0,5%	✓			✓				
Kazakhstan (KAZ)	0,5%		✓			✓			
Nigeria (NGA)	0,5%	✓			✓				
Algeria (DZA)	0,5%	✓			✓				
Iraq (IRQ)	0,4%	✓			✓				
Philippines (PHL)	0,4%	✓				✓			
Netherlands (NLD)	0,4%	✓						✓	
Ukraine (UKR)	0,4%		✓						✓
Uzbekistan (UZB)	0,3%	✓			✓				
Bangladesh (BGD)	0,3%	✓			✓				
Ethiopia (ETH)	0,3%			✓			✓		
Belgium (BEL)	0,3%	✓							✓
Colombia (COL)	0,3%	✓					✓		
Sweden (SWE)	0,3%			✓			✓		
Kuwait (KWT)	0,3%	✓			✓				
Qatar (QAT)	0,3%	✓			✓				
DR Congo (COD)	0,3%			✓			✓		
Chile (CHL)	0,3%	✓						✓	
Czechia (CZE)	0,3%		✓						✓
Venezuela (VEN)	0,2%	✓					✓		
Turkmenistan (TKM)	0,2%	✓			✓				
Finland (FIN)	0,2%			✓					✓

Figure 4: Top 50 countries in terms of total energy supply (TES) – dominant energy mix source and dominant electricity mix source based on latest available data
Source: Author's elaboration based on data from Energy Institute (2026) and information from IEA.

anchoring. The EU membership is the clearest case, where EU rules reach into domestic regulatory, fiscal, and even social policy, producing convergence pressures independent of national preferences (Börzel & Risse, 2003). This goes beyond simple bargaining at the phase of accession since continued membership requires adopting the *acquis communautaire*, which constrains future policy autonomy in ways that persist even when a government would prefer otherwise. This is especially valid for economic policy aspects that have been delegated to supranational governance level. While energy policy of the EU member states is mandated to national governments, the EU-wide climate policy strongly interferes and constraints the energy trilemma maneuver. The internal energy market of the EU is also decisive in this regard.

Within the energy landscape, OPEC stands out as a key grouping shaping how supply is governed on the world's largest energy commodity market. Functioning as a crude oil cartel, OPEC coordinates member behavior around price and output rather than security concerns. Its logic fits directly within cartel theory: members confront a collective-action problem in which coordinated production cuts raise revenue for the group as a whole, yet each member retains an individual incentive to cheat on agreed quotas. Empirical evidence bears this out – actual compliance with OPEC quotas tends to be weak, suggesting the 'alliance' shapes rhetoric and bargaining leverage more reliably than it shapes actual output (Colgan, 2014). Formal alliance commitments, more broadly, are understood as costly signals, since reneging on them carries reputational costs. Alliance membership accordingly narrows the range of acceptable foreign and economic policy choices – spanning voting behavior at the UN, alignment on trade policy, and participation in sanctions regimes. The empirical literature on UN voting patterns (e.g. Voeten, 2000) finds that NATO and EU members cluster far more tightly together than non-aligned states of comparable economic size, indicating that alliance membership exerts a measurable, independent effect on revealed foreign policy preferences – not merely a rhetorical one.

The analyzed countries span major international alliances (organizations), reflecting deep geopolitical segmentation. The Western institutional bloc is anchored by the EU, NATO (covering the U.S., Canada, U.K., most EU member states and Turkey), the OECD (adding Japan, South Korea, Australia, Chile, Colombia, and Mexico), and the IEA (overlapping largely with the OECD). The U.S. sits at the apex of this Western architecture, holding simultaneous membership in NATO, the OECD, and the IEA while remaining outside BRICS, OPEC+, and every regional bloc. Against this, the BRICS+ bloc has expanded significantly – its full members among the analyzed countries include China, Russia, India, Brazil, South Africa, Egypt, Ethiopia, Iran, U.A.E, Indonesia, and Saudi Arabia. China, uniquely, combines BRICS full membership with permanent UN Security Council status and deep bilateral energy and trade dependencies across ASEAN, GCC, and African member states – while remaining outside NATO, the OECD, and the IEA, positioning it as the institutional counterweight to the U.S. across virtually every dimension of the analyzed group. The OPEC+ ties together a distinct hydrocarbon-exporting coalition – Saudi Arabia, Iraq, Kuwait, U.A.E, Algeria, Nigeria, and Venezuela as OPEC members, with Russia and Kazakhstan as the pivotal non-OPEC participants. The GCC (Saudi Arabia, U.A.E, Kuwait, Qatar) and ASEAN (Indonesia, Malaysia, Thailand, Vietnam, Philippines) constitute sub-regional groupings with strong energy and trade dimensions, while Mercosur links Brazil, Argentina, and – as associate member – Chile. Notably, several countries straddle blocs: Turkey is a NATO member and BRICS candidate; India and Brazil maintain active Western partnerships while deepening BRICS engagement; and the U.A.E participates simultaneously in GCC, OPEC, and BRICS, a somewhat multipolar hedging strategy.

4. Policy Implications and Conclusion

China has one fully aligned counterpart to its structural energy preconditions – India – a coal-dominated and mineral-rich economy, with hydrocarbon net-importer status and BRICS+ institutional affiliation. Together, China and India account for 33.8% of global energy. For the U.S., Canada is its closest peer, sharing oil-and-gas dominance over energy mix, hydrocarbon net-exports, mineral richness, NATO/OECD anchor and market-liberal governance – yet diverges in electricity mix, where hydropower rather than gas dominates. Together, the U.S. and Canada represent 16.1% of global energy. Resource-rich hydrocarbon producers (21 countries with 35.6% of global energy supply) are structurally – though not institutionally – closest to the U.S. model, sharing its stranded-asset exposure and extraction-dependent economic logic, yet most remain outside the NATO/OECD alliances and formal U.S. influence (like Russia or Iran), meaning their alignment is material rather than institutional. Mineral-rich, hydrocarbon-scarce economies (12 countries with 38.6% of global energy supply) presumably have the strongest pull toward China's electrification bloc. The largest group of analyzed economies – predominantly EU and OECD members – shows no decisive structural lean toward either pole, instead occupying a contested middle ground where institutional (Western) and material (Chinese supply-chain) pressures pull in opposite directions. Turkey emerges as an interesting case since despite its NATO and OECD anchoring the country demonstrates that institutional alliances do not preclude deep material alignment with the rival China-led energy bloc (Fabian, 2025). Turkey together with Brazil and Mexico appear as key balancing economies whose choices may prove most consequential, alongside smaller yet significant economies in this regard, such as the EU member states and Chile.

For such balancing economies, given Stubb's (2026) triangulation framework, these states should treat ambiguity as a bargaining asset rather than resolve it prematurely – extracting concessions from both

blocs while infrastructure and supply-chain dependencies are still negotiable. Policymakers should treat this as requiring deliberate 'middle power agency' – diversifying renewable-equipment sourcing, as well as developing battery and critical-minerals processing capacity domestically or via allied supply chains, rather than allowing institutional alignment and material dependency to drift further apart. As for mineral-rich peripheral economies, the apparent opportunity of China's demand aggregation carries severe risk of replicating resource-curse dynamics in a new form – structural lock-in via downstream processing dependency. These states should prioritize negotiating domestic value-addition rights (as Turkey has attempted with its rare-earth reserves) rather than accepting raw-export terms, since processing capacity, not extraction rights, determines long-run bargaining power. For hydrocarbon-abundant states, the U.S.-led sphere offers value protection against stranded-asset risk but is time-limited rather than permanent, since global electrification demand growth structurally and erodes the bloc's relevance regardless of alliance commitments. Diversification toward mineral processing or renewable manufacturing at scale – even from a hydrocarbon base – should be treated as a hedging strategy, not a competing alignment choice.

The U.S. versus China energy alignment represents a nested game theory problem (Tsebelis, 1990) to other countries – they select not only an energy technology but entire economic-strategic ecosystem whose components exhibit complementarities and strategic interdependencies, all representing a long-lasting process. In this context Geels' (2002) multi-level perspective on technological transitions demonstrates that energy systems are not merely technological configurations but embedded socio-technical systems comprising infrastructure, organizations as well as institutions (property right regimes, regulatory frameworks, technical standards) and behaviors (operational procedures, investment decision rules, user behaviors). Hence, this research is suggestive in that energy system governance and infrastructure choices become self-reinforcing, where switching costs, specialized labor, and grid architecture render early technology choices disproportionately influential over time. This effect may be of particular significance when discussed energy alignment is concerned. The article also underscores the role of capital structure – China's 'patient', state-directed capital suits long-horizon infrastructure deployment, while Western private capital tends to demand faster returns.

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Keeping the Lights On: Transition Priorities and Economic Returns for Cuba's Power Sector

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Abstract

Cuba's power sector has collapsed to the point of threatening the country's political and economic stability: blackouts of 12–20 hours per day are now common, driven by the decline of Venezuelan fuel support and decades of deferred maintenance on seven aging liquid-fuel plants. This paper develops an identification-level economic and financial assessment of a five-pillar transition program — legal and regulatory reform, emergency floating generation, distribution company (DISTCO) restructuring, targeted social protection, and long-term combined-cycle gas turbine (CCGT) generation — designed to be implementable in parallel rather than sequentially. The analysis is conditional on a political transition and on repeal or suspension of the Helms-Burton provisions, together with Cuban accession to the international financial institutions; it estimates what the program would be worth under those conditions rather than forecasting when they arrive.

Using a data set initially assembled through field interviews with emigrated utility engineers and triangulated against tanker-tracking and official statistics, the paper estimates an economic IRR of 24 percent for DISTCO loss-reduction contracts and 19 percent for a four-unit combined-cycle program replacing the seven large liquid-fuel plants, rising to 21 percent once the avoided cost of re-chartering emergency capacity is counted. Benefits are estimated on the two margins conventional in power sector appraisal: the resource cost saved by displacing existing generation, and willingness to pay for the incremental supply that rationing currently suppresses. Because the legacy fleet's capital is sunk, displacement is valued at its avoidable cost of roughly $162/MWh rather than its full levelized cost of approximately $328/MWh; the proposed plants generate at $104/MWh, and the fleet-wide average LCOE, blending in existing solar and the ENERGAS CCGT capacity, falls to approximately $245/MWh by 2029. Total program cost is estimated at $7.3 billion (2026 prices), of which $2.8 billion would require donor grant financing. At the proposed cost-recovery tariff, the combined-cycle program returns a financial IRR of 25 percent. The largest return in the program, however, is not the generation investment but the emergency bridge: each dollar of premium paid to deliver capacity five years early avoids twelve to thirty dollars of blackout cost, against estimates placing the annual cost of blackouts at $6–15 billion. The paper argues that financial, not economic, viability is the binding constraint, given the share of the population unable to pay cost-recovery tariffs during the first years of a transition, and proposes a means-tested lifeline tariff as the financing bridge.

Keywords

Cuba, power sector reform, electricity transition, combined-cycle gas turbines, distribution utility restructuring, post-conflict infrastructure finance

JEL Codes

Q41, Q48, L94, O54

1. Introduction

The US government should be actively planning today for the support of the power sector during a future political and economic transition in Cuba. This paper identifies a set of measures that could be implemented rapidly to improve sector performance and estimates their economic and financial returns. The power sector is the Achilles heel of Cuba's economic and political stability: absent serious reform, a transition will face heavy obstacles or fail outright.

The sector's decline has been steady, but 2025 and 2026 have been by far the most severe years on record. The systemic collapse of the Unión Eléctrica (UNE) grid — driven by the decline in Venezuelan fuel support and decades of underinvestment in maintenance — has produced blackouts that have sharply reduced economic activity and fueled political unrest, including the largest street protests since 1994. An estimated 25 percent of the population has emigrated since 2020, a migration pressure with direct implications for US regional security interests given Cuba's proximity — roughly 90 miles — to Florida.

Restoring the Cuban grid is accordingly a US national security interest as well as a Cuban economic one. This paper proposes a transition fueled substantially by US liquefied natural gas (LNG) exports: an arrangement that offers a new market for US LNG exporters, contracts for American engineering and management firms, and a vehicle for multilateral development bank (MDB) guarantees to crowd in private capital rather than requiring direct appropriations. Replacing the seven large liquid-fuel plants would reduce the levelized cost of energy (LCOE) to a competitive $143–177/MWh during an emergency-generation phase, falling further to $104/MWh once land-based combined-cycle gas turbines (CCGTs) are operational.

The remainder of the paper proceeds as follows. Section 2 situates the analysis within the power sector reform literature. Section 3 describes the current structure of the Cuban power sector and the data assembled to analyze it. Section 4 sets out the five-pillar reform program and its component costs. Section 5 presents the economic and financial results. Section 6 discusses sequencing, risk, and directions for further

study. Section 7 addresses the specific entry points for US and multilateral engagement, and Section 8 concludes.

Two conditions frame everything that follows. The analysis assumes a political transition in Cuba and the repeal or suspension of the Helms-Burton provisions and the associated embargo restrictions, together with Cuban accession to the International Monetary Fund, the World Bank, and the Inter-American Development Bank. These conditions are load-bearing rather than incidental. They govern access to US liquefied natural gas and to generating equipment and spare parts; the availability of multilateral guarantees and of the concessional finance whose value, measured against commercial terms, is worth roughly ten percentage points of equity return in Section 5; and the ability of US-domiciled sponsors to bid into the competitive tenders proposed throughout. The paper does not forecast whether or when these conditions will be met. It estimates what a power sector program would be worth if they were, which is why implementation is expressed as elapsed duration from a transition rather than in calendar years, and why Section 7 separates preparatory work that can proceed under present conditions from capital commitments that cannot.

2. Related Literature

This paper sits within a well-established literature on power sector reform in developing and transition economies. Bacon (2018) reviews three decades of World Bank-supported utility reform and finds that outcomes depend less on the specific ownership model chosen (full privatization, concession, or management contract) than on the sequencing of institutional reform relative to private participation — independent regulation and corporatization first, competitive or private operation second. Foster and Rana (2020), synthesizing twenty-five years of reform experience across fifteen developing countries, add a caution directly relevant to Cuba's case: only a handful of developing countries ever implemented the full 1990s template of restructuring, independent regulation, private participation, and competitive markets, and the common outcome is a hybrid in which market orientation coexists with continued state dominance. Their finding is not that the template is wrong but that partial, sequenced adoption is the norm and should be planned for rather than treated as failure, and their central recommendation follows: a two-track approach in which countries in more challenging environments concentrate first on governance reform and financial viability while more ambitious structural reforms are deferred. That is the sequence proposed in Section 4. They also find that while most utilities studied achieved operating cost recovery, few reached full cost recovery — the gap that the social protection bridge in Section 4.4 is designed to make politically survivable.

The Inter-American Development Bank's regional energy framework (IDB 2019) documents the Latin American and Caribbean experience most directly relevant here, including the Chilean, Argentine, and Peruvian reforms that anchor the regulatory recommendations in Section 3.1 below. Alvarado de Córdoba and Belt (2018) describe the successful case of power sector reform in Guatemala, a relatively small power market in a country with similar per capita GDP as Cuba. That study's emphasis is competitive procurement for generation and transmission, and it argues that the lessons of markets at this scale extend to a wide range of countries in sub-Saharan Africa, Asia, and the Middle East and North Africa — a transferability claim that bears directly on the question, addressed in Section 3, of whether Cuba's system is large enough to sustain competitive market design. The benefit framework applied in Section 5 follows the Asian Development Bank's appraisal guidance (ADB 2013), which values displaced output at the resource cost saved and incremental output at willingness to pay.

This paper's contribution to that literature is threefold: it applies the sequencing and social-protection lessons of the reform literature to a case — a centrally planned, vertically integrated monopoly emerging from acute fiscal and fuel-supply collapse — that differs materially from the middle-income, partially liberalized economies more commonly studied; it extends the MARKAL-TIMES least-cost expansion modeling of Wright, Belt, et al. (2010) with updated technology assumptions (FSRU-based LNG import, grid-scale solar PV) that were not commercially viable when that analysis was conducted; and it assembles an original operational data set for a utility that does not publish reliable statistics, using a triangulation method described in Section 3.2.

3. Cuba's Power Sector Today

UNE, under the Ministry of Basic Industries, is a vertically and horizontally integrated state monopoly managing generation, transmission, and distribution, with one partial exception: ENERGAS S.A., a joint venture among CUPET (the state oil company), UNE, and Sherritt International (Canada), which operates two CCGT plants at Varadero and Boca de Jaruco with a combined 506 MW of capacity — about 10 percent of national installed capacity. As of early 2026, ENERGAS remains the island's most reliable and lowest-carbon generation source and continues to provide frequency-control services that help stabilize the national grid. ENERGAS is instructive for reform design in two respects: it demonstrates that a joint-venture generation structure can operate reliably within an otherwise dysfunctional sector, and its associated-gas fuel supply — sourced domestically rather than imported — illustrates the LCOE advantage of gas-fired generation even before the LNG-import infrastructure proposed in Section 4.5 is in place. Whether Cuba's system is large enough to sustain a competitive wholesale market is less settled than is often assumed. Foster and Rana (2020) set the notional thresholds at five generating companies, each at a minimum efficient scale of 400–1,000 MW for thermal plant, implying a system of at least 3 GW of peak demand or 20 TWh of annual energy. Cuba is marginal on both tests: peak demand is near 3 GW and annual

generation reaches roughly 18.6 TWh only after the investments proposed here. More binding still is the number of independent generators. Once the legacy fleet retires, competition at the system peak would rest on ENERGAS and the new combined-cycle capacity alone, since solar without storage does not compete at the evening peak — which is the principal reason the generation program in Section 4.5 is specified as four units rather than two. The conclusion is not that competition is unattainable, but that Cuba should aim first at competition for the market, through auctions, rather than competition in it, through a spot exchange. Consistent with earlier work (Belt 2010), reaching the latter stage credibly takes three to five years even under favorable conditions, and the immediate priority must be stabilization and DISTCO reform rather than market design.

The remaining generation fleet consists of seven large, aging liquid-fuel plants running well below design efficiency. Estimates of technical and non-technical distribution losses vary by source — the World Bank's global database places Cuban losses at 22 percent, while UNE's own figures suggest 18 percent — and this paper uses 20 percent as a working estimate. Because penalties for power theft in Cuba are severe, these losses are understood to be almost entirely technical rather than commercial in nature.

4. A Five-Pillar Reform Program

Cuba's power sector is trapped in a self-reinforcing vicious circle: blackouts reduce economic activity and fiscal revenue, leaving less funding for fuel and maintenance, which worsens the blackouts, which accelerates emigration and deters investment, which further erodes the fiscal base. Breaking this circle requires simultaneous action across five fronts, implemented in parallel rather than sequentially, since each reinforces the others.

4.1 Legal and Regulatory Framework ($20 million)

Chile, Argentina, and Peru pioneered power sector reform toward competition and private investment in Latin America, and most of the region followed; those experiences — adapted, not imported wholesale — offer the most relevant lessons for Cuba. Priority actions include developing a sector strategy, drafting laws and regulations to promote competition and private participation, corporatizing and unbundling UNE into 6–8 successor entities (a generation company, a transmission company, a dispatch center, and three DISTCOs), and establishing an independent Public Utility Commission (PUC).

Competitive procurement deserves particular emphasis among these actions, because it has the most consistent empirical record of any single reform in this list and is the one most often abandoned under time pressure. Maurer and Barroso (2011) set out the underlying case: auctions substitute market-driven price discovery for the administrative determination of prudent costs that bilateral negotiation requires — determination new regulatory institutions are least equipped to make, and the point at which they are most exposed to capture. The subsequent evidence runs in one direction. Eberhard et al. (2016), reviewing two decades of independent power projects across Sub-Saharan Africa, find that competitive procurement delivers lower prices and greater transparency than either directly negotiated contracts or administratively set feed-in tariffs. Dobrotkova, Surana, and Audinet (2018), comparing utility-scale solar auctions across developing countries, document single-digit cent-per-kWh outcomes under competitive tender against markedly higher prices where capacity was procured bilaterally. Foster and Rana (2020) put it more sharply still: the adoption of competitive bidding for new generation is among the planning and procurement features most closely associated with good outcomes for security of supply, while direct negotiation of independent power projects jeopardizes value for money and invites allegations of corruption. It is also the reform that travels — independent regulation and private generation through IPPs were the two most widely adopted elements of the 1990s package, taken up by more than seventy percent of developing countries, while the rest of the model spread far less. Alvarado de Córdoba and Belt (2018) document the Central American application in markets of roughly Cuba's scale. This evidence supports three specific recommendations here: that the DISTCO operating contracts in Section 4.3 be awarded by International Competitive Bidding, that the solar capacity referred to in Section 4.5 be contracted through auction rather than negotiated with equipment suppliers, and that the LNG import terminals be tendered separately from generation, on lowest regasification tariff with a statutory open-access obligation, so that no generator controls its rivals' fuel. Regulatory capture — whether by ministries suppressing tariffs for political reasons or by incumbents blocking competition — is among the most common failure modes in the region's reform experience, making PUC independence, transparent procedures, and defined appeals processes foundational to the rest of the program.

Table 1 lays out the proposed reform calendar. Regulatory and institutional steps can proceed largely in parallel with the emergency-generation and DISTCO workstreams described below, and are deliberately sequenced to have the legal and tariff framework in place before major CCGT capital commitments are required.

4.2 Emergency Generation

Immediate deployment of Floating Power Plants (Powerships) and Floating Storage and Regasification Units (FSRUs) at Havana (450 MW) and Santiago de Cuba (300 MW) would provide a bridge while longer-lead-time CCGT construction proceeds — a gap of roughly five years even under an accelerated schedule. Financial viability requires Power Purchase Agreements with dollar-revenue anchor clients (hotels, mining operations) and wheeling-rate regulations permitting

Table 1: Power Sector Reform Calendar and Technical Assistance Costs, July 2026–October 2029.

Step	Duration (mo.)	Cost (US$M)
1. Develop wheeling and large-client regulation	2	2
2. Draft sector strategy and expansion plan	3	4
3. Corporatize and unbundle UNE	3	3
4. Develop and award DISTCO operating contracts	6	6
5. Enact legal framework	6	2
6. Establish and train regulator (PUC)	6	2
7. Phase in cost-recovery tariffs	24	1
Total (excl. investment)	**~40, overlapping**	**20**

direct sales to large consumers. The premium paid for speed is modest against what it buys. Weighted by capacity, floating generation costs $157/MWh against $104/MWh for the combined-cycle plants that follow — a premium of roughly $242 million a year at a 70 percent capacity factor. That premium purchases closure of 48 percent of the 1,474 MW peak deficit five years earlier than the permanent plant could deliver it, avoiding blackout costs of $2.9–7.3 billion a year. The ratio is between twelve and thirty to one, and it is the strongest single result in this analysis. Procurement discipline nonetheless applies here, and is hardest to maintain, because emergency generation is where the pressure to sole-source is greatest and where the international price record is worst. The approach proposed is a time-boxed competitive process — pre-qualification of floating-generation suppliers during the preparatory phase described in Section 7, with bids solicited on a compressed schedule once a transition begins. Contract structure matters as much as the award process: Foster and Rana (2020) document that the take-or-pay provisions common in emergency and early IPP contracts guarantee payment regardless of demand and build a contractual rigidity that constrains later market development, and that where governments absorbed excessive currency or fuel-price risk — as in Pakistan and the Philippines around the Asian financial crisis — the power sector became a major contributor to public debt. The Latin American supply auction, in which generators compete to supply distribution companies long-term without take-or-pay provisions, is the better model. Unit sizing remains subject to a least-cost generation and port-logistics study.

4.3 Distribution Company (DISTCO) Restructuring ($1,150 million)

DISTCOs are where the utility meets the customer and are therefore the critical link in any reform; without well-performing DISTCOs, sector reform is not viable. The program proposes operating/management contracts, awarded by International Competitive Bidding, for three DISTCOs, whose proposed territorial division is shown in Table 2, covering loss-reduction performance incentives, grid rehabilitation, and deployment of prepaid meters.

Table 2: Proposed DISTCO Territorial Division.

DISTCO Zone	Customers (millions)	Share of Total
Havana	1.1	33.3%
Central	1.2	36.4%
East	1.0	30.3%
Total	**3.3**	**100.0%**

The estimated economic IRR of this intervention, based solely on the value of recovered electricity from reduced technical losses, is 24 percent — a figure that excludes the economic value of reduced blackouts entirely.

4.4 Social Protection ($1,590 million)

A 75 kWh/month hard-cap lifeline tariff would protect 1.8 million low-income households at an annual cost of $318 million, financed by a five-year donor bridge covering the gap between the current lifeline tariff (~$0.004/kWh) and a full cost-recovery tariff (~$0.20/kWh). This is best understood as a financing mechanism rather than charity: it is what makes cost-recovery tariffs politically viable and PPAs bankable. Administered through prepaid meters programmed to provide the monthly credit and then require market-rate top-up, the subsidy is auditable, targeted, and fiscally bounded — in contrast to blanket utility-revenue subsidies, which are neither.

4.5 Long-Term Generation: The CCGT Program ($3,915–4,651 million)

The long-term pillar is construction of 2,000 MW of land-based combined-cycle capacity as four 500 MW units across two sites, expected to be financed by private investors, commercial banks, and MDBs once the legal and regulatory framework and DISTCO reform are in place. Four units rather than two costs roughly $375 million in lost scale economies and about three dollars per MWh in levelized cost, but it doubles the number of sponsors the sector can support and is the difference between a market that could eventually become competitive and one foreclosed at commissioning. Regasification cost is unaffected, because FSRU requirements

Table 3: CCGT and FSRU Implementation Calendar, 2026–2036. The four units at 85 percent capacity factor would produce approximately 14.9 TWh, against a displaceable legacy pool of 11.7 TWh. The transmission cost is an order-of-magnitude placeholder pending an engineering estimate.

Phase	Duration (mo.)	Cost (US$M)
Feasibility studies, site selection, permits	9	15
Financing and procurement (WB/IDB loans, EPC contracts)	24	20
Mariel: two 500 MW units and FSRU	30	1,958
Cienfuegos: two 500 MW units and FSRU	24	1,958
Oil-plant decommissioning and site remediation	18	100
Eastern transmission reinforcement	48	600
Total	**105**	**4,651**

follow site count rather than unit count: two 500 MW units at one site share a single terminal. Mariel and Cienfuegos are the proposed sites. Both are brownfield — the Máximo Gómez and Carlos Manuel de Céspedes plants respectively — so interconnection at transmission voltage, cooling water, switchyard and industrial zoning are inherited rather than built, and both are pocket bays offering better hurricane shelter for a moored FSRU than an open roadstead. Mariel adds a working legal regime in the Zona Especial de Desarrollo, which matters for a first-mover terminal concession when the general legal framework is still being drafted. The cost of this siting is that no new baseload is located in the East, whose DISTCO serves a million customers and which currently carries half the legacy thermal fleet; the eastern transmission reinforcement in Table 3 is what allows that fleet to retire. Table 3 lays out the implementation calendar; the hard constraint is that even under an accelerated schedule, roughly five years elapse before the first plant generates power, which is why the emergency floating generation described in Section 4.2 is proposed as a bridge rather than an alternative.

These plants would provide the dispatchable backbone that complements Cuba's solar program (2,000 MW targeted by 2028, with 800 MWh of paired storage capacity, potentially supplying up to 31 percent of generation) — gas and solar function as complements, not substitutes, in this framework. Looking further ahead, once the CCGT backbone, reformed DISTCO billing infrastructure, and a competitive telecommunications network are in place, the distributed solar-plus-storage assets create the conditions for Virtual Power Plant architecture, a second-generation efficiency measure on a 10–15-year horizon that recent World Bank work treats as realistic, contingent on the first-generation reforms proposed here succeeding.

5. Economic and Financial Analysis

The MARKAL-TIMES modeling exercise of Wright, Belt, et al. (2010) concluded, robustly, that CCGT generation would anchor the least-cost expansion path for Cuba's power sector. Two developments since 2010 have strengthened that conclusion: FSRUs have made LNG import financially feasible without a large, lumpy regasification investment, and grid-connected solar PV — infeasible in 2010 given Cuba's ambient humidity — is now a viable complement to thermal generation.

Table 4 summarizes program costs by component, and Table 5 reports the economic and financial results. Total program cost is $7.3 billion at 2025 prices ($9.0 billion adjusted for expected US Producer Price Index inflation over the implementation period), of which $2.8 billion would require donor grant support, most plausibly structured with US Government and/or MDB guarantees to crowd in the remaining private and concessional financing.

Benefits are estimated on the two margins conventional in power sector appraisal (ADB 2013). On the supply margin, generation displaced from the existing fleet is valued at the resource cost saved. Because the legacy plants' capital is sunk, that saving is their avoidable cost — fuel and non-fuel operations and maintenance — and not their full levelized cost; valuing displacement at the $328/MWh fleet LCOE would count recovery of capital that has already been spent. Fuel is priced at CIF import parity, since Cuba is a net petroleum importer and a barrel freed at the plants reduces imports rather than adding exports. Weighting the four segments of the legacy pool — steam plant on domestic crude and on imported fuel oil, and the fuel-oil and diesel generator sets, whose shares are reconstructed from ONEI data — gives an avoidable cost of approximately $162/MWh against $104/MWh for the new capacity.

On the demand margin, output that is genuinely incremental rather than displacing is valued at willingness to pay. Willingness to pay for it is taken as the average of the cost-recovery tariff and the cost of the coping alternative, the latter anchored at $400/MWh (IEG 2008). That anchor is deliberately conservative on two counts. First, the recurring failure of rural electrification programs is that connection does not produce consumption, because households cannot afford the appliances that make electricity valuable; the IEG values are conditional on an uptake that frequently does not materialize. In Cuba the refrigerators, fans, water pumps and televisions are already installed and standing idle, so utilization is revealed rather than assumed. Second, the transfer implicitly treats outages as scheduled rationing that households can plan around. Cuba experienced eighteen total system collapses between

Table 4: Program Costs by Component, 2025 Prices (US$ millions). PPI-adjusted total: $9.0 billion.

Component	Total (US$M)	Of Which, Donor (US$M)
Legal/Regulatory Framework	20	20
Social Protection (Lifeline Subsidy)	1,590	1,590
DISTCO Reform (management, CAPEX, prepaid meters)	1,150	1,150
Long-Term CCGT Generation (four units, two sites)	3,915	0
Eastern transmission reinforcement	600	0
Total (2025 prices)	**7,275**	**2,760**

Table 5: Economic and Financial Results. Note: DISTCO IRR reflects only the value of recovered electricity from reduced technical losses and excludes avoided blackouts. CCGT returns combine the supply margin (resource cost saved on displaced generation) and the demand margin (willingness to pay for incremental supply); the supply-margin-only figure is shown as a memo to isolate the two. Equity IRRs assume 70 percent leverage at concessional (3 percent, 30 years) and commercial (9 percent, 15 years) terms; the ten-point gap between them is the measurable value of early accession to the IMF, World Bank and IDB. IRR rather than MIRR is reported throughout, since each cash flow has a single sign change and the modified measure would understate returns by imposing a 10 percent reinvestment assumption. The financial IRR exceeds the economic IRR because the cost-recovery tariff is set against a system-wide cost base that includes the far more expensive legacy fleet. These are identification-level (World Bank PID / IDB Profile I) estimates, with an accuracy range of ±20–30 percent, intended to establish strategic and economic viability ahead of formal project preparation and appraisal. The $328/MWh figure for the existing plants is a full levelized cost that includes recovery of capital; the $162/MWh avoidable cost excludes it, because that capital has already been spent. The difference between the two is not a discrepancy but the distinction that governs which figure belongs in a displacement calculation. Within the avoidable cost, fuel accounts for 88 percent and non-fuel operations and maintenance for 12 percent; the latter is assumed at $20/MWh rather than taken from audited accounts, and a range of $20–40/MWh moves the economic IRR by about two percentage points. The counterfactual also excludes the rehabilitation expenditure that keeping a fleet of this age in service would require, and is conservative on that count as well.

Proposal	Units	Result
DISTCO operating contracts — Economic IRR	%	24
Emergency generation — Havana LCOE	US$/MWh	143
Emergency generation — Santiago LCOE	US$/MWh	177
CCGT program — LCOE at bus bar	US$/MWh	104
Seven large liquid-fuel plants — full LCOE	US$/MWh	~328
Fleet-wide average LCOE (incl. solar, CCGT)	US$/MWh	~245
CCGT program — Economic IRR (supply and demand margins)	%	19
CCGT program — Economic IRR including avoided re-charter	%	21
CCGT program — Economic IRR, supply margin only (memo)	%	11
CCGT program — Financial IRR at derived bus bar ($165/MWh)	%	25
Legacy fleet — avoidable cost (fuel and O&M only)	US$/MWh	~162
CCGT program — Benefit-cost ratio	ratio	1.66
CCGT — Equity IRR, concessional debt	%	57
CCGT — Equity IRR, commercial debt	%	47
Emergency bridge — blackout cost avoided per $1 of premium	ratio	12–30

February 2024 and June 2025, nine of them in 2025 alone, with peak deficits between 777 and 2,667 MW; the cost of an unannounced collapse attaches to its unpredictability — spoiled food, loss of water pressure, interrupted production, restart sequences — rather than to the energy foregone. The resulting $300/MWh is accordingly a floor. It sits well below the $1,854–4,635/MWh implied by top-down estimates of Cuban blackout costs, and an order of magnitude below the $6,040–13,430/MWh obtained by scaling South African value-of-lost-load estimates by relative income. Valued at the latter the program would return upwards of 60 percent; the conservative figure is retained throughout. The two margins are additive; avoided blackout cost is not added to them, because it measures the same benefit as the demand margin by a different route.

The central finding of this analysis is that financial — not economic — viability is the binding constraint on Cuba's power sector reform. Given the depth of poverty and the share of households unable to pay cost-recovery tariffs during the first years of a transition, the lifeline tariff described in Section 4.4 is not a peripheral welfare measure but the mechanism that makes the entire financing structure bankable. This is consistent with the broader record: Foster and Rana (2020) find cost recovery remarkably difficult to achieve and sustain across the developing world, and that what limited progress was made owed more to efficiency improvements than to tariff increases. That is an argument for the ordering proposed here, in which loss reduction delivers benefits through efficiency and can begin immediately while the tariff path is bridged by the lifeline subsidy until it can be sustained. The dependence runs in both directions. Because falling losses mean more of each generated megawatt-hour reaches a paying customer, the DISTCO program is worth some five points of financial IRR to the combined-cycle investment — 25 percent at the ten percent loss target against 20 percent if losses were to deteriorate to twenty. Loss reduction is not a public-good side benefit of the distribution contracts; it is the mechanism that makes the generation program financeable.

These results compare favorably with returns documented for other post-conflict and transition-economy power sector interventions. Belt et al. (2018), analyzing power sector reform options in Haiti under a comparable identification-level methodology, found economic IRRs in the 12–18 percent range for loss-reduction and generation-efficiency investments in a similarly capital-starved, low-institutional-capacity setting — comparable to the 24 percent and 19 percent figures reported here for Cuba's DISTCO and CCGT components respectively. The difference is consistent with Cuba's starting point: a generation fleet operating at a fraction of the efficiency of modern CCGT technology represents an unusually large efficiency gap to close, and correspondingly large returns to closing it. This comparison also underscores why the reported IRRs, though already favorable, likely understate the full case for investment: neither this analysis nor the Haiti precedent it is compared against incorporates the economic value of avoided service interruptions, which in both cases exceeds the direct generation-cost savings by a wide margin.

Because the underlying cost and efficiency data were assembled through the triangulation method described in Section 3.1 rather than drawn from audited utility accounts, the identification-level results reported in Table 5 should be read with an explicit accuracy band of ±20–30 percent, consistent with World Bank Project Identification Document and IDB Profile I conventions. Two results are robust to that uncertainty range. First, the cost differential between new combined-cycle capacity and the existing fleet is large on either measure — roughly threefold against the fleet's full levelized cost, and roughly 1.6 times against the avoidable cost that properly measures the saving — so that combined-cycle replacement clears the standard multilateral hurdle rate of 10 percent across the stated range. It should be noted that on the supply margin alone the program returns 11 percent, close to the hurdle; it is the demand margin, the value of supply that does not exist today, that carries the result. That margin is bounded below: valuing incremental output at the tariff itself, and so assuming no consumer surplus whatever, still returns 14 percent, because the cost-recovery tariff net of distribution cost and losses exceeds the delivered cost of new capacity. The willingness-to-pay assumption determines whether the answer is 14 percent or 19, not whether the program is justified. Second, the DISTCO economic IRR, though more sensitive to the pace of loss reduction actually achieved, remains positive under every scenario examined in which any loss reduction occurs at all — the risk in that component is to the magnitude of the return, not its sign. The component most sensitive to the underlying data uncertainty is the financial (as opposed to economic) IRR of the CCGT program, since it depends on the bus bar price ultimately negotiated, which is itself a function of financing structure and risk allocation decisions not yet made. One specific input uncertainty deserves separate mention. The proposed plants would replace the seven large liquid-fuel plants, not ENERGAS, and unlike ENERGAS they would run on imported LNG rather than domestic associated gas. Their LCOE therefore turns on the delivered gas price, modeled here as a Henry Hub benchmark of $3.00/MMBtu plus a landed-cost markup of $6.50/MMBtu covering liquefaction, shipping and regasification. That markup is the single most consequential assumption behind the $104/MWh figure: across its plausible range of $5.00–8.00/MMBtu, delivered fuel cost moves by roughly $10/MWh either way. ENERGAS's domestically sourced associated gas is materially cheaper, but its supply is tied to Cuban oil production and cannot be scaled to serve 2,000 MW of new capacity. A second uncertainty is symmetric: the avoidable cost of the fleet being displaced depends on the world oil price, taken here at $75/bbl WTI, the mid-point of the EIA's August 2026 forecast of $81 for 2026 and $65 for 2027. At $65 the supply margin alone would not clear the hurdle rate; at $90 it comfortably would.

6. Discussion: Sequencing, Risk, and Alternatives for Further Study

The transition government will inherit a system that cannot wait for the five-year lead time CCGT construction requires; this is precisely why mobile, scalable emergency generation is proposed as a bridge rather than a permanent solution. A full least-cost expansion study — covering generation mix, transmission investment, and the phased retirement of the existing fleet — should be among the first actions of a transition government, and would likely refine the specific asset configuration proposed here.

Three risk factors deserve explicit attention. First, execution risk in the DISTCO workstream: the 24 percent economic IRR estimate assumes that a 20 percent

to 10 percent loss reduction is achieved on the stated five-year schedule; slower implementation delays the benefit stream without reducing the upfront CAPEX, thereby compressing the return. It bears emphasis that this estimate excludes avoided blackouts entirely. Apportioning the blackout-avoidance benefit between the floating plants and the operating contracts on a MW-equivalent basis — under which the contracts account for 6 percent of the benefit in the second year, rising to 23 percent by the seventh — would raise the DISTCO economic IRR from 24 percent to approximately 74 percent and its net present value from $734 million to $5.5 billion. The lower figure is retained as the conservative base case. Second, fuel-price risk on the emergency-generation bridge: the $143–177/MWh LCOE range for floating generation is sensitive to LNG spot prices during the years before long-term supply contracts can be negotiated, and a sustained price spike would widen the gap between emergency-phase and CCGT-phase generation costs. Third, political risk to the tariff-reform schedule itself, which this paper treats as exogenous but which the wider reform literature (Foster and Rana 2020) identifies as the single most common point of failure in comparable transitions — governments facing acute short-term political pressure have repeatedly deferred the tariff increases that reform programs assume, undermining the financial viability of exactly the DISTCO and CCGT investments this paper evaluates.

A fourth consideration is organizational rather than technical, and the reform literature treats it as decisive. Kotter's finding, drawn from decades of research on institutional change, is that no major reform survives the period in which its costs are visible and its benefits are not unless a guiding coalition with sufficient authority, technical credibility and political standing has been assembled to carry it. Power sector reform in Cuba will require such a coalition to command the sector ministry, the new regulator and the donor financing apparatus simultaneously, and to address the position of Unión Eléctrica's workforce, whose interests are legitimate and whose cooperation is a practical precondition for the loss-reduction schedule on which the DISTCO returns depend. The Latin American reforms that anchor Section 4.1 broadly succeeded where such coalitions were assembled early and faltered where reform was driven by a finance ministry acting alone. The sequencing proposed here is designed with that in mind: the early visible wins matter not only for their direct returns but because they supply the evidence of progress that holds a coalition together through the years before the generation program delivers power.

Several extensions merit further study once the least-cost expansion baseline is established: the siting of the third and fourth combined-cycle units at Felton or Santiago rather than Cienfuegos, which would eliminate the eastern transmission requirement at the cost of a third import terminal or a small-scale LNG shuttle, and which a least-cost study should price rather than assume; a fixed regasification facility to replace FSRUs once import volumes justify it; a US gas pipeline to reduce long-run delivered fuel costs; Battery Energy Storage Systems to firm intermittent solar output and provide voltage/frequency regulation beyond what the currently planned 800 MWh of storage capacity can deliver; and a submarine HVDC interconnector from Florida, complementary to rather than a substitute for land-based generation, though complicated by deep-water sections of the Florida Straits.

7. US and International Partner Engagement

The reform program outlined here creates specific, near-term entry points for US and multilateral engagement, several of which do not require large capital commitments up front. US LNG exporters gain a proximate new market roughly 90 miles from their existing Gulf Coast infrastructure; American engineering, construction, and utility-management firms gain a pipeline of ICB-tendered contracts across the DISTCO and CCGT workstreams; and US Government and/or MDB guarantees can crowd in private capital for the CCGT program rather than requiring direct appropriations for the full $7.3 billion. A first practical step, achievable before any large capital program begins, is for Cuba to rejoin the IMF and World Bank and join the IDB, alongside formation of a donor consultative group spanning the US, Canada, and Latin American and European partners. Regulatory capacity building — for the new PUC's staff in particular — has a natural home in institutions with existing track records in the region: the Public Utility Research Center at the University of Florida, which has trained Latin American and Caribbean regulators for decades, and the National Association of Regulatory Utility Commissioners, both of which maintain working relationships with the MDBs likely to finance other elements of the program.

The sequencing of donor engagement matters as much as its scale. The technical assistance items in Table 1 — regulatory drafting, UNE corporatization, PUC training — are inexpensive, fast to deploy, and do not require a resolved fiscal or political settlement to begin; they are the natural first tranche of any donor commitment and can proceed on a purely preparatory basis, as has been the practice in comparable pre-transition planning exercises for other post-conflict power sectors. The larger capital commitments — the DISTCO CAPEX and, especially, the CCGT program — are properly held for a resolved transition government with a credible tariff-reform commitment, since disbursing capital ahead of that commitment would repeat a pattern of donor-financed assets stranded by subsequent policy reversal that recurs throughout the power sector reform literature discussed in Section 2. This two-tier approach — no-regret preparatory work now, owner-committing capital later — allows donors to maintain readiness without assuming the execution risk that Section 6 identifies as the program's central vulnerability.

8. Conclusion

Cuba's power sector collapse is not a peripheral economic problem; it is the central obstacle to a viable

political and economic transition, and a driver of migration pressure with direct US security implications. This paper's identification-level analysis finds that a five-pillar reform program — legal and regulatory reform, emergency floating generation, DISTCO restructuring, targeted social protection, and long-term CCGT generation — is both economically and, with an appropriately designed lifeline tariff, financially viable, at a total cost of $7.3 billion, of which under half requires donor grant financing. Because the reported returns exclude the economic value of avoided blackouts entirely, they represent a conservative lower bound.

The central policy implication is that donor and multilateral engagement should focus not on whether these investments are justified — they clearly are, on both economic and comparative grounds — but on two design questions this paper has tried to make concrete: how to structure the social-protection bridge that makes the program financeable during the difficult early years of a transition, and how to sequence donor commitments so that low-cost preparatory work can proceed immediately while capital-intensive commitments await a credible tariff-reform commitment from a transition government. Both are questions the reform literature has answered before, in other countries facing comparable fiscal and institutional constraints; the task ahead is adapting those answers to Cuba's specific circumstances rather than discovering them anew.

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What Determines the Allocation of U.S. Federal Energy and Environmental Investment? Evidence from the IIJA–IRA Implementation Period

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Abstract

The Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA) marked the largest expansion of federal energy and environmental investment in U.S. history. While these programs sought to accelerate the energy transition through unprecedented public investment, comparatively little is known about the principles that governed the geographic allocation of those investments. This question is increasingly important as governments around the world rely on public investment not only to promote decarbonization but also to advance resilience and distributional equity.

This study examines the determinants of federal energy and environmental investment across the fifty U.S. states and the District of Columbia during fiscal years 2021–2024. Pooled ordinary least squares models with year fixed effects and state-clustered standard errors evaluate whether investment allocation is more strongly associated with climate-related need, demographic scale, or public demand for climate policy.

Population emerges as the dominant determinant of investment allocation. The estimated population elasticity is approximately 0.70 and remains remarkably stable across all model specifications. By contrast, disaster exposure exhibits no statistically significant association with investment under any specification or alternative measure of disaster exposure. Public support for regulating carbon dioxide is positively associated with investment in simple models but becomes statistically insignificant after accounting for demographic characteristics, indicating that the relationship is not robust.

The estimated population elasticity is significantly below one, implying that investment increases less than proportionally with population and that smaller states systematically receive higher per-capita allocations than larger states. Although these findings are descriptive rather than causal, they suggest that federal energy investment during the IIJA–IRA implementation period primarily reflected demographic scaling rather than climate-related need. More broadly, the results highlight the importance of examining allocation mechanisms when evaluating whether public investment supports resilience and equity objectives during the energy transition.

Keywords

Energy investment, Energy transition, Energy governance, Public investment allocation, Climate policy, United States

1. Introduction

Although commercial finance and private investors account for most global energy investment, governments play an increasingly important role in directing capital through public finance, industrial policy, and targeted investment programs. Public investment has become a critical instrument for accelerating the energy transition because private capital tends to underinvest in public goods, infrastructure, and early-stage technologies (IEA, 2025). In the United States, this transformation has been exemplified by the Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA), which together represent the largest federal commitment to energy and environmental investment in the nation's history (The White House, 2022). Where investment is allocated ultimately determines which regions benefit from public spending and whether policy objectives are translated into realized outcomes. This raises a fundamental policy question: what determines where public investment is allocated?

During the implementation of the IIJA and IRA, U.S. climate policy explicitly emphasized that public investment should advance not only economic efficiency but also distributional equity. Established under Executive Order 14008, the Justice40 Initiative set a government-wide objective that at least 40 percent of the benefits of covered federal investments flow to disadvantaged communities, placing distributional equity at the center of federal climate policy (Exec. Order No. 14008, 2021). Although Executive Order 14008 and the Justice40 Initiative were revoked in 2025, the initial implementation period remains an important empirical setting for understanding how large-scale public investment was allocated before subsequent policy changes (U.S. GAO, 2025). The subsequent review, modification, suspension, and cancellation of awards further underscore that allocation decisions can be as consequential as appropriations themselves, making the study of allocation relevant regardless of subsequent policy changes.

Existing research on the IIJA and IRA has primarily focused on two broad themes. First, studies evaluate the aggregate impacts of federal investment on emissions, employment, and private investment (Bistline et al., 2023; Jenkins et al., 2022). Second, they examine the normative objectives of Justice40 and other equity-oriented investment initiatives (Rudik et al.,2025). However, whether these normative objectives translated into the observed geographic allocation of federal energy investment remains largely unknown. Allocation therefore remains an empirical question rather than an administrative assumption.

To address this gap, this study examines the allocation of federal energy and environmental investment across the fifty U.S. states and the District of Columbia during fiscal years 2021–2024. Using a balanced state-level panel dataset combining federal investment obligations, FEMA disaster declarations, demographic characteristics from the American Community Survey, and state-level climate policy opinion estimates from the Yale Program on Climate Change Communication, we evaluate whether federal investment allocation is more strongly associated with climate-related need, demographic scale, or public support for climate policy.

This study makes three contributions. First, it provides one of the earliest allocation analyses of the geographic allocation of federal energy and environmental investment during the implementation of the IIJA and IRA. Second, it evaluates competing determinants of allocation, including climate-related need, demographic scale, and public demand. Third, it contributes to the literature on energy governance by shifting attention from the magnitude or intended objectives of public investment toward the allocation mechanisms through which public resources are distributed. More broadly, the findings provide evidence relevant to governments seeking to design public investment strategies that are both effective and equitable during the energy transition.

2. Literature Review

Recent scholarship characterizes the Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA) as a fundamental shift toward mission-oriented industrial policy, using large-scale public investment to accelerate decarbonization, strengthen domestic manufacturing, improve energy security, and promote regional economic development. Rather than relying primarily on market-based climate instruments, these policies combined grants, tax credits, loans, and regulatory incentives to reshape the U.S. energy transition (Quinn & Stokes, 2026).

Existing studies have therefore focused primarily on the effectiveness of these investments in stimulating clean energy deployment, employment, and technological change. However, comparatively less attention has been devoted to understanding how these unprecedented public resources were geographically allocated across states. More recent research argues that the effectiveness of the IIJA and IRA depends not only on the amount of federal investment but also on how programs are implemented across different levels of government. Gadzanku et al. (2026) describe the IIJA and IRA as a system of cooperative federalism, in which federal agencies, state governments, local institutions, and private actors jointly determine how federal resources translate into policy outcomes They further argue that implementation varies substantially across states because administrative capacity, political commitment, and institutional arrangements differ across jurisdictions.

This perspective shifts attention from the scale of investment toward the mechanisms through which public investment is translated into regional outcomes. Nevertheless, existing studies primarily examine program implementation, policy durability, and institutional coordination rather than the empirical allocation of investment itself.

A longer tradition in political economy similarly suggests that public resources are rarely allocated solely according to objective need. Studies of intergovernmental transfers demonstrate that federal spending is influenced by statutory funding formulas, political incentives, institutional arrangements, and demographic characteristics in addition to measures of need (Knight, 2002; Larcinese et al., 2006; Berry et al., 2010). Garrett and Sobel (2003) further show that even FEMA disaster assistance is shaped by political and demographic factors beyond disaster severity. Considering the FEMA disaster assistance is one of the ederal government's most explicitly need-based transfer program, these studies suggest that observed allocation patterns should be treated as empirical outcomes rather than direct reflections of policy objectives.

Energy justice scholarship has emphasized that successful energy transitions should be evaluated not only according to efficiency but also according to the distribution of benefits and burdens (Sovacool & Dworkin, 2015). The Justice40 Initiative institutionalized this principle by explicitly directing that federal investments benefit disadvantaged communities. Existing research therefore provides valuable insights into the normative goals of equitable public investment as well as the implementation challenges associated with Justice40.

However, the literature leaves an important question unanswered. Existing studies explain what federal energy investment is intended to achieve, how public programs should be implemented, or how public resources are generally allocated. Comparatively little empirical evidence exists regarding the allocation principles that actually governed federal energy and environmental investment during the implementation of the IIJA and IRA. In particular, it remains unclear whether observed allocation primarily reflected climate-related need, demographic scale, or public demand for climate policy. This study addresses that gap through a state-level empirical analysis of federal investment allocation.

3. Data and Method

This study examines the determinants of the geographic allocation of federal energy and environmental investment across U.S. states during the implementation of the Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA). To do so, this research uses a balanced state-year panel covering the fifty U.S. states and the District of Columbia from fiscal years 2021 through 2024, yielding 204 observations. The unit of analysis is the state-year. Rather than evaluating the effectiveness of federal investment programs, the objective is to explain the factors associated with how federal investment was geographically allocated.

Following the research question, we evaluate three competing explanations for investment allocation. First, climate-related need is captured by disaster exposure.

Second, demographic scale is represented by state population. Third, public demand for climate policy is measured using state-level climate policy preferences. Together, these variables can assess whether federal investment was more closely associated with need, population, or public support for climate action.

3.1 Data

The dependent variable is annual federal energy and environmental investment obligations obtained from Portland State University's Federal Energy and Environment Investment Project. This research uses obligations rather than disbursements because obligations represent legally binding federal funding commitments at the time allocation decisions are made, whereas disbursements occur gradually as projects are implemented. Obligations therefore provide the appropriate measure for analyzing allocation decisions rather than project execution. Multi-year awards are recorded in the fiscal year in which they are obligated, and awards that cannot be attributed to individual states are excluded from state totals.

Climate-related need is measured using FEMA Disaster Declarations Summaries. Because the original FEMA database is organized by disaster declaration and designated county, simply counting records would substantially overstate disaster frequency in states where individual disasters affect many counties. This research therefore construct the disaster measure by counting unique disaster declaration numbers within each state-year. State-years with no disaster declarations are coded as zero rather than treated as missing in order to preserve low-exposure observations.

Demographic characteristics are obtained from the American Community Survey (ACS) 1-Year Estimates, including state population, median household income, median age, female population share, child population share, and the shares of households primarily using natural gas or electricity for home heating.

Public demand for climate policy is measured using the Yale Program on Climate Change Communication. Specifically, this research uses the estimated percentage of adults in each state supporting the policy "Regulate carbon dioxide (the primary greenhouse gas) as a pollutant" (Howe et al., 2015). These estimates are generated using multilevel regression with post-stratification (MRP). Because this variable reflects support for a specific climate policy rather than perceived climate risk, it is interpreted as a measure of public policy demand.Table 1 summarizes all variables used in the empirical analysis.

3.2 Specification

To evaluate the determinants of federal investment allocation, we estimate pooled ordinary least squares (OLS) regressions with year fixed effects. The dependent variable is the natural logarithm of annual federal energy and environmental investment obligations received by each state. The primary explanatory variables correspond directly to the competing allocation principles proposed in this study:Climate-related need: log disaster declarations (+1), Demographic scale: log population, Public demand: percentage supporting carbon dioxide regulation

The models additionally control for demographic and socioeconomic characteristics, including female population share, child population share, median age, median household income, and household heating-fuel composition. Year fixed effects capture nationwide changes affecting all states, including the phased implementation of IIJA and IRA programs.

The model is like below.

$$ln(Investment_{it}) = \beta_0 + \beta_1\, ln(Disasters_{it}+1) + \beta_2\, Opinion_{it} + \beta_3\, ln(Population_{it}) + X_{it}'\gamma + \delta_t + \varepsilon_{it}$$

where X is the vector of demographic controls, δ_t denotes year fixed effects, and ε is the error term.

Standard errors are clustered at the state level to account for repeated observations within jurisdictions over time. The estimated coefficients are interpreted as descriptive associations rather than causal effects. Federal investment allocation reflects legislative design, administrative discretion, program eligibility, and state characteristics that cannot be fully isolated in an

Table 1: Variables

Variable	Measure	Source
Investment	Federal obligations (log)	PSU Federal Energy & Environment Investment Project
Disaster	FEMA disaster declarations (log+1)	FEMA
Population	State population (log)	ACS
Public demand	Support for CO_2 regulation (%)	Yale Climate Opinion Maps
Income	Median household income	ACS
Age	Median age	ACS
Female share	Female population share	ACS
Child share	Population aged 0–17	ACS
Gas heating	Household share	ACS
Electric heating	Household share	ACS

observational setting. Accordingly, the analysis identifies the empirical correlates of investment allocation rather than causal impacts.

4. Results

4.1 Descriptive Patterns

Table 2 reports descriptive statistics. Dispersion is wide on every dimension: investment ranges from $0.63 billion to $24.9 billion per state-year, population from 0.58 to 39.4 million, and disaster declarations from zero to fifteen.

Figure 1 shows national totals rising from $157 billion in FY2021 to $222 billion in FY2024, a 41 percent increase concentrated in the final two years — consistent with the lag between authorization and obligation. Because only four national observations exist, we make no formal trend claim; the year fixed effects in the regressions carry this information.

Figure 2 previews the central result. Log investment is tightly related to log population (r = 0.89) and essentially unrelated to log disaster declarations (r = 0.14). Figure 3 maps investment per capita and shows the corollary: the highest per-capita recipients are small, low-population states — Alaska, Wyoming, the Dakotas, Vermont, Maine, West Virginia — while California, Texas, Florida, and Arizona sit in the bottom quintile. Excluding the District of Columbia, whose $4,363 per capita reflects the concentration of federally administered activity rather than allocation to residents, per-capita receipts still vary more than eight-fold across states, from $2,516 in Alaska to $303 in Florida.

4.2 Population and the Allocation of Investment

Table 3 reports the main estimates. Column 1 regresses log investment on log population alone: the elasticity is 0.662 (SE 0.056) and explains 81 percent of the variance. Column 5, the full specification, yields 0.703 (SE 0.056). The elasticity is stable across every column and every robustness check in Table 3.

Two features of this coefficient deserve emphasis. First, it is precisely estimated and dominant: no other variable approaches its explanatory contribution. Second, it is significantly below one (H_0: β = 1 rejected at $p < 0.001$ in all specifications). A ten percent larger state receives roughly seven percent more investment, so allocation per resident falls as population rises. This is the statistical counterpart to the geography in Figure 3, and follows mechanically from formula grants with fixed state minimums — a design feature, not an anomaly, but one whose distributional consequence is rarely stated.

Among the controls, child share (β = −12.17, SE 4.83) and median age (β = −0.118, SE 0.037) are significant and negative, indicating that older and more child-heavy states receive somewhat less conditional on population. Median household income is insignificant, so allocation is neither progressive nor regressive with respect to state wealth. Heating fuel composition has no detectable association.

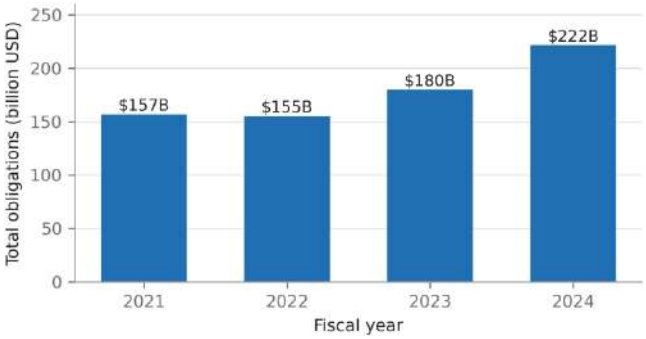

Figure 1: Total federal energy and environmental obligations by fiscal year, 2021–2024.

Table 2: Descriptive statistics, 51 jurisdictions × 4 fiscal years (n = 204).

Variable	Mean	SD	Min	Median	Max
Energy & environment investment ($ bn)	3.50	3.64	0.63	2.47	24.88
Investment per capita ($)	756	872	265	557	11,545
Disaster declarations (count)	2.36	2.54	0	2	15
Major disaster declarations (DR)	1.27	1.37	0	1	7
Counties designated	19.2	30.1	0	7	254
Population (millions)	6.57	7.42	0.58	4.52	39.43
Support for CO_2 regulation (%)	72.1	4.3	61.8	72.2	83.7
Female share	0.503	0.009	0.473	0.504	0.527
Child share (0–17)	0.216	0.019	0.172	0.217	0.283
Median age (years)	39.3	2.20	31.8	39.3	45.1
Median household income ($)	75.7	13.1	48.7	73.9	109.7
Gas heating share	0.518	0.183	0.050	0.545	0.836
Electric heating share	0.371	0.194	0.083	0.326	0.907

Notes: Investment is federal energy and environmental obligations. Disaster declarations are counts of distinct FEMA disaster numbers per state-year.

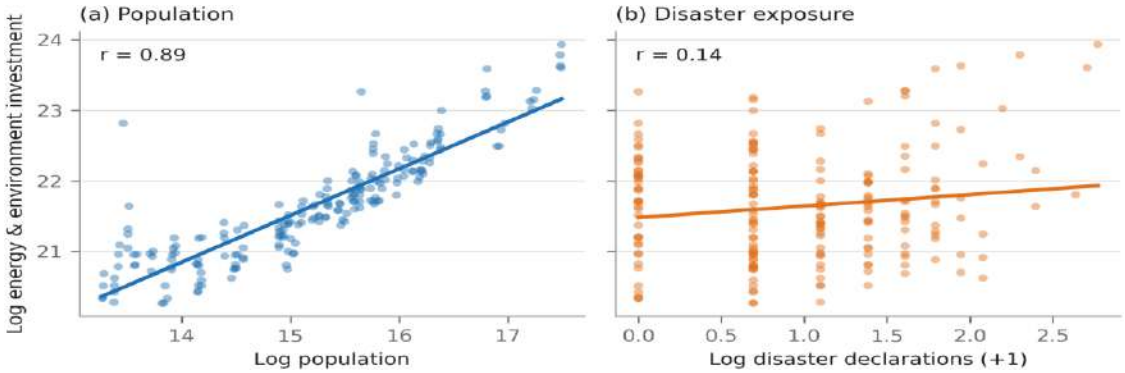

Figure 2: Log investment against (a) log population and (b) log disaster declarations. Each point is a state-year (n = 204); lines are OLS fits.

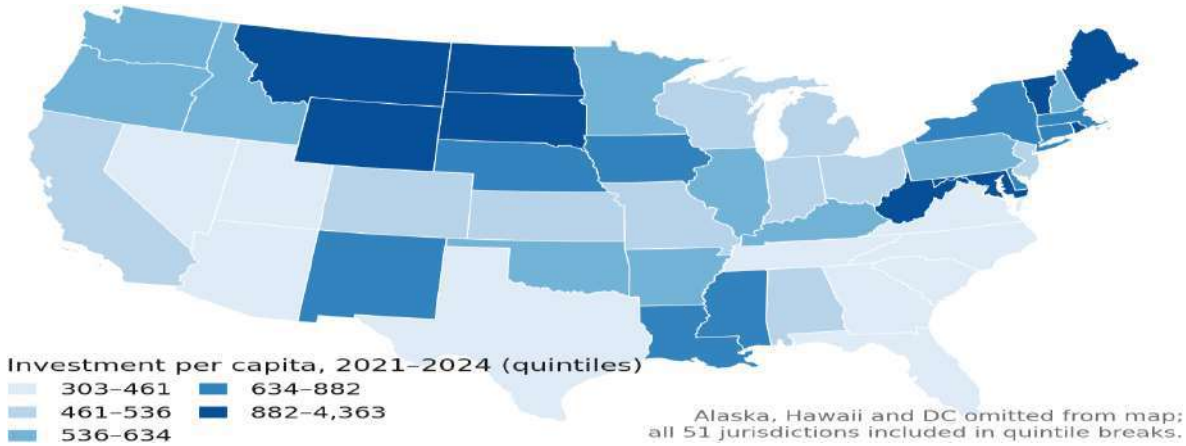

Figure 3: Federal energy and environmental investment per capita, 2021–2024 cumulative, by quintile.

Table 3: Determinants of federal energy and environmental investment. Dependent variable: log investment.

	(1)	(2)	(3)	(4)	(5)
Log population	0.662*** (0.056)	—	—	0.633*** (0.057)	0.703*** (0.056)
Log disaster declarations (+1)	—	0.135 (0.160)	—	0.006 (0.051)	−0.016 (0.044)
Support for CO_2 regulation (%)	—	—	0.069*** (0.021)	0.024* (0.013)	0.007 (0.025)
Female share	—	—	—	—	−3.691 (8.688)
Child share (0–17)	—	—	—	—	−12.167** (4.830)
Median age	—	—	—	—	−0.118*** (0.037)
Median household income ($000)	—	—	—	—	−0.003 (0.007)
Gas heating share	—	—	—	—	−0.221 (0.409)
Electric heating share	—	—	—	—	−0.464 (0.438)
Year fixed effects	Yes	Yes	Yes	Yes	Yes
Observations	204	204	204	204	204
R^2	0.812	0.042	0.172	0.827	0.859

Notes: Pooled OLS. Standard errors clustered by state in parentheses. *** p < 0.01, ** p < 0.05, * p < 0.10. All columns include year fixed effects.

4.3 Climate Need and Public Demand

Disaster exposure shows no association with investment allocation at any stage of the analysis. Column 2 of Table 3 regresses log investment on log declarations alone, with year effects and no other controls: the coefficient is 0.135 (SE 0.160, p = 0.40) and R^2 is 0.042. Adding population and opinion (column 4) leaves it at 0.006; the full specification (column 5) gives −0.016.

This differs from what a records-based exposure measure would suggest, and the difference is instructive. Because the number of FEMA records per state is largely a function of how many counties a declaration covers, that variable correlates with population (r = 0.235) far more than the declaration count does (r = 0.143). A records-based measure therefore imports state size into the hazard variable, and can produce an apparent bivariate hazard effect that is really a population effect. The correct declaration count shows no bivariate association to begin with, so the finding here is not that a disaster effect is absorbed by population.

Table 3 confirms the null is not an artifact of measurement choice. Restricting to major disaster declarations, using the count of designated counties and using the original record count all leave disaster exposure insignificant with the full control set. The null also holds under state fixed effects and excluding the District of Columbia.

Public support for CO_2 regulation follows a different pattern, and one that does not license a strong claim. On its own it is significantly positive (column 3 of Table 2: β = 0.069, SE 0.021). With population and year effects it weakens to 0.024 (SE 0.013, p = 0.073). With the full demographic control set it is 0.007 (SE 0.025, p = 0.77), and it is insignificant under state fixed effects and when the District of Columbia is excluded. Because the coefficient is not robust to the inclusion of standard controls, we report it as suggestive at most and do not build an interpretation on it. Opinion is correlated with population (r = 0.29) and with the demographic composition variables, and the bivariate association appears to reflect that shared variation.

Year effects indicate FY2023 investment 14.0 percent above FY2021 (p = 0.001) and FY2024 35.2 percent above (p < 0.001), consistent with program phase-in.

Population is the dominant and highly robust correlate of allocation, with an elasticity of roughly

Table 4: Robustness of the main coefficients to alternative measures and specifications.

Specification	Log population	Disaster exposure	CO_2 regulation support	N	R^2
(1) Baseline (= Table 2, col. 5)	0.703*** (0.056)	−0.016 (0.044)	0.007 (0.025)	204	0.859
(2) Per-capita dependent variable	−0.297*** (0.056)	−0.016 (0.044)	0.007 (0.025)	204	0.664
(3) Major declarations only (DR)	0.693*** (0.054)	0.059 (0.044)	0.009 (0.025)	204	0.861
(4) Counties designated	0.693*** (0.056)	0.017 (0.019)	0.008 (0.025)	204	0.860
(5) FEMA record count	0.695*** (0.056)	0.010 (0.016)	0.008 (0.025)	204	0.860
(6) State fixed effects	0.596 (3.593)	−0.038 (0.025)	0.031 (0.035)	204	0.965
(7) Excluding District of Columbia	0.766*** (0.049)	0.014 (0.040)	−0.004 (0.023)	200	0.882

Notes: Each row is a separate regression. Rows 1–5 and 7 include the full demographic control set; row 6 replaces it with state fixed effects. Standard errors clustered by state. *** p < 0.01. In row 2 the dependent variable is log investment per capita, so the population coefficient equals the baseline coefficient minus one.

Table 5: Alternative measures of state disaster exposure, fiscal year 2021.

State	Unique declarations	Major declarations (DR)	Counties designated	FEMA records (record count)
Louisiana	10	5	64	554
Texas	3	2	254	513
Florida	4	0	50	74
District of Columbia	1	0	1	1
Wisconsin	0	0	0	0

Notes: The record count conflates the number of disasters with the number of counties each covers. Louisiana's ten 2021 declarations generate 554 records; Texas's three generate 513. Across the panel the record count correlates with log population at r = 0.235, the declaration count at r = 0.143.

0.66–0.70. Disaster exposure has no detectable association under any of four measurements or any specification. Public support for climate policy is positively associated in isolation but does not survive standard controls and is not treated as a robust finding. The population elasticity is significantly below one, so per-capita allocation is regressive in state size.

5. Discussion

5.1 Interpreting the Allocation Pattern

The evidence is most consistent with allocation governed by the architecture of formula grants rather than by hazard targeting. Population enters most federal funding formulas; state minimums and small-state set-asides produce exactly the sub-unitary elasticity observed. On this reading the geography of IIJA–IRA energy investment is largely inherited from pre-existing distributional machinery rather than newly designed around climate objectives.

The disaster null is the more consequential result, and it is stronger than a conventional "confounded by size" story. Had exposure mattered and merely been absorbed by population, one would conclude that need is served indirectly, since large states experience more events. The data do not support even that. Declaration counts are nearly orthogonal to investment throughout, and the apparent hazard relationship reported by records-based measures is an artifact of counting county designations. Federal energy and environmental investment during this period was not, on this evidence, allocated with reference to realized disaster exposure.

This should not be read as evidence of policy failure. Much of this investment targets mitigation and deployment rather than adaptation, and the geography of good wind resource or industrial decarbonization potential need not resemble the geography of hurricanes. Realized disasters are also a backward-looking proxy for prospective risk. The finding is nonetheless relevant to any framework that justifies energy investment partly in resilience terms: at the state level, that justification is not visible in where the money went. It also echoes Garrett and Sobel (2003) from the opposite direction — where they found disaster transfers responding to politics rather than need, we find energy transfers responding to neither, but to demographic scale.

5.2 Policy Implications

Three implications follow. First, evaluating public investment requires attention to allocation, not only to volume; a program can be large and still not reach the regions its rationale invokes. Second, if resilience is an objective, allocation criteria must carry variables that measure it. Declaration counts are a crude proxy, and richer indicators — FEMA's National Risk Index, energy burden, infrastructure age, or the Justice40 disadvantaged-community designations — would need to enter formulas explicitly to shape outcomes, since they evidently do not shape them implicitly. Third, the sub-unitary population elasticity deserves deliberate treatment. Small-state minimums are defensible on administrative-capacity grounds, but they are a distributional choice that is currently made implicitly through formula design rather than argued on its merits. Given the difficulty agencies have had verifying Justice40 benefit flows (GAO, 2024), greater transparency about allocation criteria would serve both accountability and evaluation.

5.3 Limitations and Future Research

The analysis is at state level and cannot identify which households or communities ultimately benefit; state-level proportionality is consistent with within-state concentration in either direction. Disaster declarations proxy realized hazard, not underlying vulnerability or prospective risk, and declarations are themselves partly political (Garrett & Sobel, 2003). A measure such as the National Risk Index would test whether the null extends to forward-looking exposure.

The estimates are associations. Reverse causation is plausible for the opinion variable. Visible federal investment may shift local climate attitudes as readily as attitudes attract investment and both may respond to unobserved state characteristics such as administrative capacity or congressional seniority, which we do not measure. This is a further reason not to interpret the fragile opinion coefficient substantively. With four years and heavy state-level persistence, state fixed effects absorb nearly all identifying variation, so within-state identification is not available here.

Finally, obligations are not outlays. Funds committed in a fiscal year may be spent later or returned, and the geography of obligation may diverge from the geography of realized expenditure. Future work should link investment records to household-level measures of energy burden and to programs such as LIHEAP, and should extend the panel as later fiscal years become available, when within-state variation may permit stronger identification.

6. Conclusion

As governments commit unprecedented public resources to decarbonization, the question of where those resources land is as consequential as how large they are. This study examined the allocation of U.S. federal energy and environmental investment across the states during IIJA and IRA implementation.

Allocation tracked population and little else. The population elasticity of roughly 0.70 was stable across every specification, while disaster exposure showed no detectable association under four distinct measurements. Public support for climate policy was positively associated in isolation but did not survive standard demographic controls, and we accordingly draw no conclusion from it.

Because the elasticity is significantly below one, the allocation is regressive in population: smaller jurisdictions receive substantially more per resident. This appears to be an inherited property of formula design rather than a deliberate climate-policy choice, which

is precisely why it merits explicit attention. If public investment is to serve resilience and equity objectives, the criteria that encode those objectives must be built into allocation mechanisms; on this evidence they are not yet visible in the outcomes.

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Renewable energy curtailment and regional electricity integration in South América

BY JOAQUÍN CORVALÁN AZPIAZU

Abstract

This work examines the growing problem of renewable energy curtailment in South America, driven by the rapid expansion of variable renewable energy sources outpacing transmission grid development. Based on regional data, we argue that international power interconnections represent an effective mechanism to reduce curtailment rates. While multilateral integration efforts in the region have faced political and institutional barriers, bilateral interconnection agreements offer a faster and complementary alternative. We analyse the local regulatory framework underlying the Chile-Argentina InterAndes interconnection as a successful case study, identifying key design elements — including opportunistic export mechanisms, marginal-cost pricing, and interruptible trade clauses — that can be replicated by other South American countries without requiring prior regulatory harmonization. We conclude that a progressive network of bilateral connections, complementary to multilateral initiatives, constitutes a pragmatic path toward regional electricity integration and curtailment reduction.

Keywords

Curtailment, Power interconnections, South America, Regional Energy Integration

I. Introduction

The expansion of clean energy capacity has exposed a structural vulnerability: transmission grids have not kept pace with generation growth, giving rise to one of the most pressing challenges in contemporary energy policy — renewable energy curtailment. When generation exceeds grid capacity or demand, system operators are forced to waste electricity that was physically available and environmentally valuable, incurring significant economic losses and undermining the very rationale of the energy transition.

Among the proposed responses — grid expansion, battery storage, and demand response — international power interconnections stand out as a different solution. Interconnections expand the effective geographic and temporal scope within which renewable energy can be consumed, allowing complementary generation profiles across borders to substitute for costly storage or curtailed dispatch. Yet South America's record of regional electricity integration has been uneven: multilateral initiatives have faced persistent political, institutional, and geographic barriers, while bilateral arrangements have proven more tractable.

This work examines the conditions under which bilateral power interconnections can serve as an effective and pragmatic instrument for energy integration and curtailment reduction. Drawing on regional data and a detailed analysis of the regulatory framework governing the Chile–Argentina InterAndes interconnection, we identify a set of replicable legal and operational design elements — including opportunistic export mechanisms, marginal-cost pricing, and interruptible trade clauses — that enabled this arrangement without requiring prior regulatory harmonization. We argue that a progressive network of bilateral connections, built on these principles and pursued in complement to multilateral efforts, represents the most viable path toward regional electricity integration in South America.

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II. Curtailment as a problem and interconnection as one of the possible solutions

There has been a strong emphasis, particularly since the 2015 Paris Agreement, on the significant impact the energy sector has on greenhouse gas emissions. This has led countries to establish roadmaps for transitioning from electricity generation based on fossil fuels to one based on variable renewable energy sources, primarily wind and solar power. Academic[1] sources and international organizations[2] estimate that the energy sector accounts for nearly 75% of GHG emissions.

To deliver the energy produced by power generation sources to consumption points, power transmission grids are needed to carry large amounts of electrical energy at high voltages. That said, the development and growth of renewable energy generation has not necessarily been accompanied by the same growth and expansion of transmission grids. The situation in South America[3] is no exception to this global phenomenon, as the lag in the development and connection of transmission grids is a problem in many electrical systems around the world[4].

One of the problems caused by the lack of transmission infrastructure development is curtailment. Curtailment is defined as the forced reduction of electricity generation—primarily from variable renewable sources (solar, wind)—carried out by the respective electricity system operators, which occurs when generation exceeds demand or grid capacity constraints, resulting in a portion of the energy not being used or dispatched even when it is physically available. Curtailment has negative economic, environmental, and

operational effects[5] . Curtailment of renewable energy, like the global problem of lagging transmission infrastructure development, is a growing concern worldwide[6], and the global acceleration in the expansion of variable renewable energy has been accompanied by an increase in the magnitude and frequency of curtailment[7].

Solutions that have been considered to address curtailment—globally, in academia, and in public policy—include improving and expanding grid infrastructure, developing battery energy storage systems (BESS), and implementing demand response programs[8]. The option of trading curtailment has even been proposed[9]. Furthermore, a potential solution to mitigate curtailment lies in the implementation of power interconnections, an issue we will address in this paper. Indeed, international power system interconnections offer an additional solution for power systems experiencing rising renewable energy penetration[10], and thereby help address curtailment.

III. South American Regional Overview of Transmission and Curtailment

Lartin America has seen strong growth in renewable energy development over the past decade. The share of renewable energy generation in Latin America has risen from 52% in 2015 to 67.7% in 2025[11]. In addition, the past three years have seen a steady increase in non-conventional renewable energy (particularly wind and solar)[12].

The surge in the development of renewable energy projects, in turn, requires an expansion of transmission infrastructure. However, the process of connecting to the grid and obtaining licenses and permits is currently one of the biggest bottlenecks for transmission infrastructure in South America, with transmission grids experiencing high levels of congestion. This is caused, among other things, by the rapid integration of variable renewable energy sources (solar and wind) along with rising electricity demand[13], and consequently, increasing curtailment rates.

OLACDE has released some interesting data regarding curtailment in Latin America for the year 2025. Renewable energy curtailment in the region reached 53,000 GWh in 2024, accounting for nearly 3.2% of total generation. The economic losses associated with this curtailment are estimated at around $7 billion[14].

The cases of Brazil, Argentina, and Chile, South American countries, are of particular interest.

In the case of Brazil, the 2025 OLACDE document notes that, in 2024, curtailment in Brazil reached 10% for wind power and 17% for solar power, totalling 22,284 GWh[15].

In the case of Argentina, we would like to highlight that in October 2025, 64 GWh of curtailment was recorded, and in December of the same year, 54.6 GWh, representing 2.3% of the total potential energy output[16]. In January 2026, 2.8% of solar energy was not dispatched due to transmission grid congestion[17].

The case of Chile is of particular interest, as it has seen a steady increase in curtailment since 2019. According to data from the Chilean National Electricity Coordinator's database in its various Annual Performance Reports[18], the annual curtailment of variable renewable energy is as follows: 2019, 196 GWh; 2020, 251 GWh; 2021, 1,471 GWh; 2023, 2,667 GWh; 2024, 5,909 GWh; 2025, 6,084 GWh.

The question that arises, then, is what role power interconnections play in reducing curtailment in South American countries.

We have already noted that power interconnections are part of the proposed solutions to reduce curtailment, and this is because they expand the scope (geographic diversification of demand) and the timeframe (offset of temporal variability) within which renewable energy can be consumed, with complementary generation profiles allowing a surplus in one area to offset a deficit in another. Furthermore, this effectively results in an expansion of the system's effective size.

It has been demonstrated that curtailment levels decrease when power interconnections are expanded, as one of the various measures or solutions to this phenomenon. In fact, a study published in May 2025 by Hou Jinag, Ling Yao, Jun Qin, and others[19] confirms this finding. The study projected two interconnection scenarios for the year 2050: (i) the least interconnected global scenario is called "Regionally Independent"; and (ii) the most interconnected global scenario is "Global Interconnections." In the latter scenario, "Global Interconnections," the curtailment rate drops by 33.6% compared to the "Regionally Independent" scenario.

A real-world, iconic, and very relevant example is the case of Chile, particularly regarding the SIC-SING power interconnection established in 2017. Although this interconnection is not international in nature, it is evident that the interconnection of the two power systems (Chile's Norte Grande Interconnected System and the Central Interconnected System) reduced curtailment levels[20]: following the interconnection of the systems in Chile, curtailment rates of nearly 14% in 2017 dropped to around 2% in subsequent years[21], reducing curtailment rates by nearly 80% in the Norte Chico region of Chile. The Andes-Cobo interconnection between Chile and Argentina (InterAndes Model), built between 1997 and 1999, but having ceased operations on several occasions, it became operational again, and electricity exchanges resumed in 2022, a resumption that was motivated in part by the goal of reducing curtailment[22].

IV. Electricity integration in South America: Multilateral and bilateral interconnections

We have already noted that the high curtailment rates of renewable energy in South America could be reduced, among other factors, through power interconnections. These can be multilateral and/or bilateral. Let us briefly explore the alternatives.

a) Multilateral interconnections.

In South America, high curtailment rates could be reduced through the consolidation of an interconnected regional system. On the South American continent, there are two main systems that have been promoting regional electricity integration as part of

their objectives for years. One is SINEA and the other is SIESUR. Progress has also been made in the creation of a Regional Andean Electricity Market (MAER).

Currently, according to the latest official data provided by OLACDE in 2024[23], there are nearly 17 operational interconnections in South America, all of them at the binational level, and nearly 15 interconnection projects under study or in development. Despite the significant and valuable efforts and work carried out by these organizations, and others such as OLACDE and the Inter-American Development Bank, among others, for various reasons an interconnected system in a multilateral level has not been formed; rather, energy exchanges have occurred primarily at the bilateral level. This can be explained by many factors.

One of these reasons is geographical: South America is home to the Andes Mountains, and the Amazon—geographical features that make it difficult to coordinate and implement power interconnections in a multilateral level[24].

And the most significant factor, in my view, is politics or geopolitics: unlike, for example, the European continent, which has a mature interconnection system—with nearly 547,000 kilometres of interconnections and 341 cross border interconnections[25]—featuring genuine and robust integration of the various power systems and the consolidation of ENTSO-E (European Network of Transmission System Operators for Electricity), in the European case, regional power integration arose as a necessary consequence of a prior process of trade integration, and of course, political integration. In the South American case, the standardization of local regulations, the creation of common regulatory frameworks, and energy interdependence among neighbouring countries are not viewed with much confidence by political actors in the region, which has hindered progress toward a multilateral interconnection network. A consensus has been reached among the countries of the region that the difficulty of multilateral regional interconnections is more a matter of regulation and regional governance than of technical issues[26].

b) Binational interconnections.

Another way to reduce curtailment rates is through binational interconnections between two countries. In the case of South America, as we have noted, all international interconnections have been established on a bilateral basis. It appears that this is the approach that has been most successful when it comes to international interconnections.

I would like to highlight the successful initiative carried out by Chile and Argentina a few years ago and examine what lessons can be drawn from it.

In November 2022, the power company AES Andes, in conjunction with Chilean and Argentine authorities, announced the start of bidirectional energy trade between Argentina and Chile via the 345kV InterAndes interconnection line, which spans 409 kilometers between the Andes Substation in Chile and the Cobos Substation in Argentina. This interconnection reduces curtailment of variable renewable energy in northern Chile by exporting up to 80 MW from Chile to Argentina, while at night up to 200 MW can be exported from Argentina to Chile.

In order to serve as a guide for other South American countries in establishing a successful interconnection process, this study reviewed the Chilean legislation and sector-specific regulations that enabled this interconnection, specifically the General Electricity Services Law, and the Regulation N° 142/ 2017, setting forth the requirements and procedures applicable to applications for international electricity exchanges, and the specific decree granting authorization to the company AES Andes. The key elements of this binational interconnection mechanism are as follows:

1. Prior government authorization and enabling legislation: Article 82 of the General Electricity Services Law provides that the import or export of electricity may not take place without prior authorization from the Ministry of Energy. This is relevant insofar as (i) it preserves the sovereignty of each State, facilitating domestic political acceptance; (ii) it involves multiple technical agencies in the evaluation of the measure; (iii) it generates a formal administrative act that provides legal certainty to private entities investing in interconnection infrastructure.
2. Two-tier regulatory framework: Regulations establishing the procedure for international energy exchanges and a decree from the Ministry of Energy authorizing specific energy exchanges. No prior regulatory convergence between the two countries or common multilateral regulations are required; only operational compatibility is needed.
3. Opening the door for private companies to operate the exchange: The binational exchange is not limited to state-owned enterprises or intergovernmental agreements; rather, it can be initiated by a private entity. In this specific case, it was initiated by AES Andes, which applied for a permit to export and import electricity between Chile and Argentina.
4. Precise definition of the Border Point: This is intended to keep the electricity systems of Chile and Argentina separate, thereby defining technical and economic responsibilities between the two systems without the need to harmonize the internal regulations of both countries. In the Chilean case, this point is defined as the node of the electricity system located within national territory where measurements of international electricity transactions are taken.
5. Opportunistic exports and curtailment condition: Highly relevant to the goal of reducing curtailment rates in South America, the exchange of electricity between Chile and Argentina will be opportunistic, that is, in the case of exports from Chile to Argentina, it will come solely from surplus energy available at generating units that are in a curtailment condition (Articles 3, 5, and 6 of Decree 134 of 2022, Ministry of Energy). The

curtailment condition is defined as a condition of a generating unit that, despite having variable primary resources, cannot feed part of its energy into the National Electric System due to constraints within that system, such as transmission system congestion, among others. This mechanism is particularly valuable because it allows countries with high penetration of variable renewable energy (solar in northern Chile, wind in southern Argentina, and hydroelectric in Brazil and Colombia) to export their surpluses—which would otherwise be wasted—without compromising domestic supply.

6. Marginal-cost pricing of energy: Energy imports will be treated as energy injections at the border point and priced at marginal cost at that same node for the purpose of including this injection in the balance of energy injections and withdrawals. This option, which replaces the regulation of tariffs by decree or other means, reduces the need for intergovernmental negotiation, allowing real economic signals to prevail.
7. Interruptible nature of trade and safeguarding national energy security: Whether for imports or exports, electricity trade is interruptible in nature. This characteristic is key to securing political acceptance of binational trade in countries where there are concerns or mistrust that electricity integration could compromise domestic supply and security.

This model, which doesn't claim to be the only one, demonstrates that effective binational interconnection does not require extensive regulatory harmonization or multilateral political will, but technical approval or homologation of the systems is required. What it does also require is a clear domestic regulatory framework—independent of each country—that facilitates electricity exchanges while preserving and prioritizing domestic supply; pricing mechanisms based on market signals; and the use of renewable surpluses as a driver of exchange.

Each of these elements can be adopted by South American countries independently, thereby building a network of bilateral connections that, taken together and de facto, over time and progressively—in complement to the efforts of SINEA, SIESUR, Inter-American Development Bank, and OLACDE in implementing public policies aimed at multilateral interconnections, will produce regional electricity integration that reduces the high rates of curtailment of variable renewable energy.

V. Conclusions

Among the available instruments, international power interconnections offer a different mechanism for curtailment reduction — one that expands the effective market for renewable surpluses across geographic and temporal boundaries without requiring the physical storage or grid upgrades that alternative solutions demand. The evidence from the SIC-SING interconnection within Chile, which reduced curtailment rates by nearly 80% in the Norte Chico region following its 2017 commissioning, and from international simulations projecting a 33.6% reduction in curtailment under globally interconnected scenarios, provides empirical grounding for this claim.

Yet the most original contribution of this paper lies not in the identification of interconnections as a solution — that much is established in the literature — but in the analysis of *how* such interconnections can be achieved in a region where multilateral integration has consistently stalled. The Chile–Argentina InterAndes case demonstrates that effective binational electricity trade does not require regulatory harmonization, common multilateral institutions, or deep multilateral political integration. What it requires is a domestic legal framework that preserves national sovereignty, enables private initiative, prices energy at marginal cost, and conditions exports on a verified curtailment state. Each of these elements is independently adoptable by any South American country, without waiting for regional consensus.

This insight has implications for energy policy across the continent. Rather than treating bilateral agreements as a substitute for regional integration, policymakers should recognize them as a viable foundation. A progressive, pragmatic network of bilateral connections — designed along the lines analysed here, and pursued in complement to the ongoing work of SINEA, SIESUR, OLACDE, and Inter-American Development Bank — can produce, in fact, and over time, the regional electricity integration that South America has long sought.

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Integration Without Union: What Europe's Energy Crisis Reveals About the Security Value of Interconnection

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1. Introduction

Between late 2021 and 2023, European electricity infrastructure and institutions were tested under conditions they had not been designed for. A market architecture developed over three decades with efficiency as its primary objective was required to maintain supply, and to keep prices politically acceptable, while the continent's largest external gas supplier withdrew.

The scale of the shock was considerable. The Dutch TTF benchmark reached a record of roughly €342/MWh in August 2022, about fifteen times its pre-crisis average. Because most EU wholesale markets price at the marginal unit, which is frequently gas-fired, the shock was transmitted strongly into electricity prices, and average EU household electricity prices in the second half of 2022 reached the highest level in Eurostat's record. The crisis therefore constitutes a natural stress test of infrastructure and institutions built primarily for efficiency rather than resilience, and it is this test, rather than the price history itself, that the present article examines.

The research question is the following: **under what institutional and infrastructural conditions does electricity-market integration generate security value beyond its ordinary commercial value?** The approach is comparative and architectural rather than econometric. Section 2 introduces a framework that distinguishes three sources of value in cross-border integration and formulates three propositions about their interaction. Sections 3–5 develop each proposition against the European evidence of 2021–2023, selected because it is the largest recent real-world stress test of an integrated electricity architecture under a correlated, politically induced shock. Section 6 applies the same framework to three configurations of integration in the Americas — Central America, the Southern Cone, and the Andean region — which represent institutionally distinct responses to the same design problem. Section 7 discusses the limitations of the analysis. The article does not estimate the causal effect of integration on security outcomes and does not monetise security value; its contribution is a framework for identifying the dimension along which a given regional architecture is deficient.

2. Analytical framework: three sources of value, three propositions

Cross-border electricity infrastructure generates value of at least three analytically distinct kinds. Its **commercial value** consists of price arbitrage and congestion rents, realised continuously under ordinary market conditions. Its **adequacy value** is its contribution to meeting demand under scarcity: the capacity value that adequacy assessments assign to interconnection, realised in tight but foreseeable conditions. Its **resilience (or security) value** is its contribution under rare, correlated, or politically induced disruptions — conditions whose geopolitical and deliberately induced character may be incompletely represented in conventional adequacy scenarios.

The adequacy literature is extensive and increasingly sophisticated. Probabilistic assessment based on Monte Carlo methods, climate years, and correlated outages is now standard practice, and its remaining challenges — multi-dimensional uncertainty, correlation, market design, and network representation — are well documented (Tillmanns, Schöttler & Praktiknjo, 2026). Reviews of current practice locate the stress-testing of high-impact, low-probability events at the boundary between adequacy assessment and resilience planning (Mantegna et al., 2026), and surveys of planning practice find no systematic treatment of extreme-event costs or resilience benefits in most planning analyses (Carvallo et al., 2023). Valuing the capacity contribution of interconnectors is recognised as particularly difficult, given bidirectionality and the possibility that stress in neighbouring systems coincides (Tindemans, Woolf & Strbac, 2019). The claim developed in this article is therefore not that security is absent from existing frameworks, but that the third category of value — value realised under correlated, low-probability conditions — remains the most weakly connected to the appraisal and remuneration mechanisms that determine which infrastructure is actually built.

Three propositions follow from this distinction:

P1. The resilience value of interconnection is realised in the tail of the distribution and is therefore at risk of systematic under-weighting in commercially anchored appraisal.

P2. Physical integration and institutional coordination are complements: interconnection delivers its full security value only where a specific, identifiable set of cross-border rules exists, and physical links without those rules can transmit the costs of national interventions as readily as they transmit assistance.

P3. Temporal buffers — storage, and more generally dispatchable reserves and supply diversity — do not resolve structural shortage; they extend the response window within which institutional mechanisms can act.

Taken together, the propositions imply that the security value of integration depends jointly on physical

connectivity, institutional coordination, and temporal buffers, and that these three dimensions interact rather than add.

3. Proposition one: resilience value and investment appraisal

In commercially anchored appraisal, an interconnector is valued primarily through the price differentials it is expected to arbitrage. Such appraisal weights the states of the world in proportion to their probability, whereas the resilience value of interconnection is concentrated in low-probability states. In a crisis, the relevant value is not the average price spread but an option: the ability, on the small number of days when a system is short, to import power that would not be available at any domestic price.

A distinction is necessary at this point. Regulated transmission planning in Europe formally incorporates security-of-supply and socio-economic welfare criteria into project assessment, and careful evaluations of existing interconnectors do quantify a security-of-supply component within social value (Newbery, Gissey, Guo & Dodds, 2019). The appraisal gap identified in P1 therefore concerns, first, merchant and commercially anchored investment decisions, in which expected congestion rents dominate, and second, the question of how even regulated cost–benefit frameworks weight low-probability, correlated disruptions relative to routine scarcity. On the latter point the evidence is direct. Conventional grid-investment cost–benefit analysis focuses on expected values and does not explicitly account for the uncertainties associated with high-impact, low-probability events (Sperstad, Kjølle & Norum, 2021), and the reliability benefits of transmission are poorly captured by changes in expected congestion rents (Lamadrid, Maneevitjit & Mount, 2016). Empirical analysis of US wholesale markets over 2012–2022 quantifies the concentration directly: for the majority of studied links, 5% of hours accounted for at least 45% of the total market value of transmission, with those peak periods driven primarily by unforeseen changes in conditions (Kemp, Millstein, Gorman, Jeong & Wiser, 2025). Recent syntheses of US national transmission studies point in the same direction, finding high benefit–cost ratios that conventional planning practice does not fully capture (Mai et al., 2026). Appraisal built on expected spreads therefore creates a systematic risk that interconnection will be under-provided relative to what a security-informed assessment would support. This is a risk rather than a demonstrated outcome, since establishing actual under-provision would require a counterfactual welfare benchmark that this article does not attempt to construct.

The French experience of 2022 illustrates the mechanism. Following the discovery of stress-corrosion cracking, the availability of the French nuclear fleet averaged 54% across 2022, compared with 73% in 2015–2019, and reached a low of 21.7 GW on 28 August 2022, with nearly 65% of the fleet offline. Annual nuclear output fell to 279 TWh from 360.7 TWh a year earlier, while drought reduced hydro output by nearly 21%. As a result, France became a net importer of electricity for the first time since 1980, with a net import balance of 16.5 TWh and imports peaking at a record 15.8 GW in November (RTE, 2023). A less interconnected France would have faced the same fleet failure with correspondingly less margin between scarcity and involuntary curtailment. The case is an illustration rather than a proof — a full counterfactual would require modelling which domestic resources could have substituted, and at what cost — but the direction and approximate magnitude of the option that interconnection provided are not seriously in doubt.

The methodological implication constitutes the substance of P1. If resilience value is real but concentrated in states of the world that commercial appraisal down-weights, it needs to be measured deliberately, with instruments designed for that purpose. The risk-and-uncertainty perspective on electricity markets developed in the author's earlier work (Thlon, Brożek & Thlon, 2024) points in this direction, and the construction of operational measures of the tail component of security value forms part of the research agenda outlined in the concluding section. What the market does not price, the planner must — provided the planner has an instrument with which to price it.

4. Proposition two: physical integration and institutional coordination

In policy debate, market integration and security of supply are often presented as competing objectives. The European evidence suggests that they are better understood as complements, subject to conditions that can be stated concretely. “Institutional coordination” is used in this article to mean a specific, enumerable set of arrangements: common capacity-allocation and congestion-management rules; day-ahead and intraday market coupling; coordinated redispatch; balancing cooperation; emergency assistance and solidarity procedures; data-exchange and settlement rules; and arrangements for sharing the costs of national interventions that spill across borders. Where this apparatus exists, interconnection functions as a form of mutual insurance. Where physical links exist without it, the same links transmit distortions.

That uncoordinated national measures generate material cross-border effects in coupled systems is well established. Unilateral capacity mechanisms produce negative externalities for neighbouring consumers and producers (Meyer & Gore, 2015; Mastropietro, Rodilla & Batlle, 2015). Price interventions propagate through interconnectors: Britain's unilateral Carbon Price Support raised French wholesale prices by 3.5% and Dutch prices by 2.8%, with a measurable deadweight loss from distorted trade (Guo & Newbery, 2023). Agent-based analysis of nationally implemented CO_2 price floors and ceilings in coupled markets finds the same qualitative pattern of cross-border cost transmission (Richstein, Chappin & de Vries, 2014).[1]

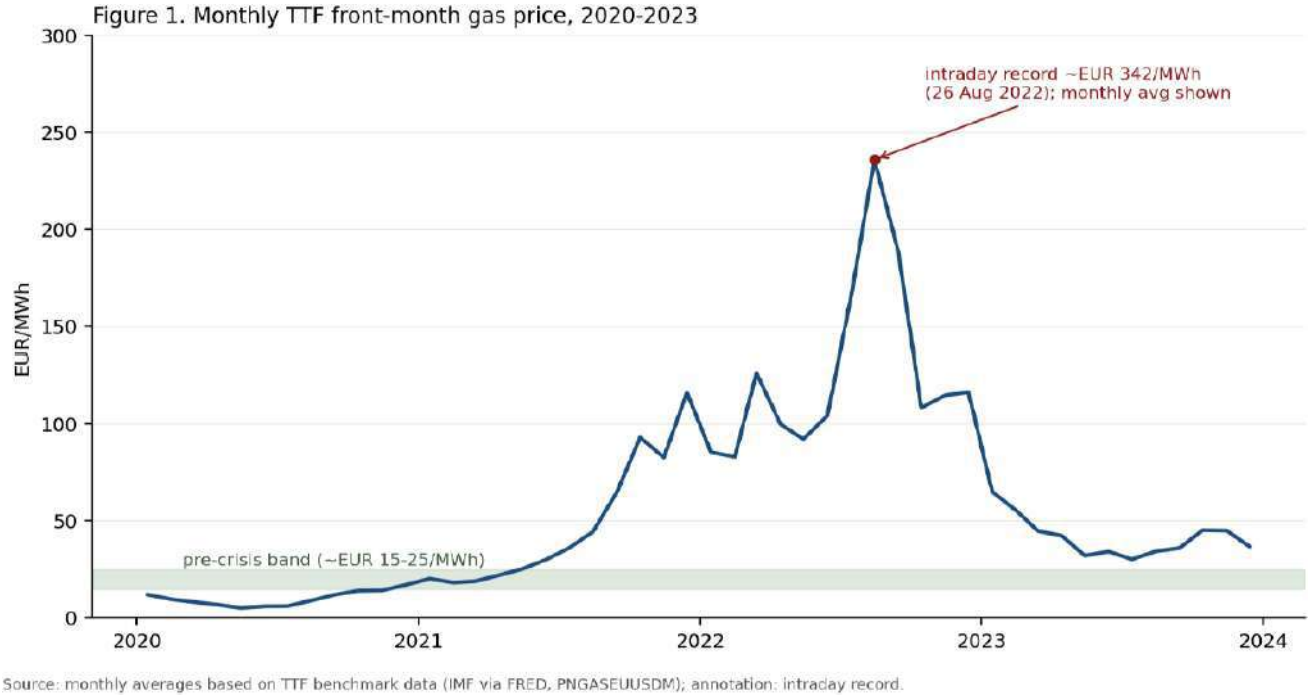

Figure 1: Monthly TTF front-month gas price, €/MWh, 2020–2023. Source: TTF benchmark data (IMF via FRED, PNGASEUUSDM); shaded band: pre-crisis range; annotation: intraday record of 26 August 2022.

The Iberian episode of 2022–2023 serves as the diagnostic case. Spain and Portugal, arguing that their weak interconnection with the rest of the continent made them an "energy island", obtained approval to cap the price of gas used in power generation from June 2022. On its own terms the mechanism performed as intended: it benefited the roughly 40% of Spanish households and SMEs on regulated tariffs, at an initially estimated cost of €6.3 billion (Corbeau, Farfan & Orozco, 2023), and counterfactual simulation indicates that the subsidy reduced Iberian day-ahead electricity prices by 35.3% (Lou, Pollitt, Robinson & Arcos-Vargas, 2026). The instructive element, however, lies in the cross-border side-effects. By lowering the marginal cost of Spanish gas plants, the subsidy made Iberian power cheaper relative to France, and the interconnectors carried the subsidised power outward. Gas-for-power demand rose by 25% in Iberia relative to the no-intervention counterfactual — and by 3.2% at the level of the EU as a whole — with roughly one quarter of that effect attributable to increased electricity exports to France and Morocco (Lou et al., 2026). The Iberian exception was an understandable response to an acute emergency, shaped by the specific features of the peninsula's position. For precisely that reason, it illustrates what can happen when cross-border physical flows extend beyond the institutional arrangements governing the distribution of intervention costs. In this sense, an emergency price cap can be read as the fiscal trace of a missing institution — a reading, it should be stressed, rather than a general law.

A complementary empirical strand concerns price behaviour across internal borders. Persistent price divergences between coupled or neighbouring markets may provide evidence of incomplete integration or institutional friction, but only once structural differences in generation mix, taxation, network tariffs, and retail regulation have been controlled for, since all of these produce divergence without any institutional failure. The author's analysis of the evolution and determinants of household electricity price gaps between Poland and selected EU countries over 2010–2025 addresses precisely this problem, separating structural and policy determinants of retail price divergence (Thlon, 2026). For present purposes, a modest conclusion is sufficient: the returns to building interconnection and the returns to building the rules that govern flows across it are complementary, and a region that invests in one without the other should not expect the full security benefit of either.

5. Proposition three: temporal buffers and the response window

If interconnection and its governing rules form the structural layer of security, temporal buffers operate on the timescale of a single season. The Gas Storage Regulation of June 2022 imposed a binding 90% filling target by 1 November of each year (80% for 2022 itself), and the EU reached a filling level of 94.9% by 1 November 2022; full EU storage holds roughly one third of annual gas consumption (European Commission, 2022, 2023). In parallel, coordinated demand reduction contributed a 17.7% fall in gas consumption between August 2022 and March 2023, while record LNG imports replaced pipeline volumes (European Commission, 2023).

The analytical content of P3 lies in the mechanism, which can be summarised as: shock → buffer drawdown → response window → institutional and market adaptation. The buffer does not remove the shock; it converts an instantaneous shortfall into a finite window. What occurs within that window is the substance of the proposition. Alternative supplies are contracted and delivered, as with LNG cargoes redirected over a period of weeks; imports are scaled through existing interconnection; redispatch and balancing cooperation reallocate existing resources; demand response and administrative demand reduction are activated; emergency and solidarity procedures are triggered; and, where necessary, new rules are legislated, the storage regulation itself being an example. Each of these processes takes days to months. A system whose buffers are exhausted before these mechanisms engage faces the shock directly; a system whose buffers outlast the response time of its institutions avoids confronting the full shortfall before adaptation mechanisms take effect. Buffer capacity and institutional response speed are therefore functionally linked: slower institutional response increases the buffer requirement, while larger buffers relax the required response speed. It is for this reason that P3 belongs within the same framework as P2 rather than alongside it as a separate consideration.

One caution is necessary when transferring this proposition across the Atlantic. The European crisis was a gas shock transmitted into electricity, and its characteristic buffer was gas storage. Latin American systems face shocks of a different physical nature — above all hydrological drought, alongside transmission constraints, generation adequacy, and fuel logistics. The category that transfers is therefore not gas storage but **dispatchable buffers and supply diversity**: hydro reservoirs, which are the region's dominant and climate-exposed storage asset, fuel inventories, reserve thermal capacity, batteries, and access to LNG. The functional question is the same for any system — how long does the buffer hold, relative to how quickly the institutions respond? — even where the physical form of the buffer differs entirely.

6. Application to the Americas: three configurations, one test

Applied to the Western Hemisphere, the framework yields a reading that differs from the common observation that the Americas lag behind Europe. The regions of the hemisphere have answered the integration question in different ways, and each configuration is deficient along a different dimension. Measurement traditions exist to support such a comparison: multidimensional energy-security indices have been developed specifically for Latin American and Caribbean power systems (Fuentes, Villafafila-Robles, Rull-Duran & Galceran-Arellano, 2021), building on the broader multidimensional conceptualisation and measurement of energy security (Sovacool & Mukherjee, 2011) and on quantitative approaches to its geopolitical dimension (Bompard et al., 2017); frameworks for measuring and valuing resilience itself are reviewed in Leddy et al. (2023). The framework generates three observable diagnostics: whether the binding constraint lies in physical capacity, in institutional coordination, or in the duration of available buffers. Table 1 applies this test to each configuration.

Central America provides a joint test of P1 and P2, and from an unexpected direction. Its regional market is not an incomplete version of the European one but a deliberate alternative: a supranational market established by the 1998 Framework Treaty and resting on autonomous regional institutions — a regulator (CRIE), a system operator (EOR), and a grid-owning company (EPR) — designed so that governments retain independent management of their national systems. This is integration without union. Several core elements of the institutional apparatus described in Section 4 already exist; the binding constraint is physical capacity, which the second-circuit investment is only now addressing. The region thus presents the mirror image of the Iberian problem, with rules ahead of physical capacity rather than behind it. This is arguably the less problematic order in which to be deficient, since adding transfer capacity to a functioning rulebook is easier than retrofitting a rulebook onto contested flows.

The Southern Cone provides a test of P2. Exchange has grown rapidly — South American cross-border trade rose by 28% in 2023 to 39.8 TWh, of which 95.3% took place in this subregion, while covering only 3.7% of continental demand (OLADE, 2024) — yet the multilateral institutional layer remains thin and recent. Under the framework, this is the configuration exposed to Iberian-type spillover risk. The concern is not that an identical price cap will be replicated, but that uncoordinated national interventions will impose costs across borders in the absence of a compensation mechanism, in line with the pattern documented in the coupled-market literature cited above.

The Andean region provides a test of P3, and has in effect already run the experiment. Regional market rules date only from May 2024; interconnection is thin, with Ecuador covering 4.4% of demand through imports from Colombia and Peru; and the dominant buffer, hydro storage, is precisely the asset that drought degrades — OLADE itself notes that episodes of joint hydrological scarcity, such as the recent one affecting Colombia and Ecuador, raise generation costs and can end in rationing, and identifies international interconnection as one of the responses (OLADE, 2024). Ecuador's electricity rationing in 2024 is the observable outcome, and sector assessments have argued that deeper regional integration could have materially reduced the need for rationing. The episode is consistent with all three vulnerabilities operating simultaneously: a thin interconnection option (P1), a nascent institutional layer (P2), and a drought-degraded buffer exhausted faster than institutions could respond (P3).

Chile enters the analysis not as a fourth case but as a forward-looking implication. Situated between the Andean systems and the Southern Cone, a Chile connected northward could link the two configurations

Table 1: Three configurations of electricity integration in the Americas, assessed against the framework

Dimension	Central America (SIEPAC / MER)	Southern Cone	Andean region (incl. Ecuador)
Physical interconnection	Regional line operational for over a decade; 300 MW design capacity not achieved along full length; second circuit (US$46.4m, CABEI/EPR) to raise minimum exchange capacity by 300 MW on the Honduras–Nicaragua and Nicaragua–Costa Rica sections	Material and growing bilateral ties; exchanges concentrated here (95.3% of continental trade)	Thin; dependence emerging (Ecuador met 4.4% of demand through imports)
Market coupling / trading rules	Operating supranational market (MER) under the 1998 Framework Treaty, with autonomous regional institutions (CRIE, EOR, EPR)	Largely bilateral contracts; SIESUR relaunched only in 2018	Regional rules (MAER) adopted only in 2024
Emergency coordination & cost-sharing	Regional dispatch and settlement exist; cost-sharing untested at scale	Weak multilateral layer	Nascent
Dispatchable buffers / supply diversity	Modest; regional trade is itself the buffer	Hydro-dominated with thermal reserve; Argentina imports ~10% of demand	Hydro-dominated, drought-exposed
Binding constraint	**Physical connectivity**	**Institutional coordination**	**Both, plus buffers**
Security implication	P1: option value known, wire is the limit	P2: wires ahead of rules — Iberian-type spillover risk	P3: buffer–response mismatch under drought stress

Sources: OLADE (2024) for South American exchange volumes, shares, demand coverage, and the SIESUR initiative; CABEI (2025) for the second SIEPAC circuit; World Bank (2011) and the MER Framework Treaty for the Central American institutional structure; Comunidad Andina (2024) for the MAER operating rules.

both physically and institutionally, a role for which its market-design tradition provides credibility. Specifying that role — the transmission investments, the legal instruments, the sequencing — would require a study of its own and is not attempted here; the framework identifies the position rather than the project.

7. Limitations

Four limitations bound the conclusions. First, the European crisis was in important respects sui generis — a deliberately induced supplier withdrawal acting on a highly gas-exposed price-formation mechanism — and transferring its lessons does not imply equivalence between shocks. Second, the analysis compares architectures; it does not estimate the causal effect of integration on any security outcome, and the case assignments in Table 1 are judgements rather than measurements. Third, "security value" is used as an organising concept and is not monetised; monetisation would require region-specific estimates of the value of lost load and of shock probabilities, which lie beyond the scope of this article. Fourth, the American systems are heterogeneous along dimensions — hydrology, market maturity, political economy — that a three-configuration comparison necessarily compresses.

8. Conclusions

The European crisis does not demonstrate that integration is an unqualified good; it identifies the conditions under which integration produces security. Three conclusions appear transferable. First, the resilience value of interconnection is concentrated in the tail of the distribution and therefore requires deliberate measurement of that tail component, connected to what is actually remunerated and built (P1). Second, physical links and cross-border rules are complements, and the institutional apparatus enumerated in Section 4 — above all, cost-sharing arrangements for cross-border spillovers — is what converts physical links into mutual insurance rather than channels of distortion (P2). Third, buffers, understood broadly as dispatchable resources and supply diversity rather than gas storage alone, are valuable in proportion to the institutional response time they cover (P3).

One feature of the European experience transfers poorly, and Central America demonstrates why. The transfer of governance authority that accompanied European market integration is not a precondition of the security gains; the MER captures important institutional elements associated with those gains while leaving national system management sovereign. For a hemisphere in which sovereignty remains a live constraint on integration, this may be the most useful single observation the comparison yields. It also points to a research agenda, to which the author intends to contribute, concerning the minimum institutional arrangements sufficient for a given level of security benefit.

The practical test for a regulator or system operator follows directly from the framework: what is the interconnection of the system worth in the tail of the distribution, measured outside the arbitrage case; which of the enumerated cross-border rules exist, and which are missing; and how long do the available buffers hold, relative to the time the institutions need to respond. Europe answered these questions in the course of an emergency. The Americas are still in a position to answer them in advance.

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Footnote

[1]On related mechanisms — free-riding and capacity leakage under heterogeneous adequacy policies, and under-procurement risks when nationally financed capacity markets share regional scarcity — see Cepeda & Finon (2011) and Menegatti & Meeus (2026). At the system level, connectedness analysis attributes roughly three-quarters of the forecast-error variance in national wholesale electricity prices to cross-border volatility spillovers (Cevik & Zhao, 2026).

Brazil's Critical Minerals Industry and Its Trade

BY ADITI SARKAR

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Beneath the lush Amazon rainforests, wetlands, and savanna of Brazil lie vast reserves of critical minerals. It has one-fourth of global graphite reserves and around 15% of global nickel and manganese reserves. It also has the largest share of niobium on the planet. Part of the reserves remain untapped, leaving immense business potential. The table below shows the mineral reserves and production in the country [7].

Mineral	Production	Reserves
Niobium	90.36%	94.12%
Graphite	4.56%	26.42%
Rare earth elements	0.02%	19.09%
Manganese	3.10%	14.21%
Nickel	2.47%	12.31%
Lithium	2.72%	1.39%

Source: Center on Global Energy Policy [7]

Critical minerals are required for clean technology. If we are to wean away from dependency on fossil fuels, we will need to produce more renewable energy, and renewable energy requires critical minerals to work. Countries are now exploring and mining for these minerals.

Among these countries, China has the most substantial control over the critical mineral economy in the world. It has trading relationships with countries that have these minerals and they refine the minerals in China. The vast majority of the refineries are located in China giving them a stronghold over it. Brazil is another major country with reserves of these resources. It has an old trading partnership with China. With the US also showing interest in these minerals, they will be vying for a partnership with Brazil too. Before analyzing the partnerships, we need to evaluate Brazil's own policies on mining investment.

Brazilian Policies

While Brazil is open to trade with other countries and foreign investment, it, however, has restrictions on activities within the country's borders. One of the regulations is using a local workforce and having majority Brazilian ownership. But this has not deterred Foreign Direct Investment (FDI) from flowing into the country. In 2019, it was the world's sixth largest destination for FDI with $72 billion in inflows [1].

This open investment climate underpins deeper government efforts to court foreign capital. The Brazilian government is tapping into its abundant resources by attracting foreign investment tax benefits and reduced costs of financing. However, high mining taxes and the complexity of the overall tax environment spread across different jurisdictions remain an obstacle for foreign investors. Further, the government is helping create a national mining industry to attract foreign investors with a specific strategic plan for critical minerals. It is planning to restructure the National Mining Agency and process the 70,000 licenses awaiting approvals. On top of this, the national geology department created a division on critical minerals that streamlines approval for projects on lithium and rare earth minerals. It is also advertising its own resources on the global platform and is participating in global discourse on critical minerals. The government has dedicated $60 billion to modernize the industrial sector by increasing autonomy and developing clean energy sources. It has also directed $61 million to mining R&D along with $3.8 billion in tax incentives for companies investing in electric vehicles (EV). The Brazilian National Development Bank and the Ministry of Mines and Energy collaborated to create a new investment fund worth $200 million to attract investors to mineral exploration projects in support of energy transition and fertilizer supplier chains [7]. With this domestic framework in place, Brazil's next challenge lies in balancing the competing overtures of its two largest partners: the United States and China.

Brazil and US

Brazil exports the majority of its value-added manufactured goods to the US, and the US is the largest source of foreign direct investment, with $208 billion, in Brazil in 2023. The US is also the second-largest importer of Brazilian minerals with $13 billion right after China with $23 billion worth of mineral trade in 2023. But after the current administration has imposed tariffs on trade, their relationship has soured slightly. The Brazilian government has become skeptical of the US outreach on its mining sector even though they actually benefit from US International Development Finance Corporation initiatives. The Brazilian government is even rumored to block the sale of Serra Verde to Rare Earth which was announced in April. Further, the US share of Brazilian exports dropped by nearly 13% in first half of 2026 compared to first half of 2025 while exports to China increased by 22% year on year [8]. This growing friction with Washington has coincided with deepening ties to Beijing.

Brazil and China

China has been Brazil's largest trading partner since 2009, buying Brazilian soybeans, iron ore, and crude oil. With growing trade, they started using their local currencies, bypassing the US dollar [8]. China is also the largest buyer of Brazilian minerals, buying around $20 billion of iron ore and $3 billion of other minerals in 2023. BYD, a Chinese electric vehicle maker, is going

to have the largest industrial hub outside of China in Brazil with over $1 billion of investment. Further, two Chinese chemical lithium companies, Chengxin Lithium Group and Yahua Industrial Group, announced they will be funding a Brazilian development project [7]. Further, a Chinese mining company, CMOC, landed a $1 billion deal to assume full ownership of Equinox Gold Corp's operations in Brazil [4]. China has the upper hand in critical mineral processing, having control of 90% of global processing. Brazil is also trying to build its own processing facilities [6].

Environmental Consequences

This mineral race, however, is not without cost. Being an environmentalist at heart, I would be remiss if I did not add a section about the environmental consequences of mining minerals. Brazil has six biomes: 1. Amazon rainforests, 2. Atlantic Forest, 3. Semi-arid Caatinga, 4. Tropical savanna Cerrado, 5. Temperate grassland Pampa, and 6. World's largest floodplain, Pantanal [5].

The diverse ecosystems are home to 10-15% of all known species on Earth [4]. Moreover, the Amazon rainforest is known to be a carbon sink and is important in moderating global warming [3]. Mining minerals will create negative externalities for these ecosystems. 30% of the critical minerals are in the Amazon region. This will require a partnership and open dialogue between the mining companies, the environmentalists, the government, and the indigenous inhabitants of the region. Brazil is expanding its geological mapping (which encompasses 27% of the country currently) to ensure strategic mining and reduce extensive exploratory drilling. This will aid in containing environmental destruction to certain regions. Further, Brazil has to work on minimizing the impacts of tailing dams. Tailing dams are created to store byproduct waste and water from the mineral extraction process. In 2019, the collapse of a tailing dam led to 270 deaths and adverse environmental impacts. All these negative externalities have to be considered while planning mining for minerals [7]. These trade-offs will shape how Brazil converts its mineral wealth into lasting economic gains.

Conclusion

Brazil is poised to become one of the largest producers of critical minerals in the world. To achieve that goal, it is developing strategic relationships with both China and the US. Of late, due to tariffs imposed by the current US government, Brazil has been pushed more towards developing trade relations with China. However, Brazil is refusing to choose sides between the US and China. It has remained neutral so far, with trade and investment still going on with both countries. On one hand, Serra Verde, which historically shipped materials to China, has now signed a 15-year supply agreement with the US backed by the US government and private investors. Further, mining companies like Viridis and others are in talks with the US International Development Finance Corp for investment opportunities. On the other hand, Beijing is also heavily investing in Brazil's mining sector. BYD and other mining companies are investing in Brazil as well. Brazil does not want to become merely an exporter of raw materials. It wants foreign investors to invest in the country and help build jobs. In that respect, it does not want to be partial to any one country [6].

As Brazil continues to grow in this sector, it has to be mindful of the environmental ramifications. The different stakeholders have to work together to devise plans on strategic and effective mining which will minimize environmental destruction. Further, they should also pay attention to better waste disposal of toxic waste arising from mining.

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Beyond the Value of Lost Load: Enabling Customers to Express Their Value of Reliability Through Participation in Wholesale Electricity Markets

BY JULIA FRAYER AND JAVIER A. MAQUIEYRA

Julia Frayer & Javier A. Maquieyra | London Economics International LLC | August 2026

Abstract

Electricity markets have traditionally represented customers' valuation of reliability through the value of lost load ("VoLL"), an estimate of the economic harm caused by involuntary outages. That framework was developed for a largely one-sided market in which generation supplied reliability and demand remained passive until emergency curtailment. Digital controls, distributed generation, batteries and flexible industrial processes are changing that premise. Customers can increasingly reduce consumption, shift demand or export stored electricity in response to prices. This article argues that, once demand can actively provide reliability, VoLL is no longer the only economically relevant measure. Markets should also recognize the price at which customers voluntarily exchange electricity consumption for flexibility - a revealed willingness to participate. Using ERCOT as a case study, the article illustrates the distinction through a production-cost simulation of a hypothetical aggregation of residential rooftop solar paired with two-hour batteries. A 1.2 GW aggregation, representing roughly 1% of projected 2030 peak demand, is dispatched only when wholesale electricity prices exceed $200/MWh in the real-time energy market. The modeling reveals energy market savings ranging from $151 million to $672 million per year, depending on the pattern of forced outages of power plants. These results are based on normalized weather conditions. These results do not imply that distributed batteries can replace conventional generation investments. They show instead that modest, strategically dispatched demand-side participation can reduce the costs of electricity, without undermining significantly the signal for investment in infrastructure in the longer term. The policy challenge is therefore to move from one-sided reliability procurement toward two-sided market designs in which supply- and demand-side resources compete on comparable terms.

Keywords

value of lost load, demand response, two-sided markets, distributed energy resources, virtual power plants, ERCOT, reliability

1. Introduction

Reliability is a foundational attribute of an electricity system, but it is not costless. Additional generation, transmission, fuel security, reserves and system controls can reduce the probability and consequences of shortage, yet each additional increment of protection requires resources that customers ultimately fund. Electricity-market design therefore confronts an economic question as well as an engineering one: how much reliability should the system procure, and which resources should provide it?

For decades, the value of lost load has provided the conventional economic answer. VoLL expresses the cost of electricity that consumers wish to use but cannot receive during an involuntary interruption, generally in dollars per megawatt-hour of unserved energy. It is used in reliability planning, cost-benefit analysis, scarcity pricing and, directly or indirectly, in the calibration of administrative market mechanisms. The attraction is straightforward: if the expected cost of an outage exceeds the cost of avoiding it, an additional reliability investment appears economically justified.

Yet the simplicity of a single VoLL parameter conceals substantial heterogeneity. Outage costs differ by customer class, duration, time, notice, weather, access to backup supply and the portion of consumption interrupted. Recent reviews emphasize that VoLL is multidimensional and that estimates vary materially across methods and contexts (Gorman, 2022; Ovaere et al., 2019). International studies similarly produce wide ranges across residential, commercial and industrial customers. Nevertheless, operational rules and regulatory assessments often compress those differences into one headline value.

A second limitation is becoming more consequential. VoLL was developed for a system in which consumers were largely passive: generators offered supply, system operators dispatched resources, and customers received the energy and paid the resulting price. If supply became insufficient, the system operator would take action that could result in manual load shed or involuntary curtailment of certain customers. In such a setting with inelastic customers, the market could not observe each customer's marginal valuation of electricity in real-time, so an administratively estimated outage cost served as a proxy.

That institutional premise is changing. Smart thermostats, automated industrial controls, electric vehicles, distributed generation and battery storage allow customers to alter their consumption of electricity close to or in real-time, in response to price signals and/or system conditions. Aggregators can combine thousands of small resources into a dispatchable portfolio. FERC Order No. 2222, issued in September 2020, further spurred this transition by directing organized U.S.

wholesale markets to remove barriers to distributed energy resource aggregations, thereby allowing them to compete in energy, capacity and ancillary-service markets alongside conventional resources (FERC, 2020).

This article advances a simple proposition: VoLL remains relevant for involuntary outage risk, but it should not be treated as the sole measure of customers' willingness to participate in the wholesale market and voluntarily curtail their consumption of electricity when supply adequacy issues arise. A different economic decision is involved when a household, commercial facility or industrial plant voluntarily reduces consumption or exports stored energy. That decision can reveal a customer's reservation price for participation, and that price may be very different from the welfare loss associated with being disconnected without choice.

Behavioral economics provides further support for this distinction. Loss aversion implies that individuals tend to place greater weight on avoiding a loss than on obtaining a commensurate gain (Kahneman and Tversky, 1979). An involuntary outage is experienced as a loss of an expected service. A voluntary response to a high price is a choice among alternatives: maintain consumption, defer an activity, adjust a process, or sell stored energy. The framing, degree of control and portion of load affected differ. It is therefore plausible that customers would require a much lower payment to curtail a discretionary component of demand than the compensation implied by losing all electricity services without notice.

We can also measure the impact that such voluntary participation can have on the market. ERCOT provides a useful ecosystem for analyzing the consequences. In February 2021, Winter Storm Uri demonstrated the extreme economic and social consequences of widespread supply inadequacy event and manual load shed. The event motivated substantial discussions around wholesale electricity market reforms, legislative changes to certain retail arrangements, and also a more focused monitoring of market signals for infrastructure investment in Texas. As of the writing of this paper, ERCOT is experiencing a boom in renewable generation and energy storage investment, as well as rapid growth in large flexible loads. Despite the addition of new resources, there is an overarching concern that load growth may outstrip investment trends in supply-side resources. The situation in ERCOT therefore combines an urgent reliability problem with emerging opportunities for active demand-side participation.

The article proceeds in five steps. Section 2 reviews the economic role and limitations of VoLL. Section 3 develops a conceptual framework for modernizing wholesale electricity markets into true two-sided markets. Section 4 describes the analytical framework for testing a hypothetical aggregated residential solar-plus-storage demand response resource on the ERCOT wholesale electricity market using state of the art electricity market simulations. Section 5 presents the modeled results from the simulation. Section 6 discusses policy implications, limitations and priorities for future research.

2. The Economics of Reliability and the Limits of a Single VoLL

The economic logic of VoLL begins with the tradeoff between the cost of reliability and the expected cost of interruption. In a stylized planning problem, an efficient level of reliability is reached when the marginal cost of additional protection equals the expected marginal benefit from avoided unserved energy. VoLL converts that avoided harm into a common monetary unit. This makes the metric potentially useful for investment planning (generation and transmission), supply adequacy studies, and emergency operating decisions.

Historically, with conventional technology and common structures of competitive electricity markets, retail customers do not observe or respond to real-time wholesale electricity prices. Joskow and Tirole (2007) show that price-insensitive demand, administrative price caps, non-price rationing and reserve requirements interact with investment incentives and reliability outcomes. Where customers cannot select service quality or respond to scarcity, system operators necessarily make centralized choices on their behalf. VoLL is then used to approximate the welfare cost of those choices.

Three issues limit the precision of this approximation. First, outage costs are heterogeneous:

- residential customers may lose comfort, food, communications or medical support;
- commercial customers may lose sales and data;
- industrial customers may suffer interrupted production, equipment damage or costly restart processes.

The relevant cost also varies with duration and timing. A one-hour outage on a mild weekend is not equivalent to a multi-day outage during extreme conditions (like very cold weather that put lives at risk during Storm Uri).

Second, the method of estimation matters. Stated-preference surveys typically ask customers what they would pay to avoid an outage or accept as compensation for an interruption. Production-function approaches infer the economic losses associated with disrupted production, while revealed-preference approaches examine expenditures on backup generation, batteries or other investments made to protect against interruptions. Although these approaches capture different dimensions of outage costs and are subject to different biases, conventional applications share an important feature: they are generally framed around the consequences of, or efforts to avoid, an involuntary interruption of electricity service. They are therefore not necessarily well suited to estimating the price at which customers would voluntarily reduce consumption when given a choice.

Third, VoLL is used for several distinct policy purposes. Gorman (2022) distinguishes centralized cost-benefit analysis for reliability-enhancing infrastructure from decentralized rationing decisions during shortage. A single number may be a practical simplification for

Market	Installed Capacity (MW)	Latest VoLL Study	Headline VoLL (Reported cur.)	Headline VoLL (2024 US$)	VoLL Range by Customer Class (2024 US$) – Lowest/Highest
US ERCOT	170,720	2024	$35,685/MWh	$35,685/MWh	•Residential: $3,964/MWh
	(2025)				•Small C&I: $666,907/MWh
US MISO	203,000	2024	$35,000/MWh	$35,000/MWh	•Residential: $4,337/MWh
	(2025)				•Small C&I: $80,965/MWh
Great Britain	111,100	2025	£23,627/MWh	$30,370/MWh	•Non-residential: $22,422/MWh
	(2025)				•Residential: $42,716/MWh
Australia NEM	68,187	2024	A$30,000/MWh	$19,791/MWh	•Agriculture: $14,678/MWh
	(2025)				•Residential: $27,364/MWh
Italy	137,600	2021	€20,000/MWh	$27,390/MWh	•Residential: $14,174/MWh
	(2024)				•Tertiary: $37,250/MWh
Spain	142,558	2023	€22,879/MWh	$25,478/MWh	•Industrial: $25,478/MWh
	(2025)				•Residential: $27,434/MWh
Chile	37,834	2025	$10,754/MWh	$10,478/MWh	•Regulated C&I: $589/MWh
	(2025)				•Unreg. Industrial: $16,352/MWh

Figure 1: Headline VoLL estimates and customer-class variation across selected electricity markets
Note: For comparability, the presentation converted non-U.S. headline values to 2024 U.S. dollars using Federal Reserve exchange rates and the U.S. Bureau of Labor Statistics Consumer Price Index (Federal Reserve; U.S. Bureau of Labor Statistics).
Sources: ERCOT (2024b); MISO (2024); ENA (2026); AER (2024); ARERA (2020); MITECO (2019); CNE (2026).

planning or emergency operations, but it is much less satisfactory as a rule for allocating scarce electricity among heterogeneous consumers. Dynamic prices and demand-response programs allow customers to self-select, reducing reliance on administrative assumptions about whose consumption is most valuable.

The distinction is particularly important because headline VoLL estimates often exceed prices observed in actual wholesale markets. Recent VoLL studies across ERCOT, MISO, Great Britain, Australia, Italy, Spain, and Chile show substantial variation both across markets and across customer classes. As shown in Figure 1, headline VoLL estimates are generally far above prevailing wholesale market price caps, while customer-class estimates vary widely within individual markets. Although methodologies differ, all report substantial variation by customer class, and many headline values are several multiples of applicable wholesale price caps. This does not mean the studies are incorrect. It means the economic harm of an involuntary outage is not necessarily the price required to elicit a voluntary, partial reduction in demand.

The policy conclusion is not that VoLL should be discarded. It remains essential for evaluating residual outage risk, especially for consumers unable to participate or protect themselves. Rather, market designers should avoid using VoLL as a universal proxy for the marginal price needed to mobilize flexibility. As participation technologies spread, some reliability preferences can be revealed directly through offers and responses.

3. From a One-Sided to a Two-Sided Reliability Market

A one-sided wholesale market treats reliability principally as a service supplied by generators and purchased collectively for consumers. Demand is represented by a forecast rather than by a schedule of price-responsive bids. Even where retail customers face time-varying rates, their actions may not be integrated directly into wholesale dispatch. The result is an asymmetric market: supply reveals marginal costs while demand is largely assumed.

A genuinely two-sided market permits both supply and demand to express the prices and conditions under which they are willing to provide energy or flexibility. A generator offers energy at a price reflecting fuel, variable operating cost, opportunity cost and risk. A flexible load can similarly offer to reduce consumption at a price reflecting production value, comfort, inconvenience, degradation or foregone use. For example, a flexible load with a battery can offer to discharge the battery when the wholesale value exceeds the customer's opportunity cost of stored energy. These actions create an observable schedule of stored energy that would be made available to the wholesale electricity market and improve system reliability.

This approach also recognizes that customers need not choose between full consumption and complete disconnection. Flexibility is often divisible. A data center may defer a noncritical computing task; a manufacturer may adjust one process while maintaining essential operations; a home may pre-cool, delay vehicle charging or export a limited quantity from a battery. Partial flexibility can therefore be available at prices far below the value associated with fully curtailing electricity on the site and having to cease all electricity-powered activities.

Aggregation is crucial to smaller customers, because the transaction costs of individual participation would otherwise be prohibitive. An aggregator can forecast availability, control devices, satisfy telemetry requirements, submit offers, manage performance risk and allocate revenues. FERC's distributed energy resource framework under Order 2222 recognizes that aggregations allow small resources to meet minimum size and performance requirements that they could not satisfy individually.

The potential benefits of broader demand-side participation are subject to two important qualifications. First, revealed participation is not automatically socially optimal. Customers may face distorted retail prices, limited information, liquidity constraints, privacy concerns or contractual barriers. Aggregators may exercise market power or design compensation poorly (and therefore not attract sufficient number of participants). Second, voluntary flexibility cannot substitute for every reliability function that an electric power system may need. Frequency response, voltage support, and black-start capability have distinct technical requirements that may not be well suited for aggregation of small energy providers. A two-sided framework therefore broadens the set of resources that can contribute to reliability, but it does not eliminate market design challenges or the technical requirements of reliable power system operation.

4. ERCOT Case Study and Modeling Framework

Winter Storm Uri provides the trigger for assessing the Texas market landscape and why we choose it as the focus market for this study. Prior to the event, ERCOT's planning outlook indicated substantial supply relative to expected demand. The December 2019 Capacity, Demand and Reserves ("CDR") report projected an approximately 49% reserve margin for the 2020/2021 winter, suggesting that, on a planning basis, the system had ample installed resources to meet forecast peak demand (ERCOT, 2019). The reliability challenge exposed by Winter Storm Uri was therefore not simply one of insufficient installed capacity, but of whether available resources could perform under extreme system conditions. During February 14-19, 2021, ERCOT experienced widespread generation outages, prolonged load shedding and exceptionally high real-time prices (ERCOT, 2021). The event highlighted interdependencies among electric generation, fuel supply, weatherization and emergency operations. In response, Texas introduced numerous reforms, including a revised reliability standard, new ancillary services, changes to scarcity pricing and more "conservative" operational requirements (PUCT, 2025).

Most reforms understandably focused on supply. Yet, customers also adapted. Market experience from recent years in ERCOT offers evidence that demand can respond at prices well below conventional VoLL estimates. Large industrial and commercial loads can participate as demand-response resources or voluntarily reduce consumption when prices rise. During tight conditions, for example, during Winter Storm Heather (January 2024), the system operator observed significant voluntary curtailment by some flexible loads suggesting reservation prices in the hundreds rather than thousands of dollars per megawatt-hour (ERCOT, 2024a). Such behavior reveals the price at which a subset of consumption becomes economically interruptible.

To explore whether this logic can extend beyond large loads, we modeled a hypothetical aggregation of residential rooftop solar paired with two-hour battery energy storage systems. The exercise is intentionally illustrative. It does not forecast enrollment in a specific commercial program, nor does it assume residential batteries are dedicated to wholesale-market service. Instead, it asks whether a limited portfolio of customer-owned assets, dispatched only during high-value conditions, could produce measurable system benefits while preserving most behind-the-meter use.

The assumed aggregation reaches 1.2 GW by 2030, based on ERCOT load-growth projections and observed solar-plus-storage attachment rates (ERCOT, 2025; Berkeley Lab, 2025). This represents approximately 1% of projected ERCOT peak demand of 135 GW for 2030 (ERCOT, 2025). Participating resources are essentially modeled as a virtual power plant. The aggregator dispatches stored energy from its portfolio which is composed of multiple individual households and their stored energy devices. The dispatch of the stored energy is assumed to occur only when the wholesale real-time energy price exceeds $200/MWh, a threshold intended to approximate the bid price of such load under typical demand-response compensation arrangements in the U.S. Notably this bid price is above the short-run marginal cost of the most expensive conventional peaking resources in the modeled supply stack, so it does not undercut any competitive generation offers. Customers receive 50% of the incremental energy-market revenues generated by the aggregation as an illustrative revenue-sharing assumption; actual VPP arrangements vary. For example, under Tesla's ConnectedSolutions program, participating Powerwalls are dispatched during summer peak events, customers are compensated based on their average contribution during those events, and Tesla passes 80% of the program incentive to participating customers (Tesla, 2026).

The analysis uses London Economics International LLC's proprietary electricity market simulation model (POOLMod) to approximate security constrained economic dispatch and ERCOT's real-time market operations. POOLMod constructs resource availability

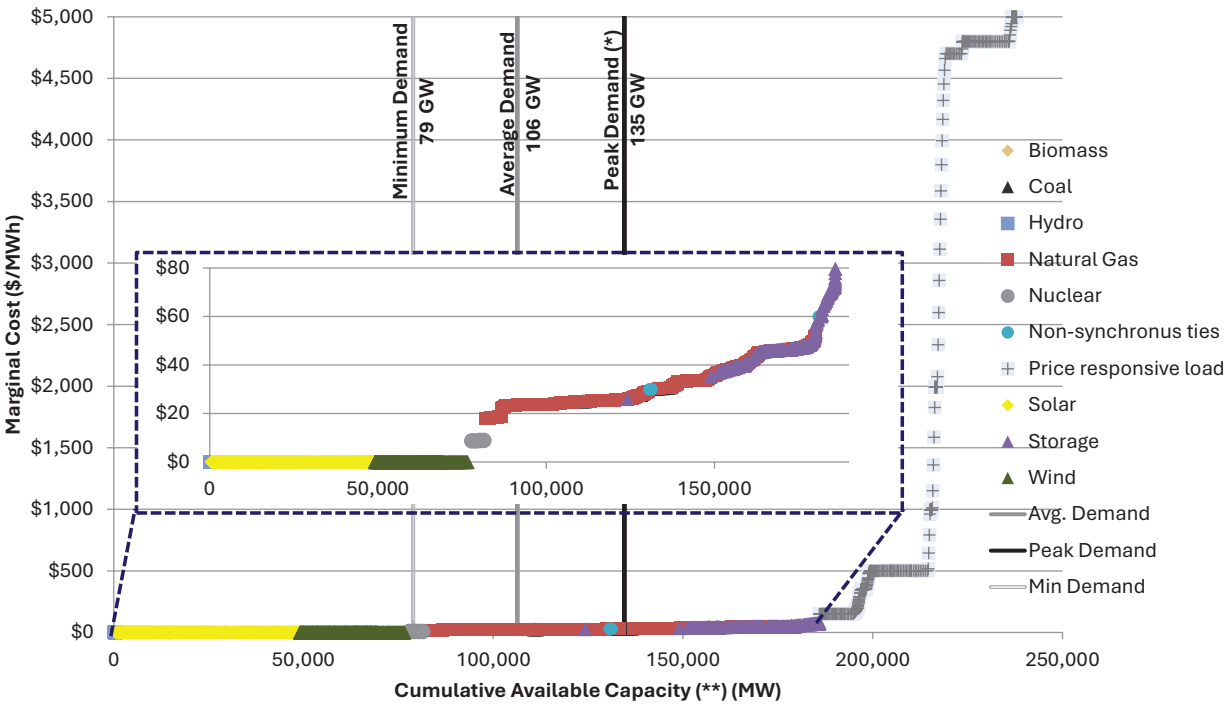

Figure 2: Supply curve using available capacity (2030)
Note: (*) Peak demand prior to any voluntary curtailment. (**) Available capacity reflects thermal resources adjusted for scheduled and unplanned outages, while solar and wind capacity is derated based on the respective annual capacity factors.

schedules, commits generation to meet projected load and dispatches resources hourly subject to operating and transmission constraints.[1] Outputs include zonal energy prices, generation, market costs, production costs, curtailment, demand-side deployment and loss of load.

The simulation of ERCOT's expected market in 2030 includes unit and locational representation of all operating and planned resources which total approximately 247 GW (at maximum seasonal capacity) and consist of 113 GW of renewable generation, 107 GW of thermal resources, 25 GW of storage, 2 GW of DC ties and a small remainder of other technologies. The analysis incorporates 5.8 GW of retirements from 2026 through 2029, including 3.2 GW formally announced to ERCOT. Wind and solar profiles are based on hourly data consistent with a normal weather year profile. The transmission representation includes major internal transmission interfaces between load zones (ERCOT's Houston, North, South and West load zones) and transmission thermal limits calibrated to observed maximum system flows. Fuel price assumptions range from $2/MMBtu to $3/MMBtu for natural gas (depending on gas hub), with an average coal price of $3/MMBtu, informed by futures and EIA's 2025 forecasts from the *Annual Energy Outlook* (EIA, 2025).

On an aggregate basis, baseload natural gas plants (CCGTs) are on margin to meet average demand while peaking natural gas plants (Frame, aeroderivative, and steam turbine units) are on the margin to meet peak demand in ERCOT in 2030, as shown below in Figure 2.

Demand is based on official forecast from ERCOT (as of April 2025) and totals 932 TWh annually and peaks at 135 GW (ERCOT, 2025). This load forecast includes nearly 40 GW of new large flexible loads are assumed to curtail voluntarily at bid price thresholds, given the underlying activity of the large load (e.g., crypto mining, various manufacturing processes, and data centers supporting AI training and inference), ranging from $75/MWh to $4,800/MWh.[2]

The analysis compares two cases. The baseline case incorporates this assumed response from large flexible loads but does not include residential aggregation. The alternative case maintains the same market assumptions and large-load response but adds the hypothetical residential solar-plus-storage aggregation as a virtual power plant. Differences in market outcomes between the two cases therefore isolate the incremental effect of residential participation.

To test how the market outcomes vary relative to forced outage patterns of the power plant fleet, the study evaluates 30 forced-outage patterns under the same weather-normal demand. The results should therefore be interpreted as a distribution across outage realizations, not as a complete probabilistic assessment of weather uncertainty.

5. Simulation modeling results

The residential aggregation lowers both production costs and wholesale energy market costs. Energy market costs are measured as the aggregate payments to all generation units over the course of the year, while

production costs reflect the underlying costs of electricity generation, including fuel, variable operation and maintenance, start-up, and cycling costs. This distinction is important for interpreting the results: reductions in energy market costs represent gains in consumer surplus, whereas reductions in production costs represent improvements in static allocative efficiency. As shown in Figure 3, the magnitude of these savings varies materially with thermal-generator availability, ranging from $151 million to $672 million annually and averaging $371 million across the 30 modeled outage patterns. This average is equivalent to roughly 1% of ERCOT's 2030 energy market costs, broadly proportional to the aggregation's approximately 1% share of projected 2030 peak demand.

Figure 4 Illustrates that the magnitude of annual short-run marginal cost savings varies materially with thermal generator availability, ranging from approximately $6 million to $21 million annually and averaging $13 million across the 30 modeled outage patterns.

The result is driven by timing rather than scale alone. The batteries are not dispatched as baseload resources and are not used continuously to suppress prices. They enter only after modeled prices exceed $200/MWh, when the system has begun relying on its highest-cost conventional resources. A relatively small quantity of energy can therefore displace expensive marginal generation and reduce scarcity rents during a limited number of hours.

On average over the 30 iterations with different outage patterns, the residential resources are dispatched for approximately 137 hours over the course of the year. During those events, they use about 41% of the energy stored in the batteries. Dispatch is concentrated in summer months and morning ramping periods, when load, renewable output and quick start thermal availability presents the optimal conditions for use of these resources in an economically efficient way. The limited duty cycle is important: customers retain most battery availability for their own personal use (backup service and other behind-the-meter objectives).

At the household level, the compensation from this voluntary sale into the wholesale electricity market is modest. A representative Texas customer with a 13.5 kWh battery earns approximately $132 annually under the assumed 50/50 revenue split with the aggregator. However, this is the revenue received under weather normal conditions – the value under more extreme conditions is likely to be significantly higher. The income from normal weather deployment is not sufficient to justify battery investment on a standalone basis. But it is an incremental revenue stream, and with abnormal weather, it can defray significant portion of the investment costs. For example, if the stored energy is deployed at the same frequency but during periods of higher prices ($1,000/MWh), the aggregator would earn approximately $384 in annual revenue.

Existing programs demonstrate that the operational concept is feasible even though program rules differ. Sunrun's California distributed power plant enrolls more than 80,000 households and 110,000 home batteries and provides up to 425 MW of peak dispatchable capacity (Sunrun, 2026). In New England, ConnectedSolutions compensates households that allow batteries or smart thermostats to respond during designated system peaks, with customer payments governed by program and aggregator revenue-sharing arrangements (Mass Save, 2026; Tesla, 2026). These examples show that

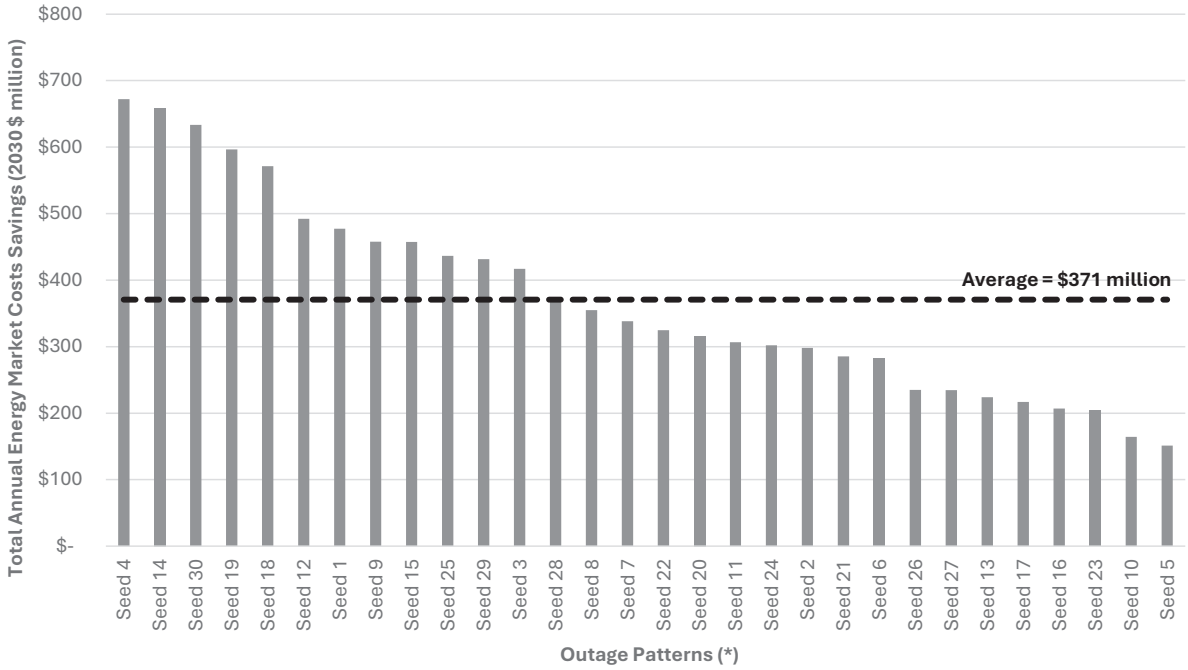

Figure 3: Modeled annual ERCOT energy market savings across 30 thermal-outage patterns
Note: (*) Each seed represents a unique annual outage pattern.

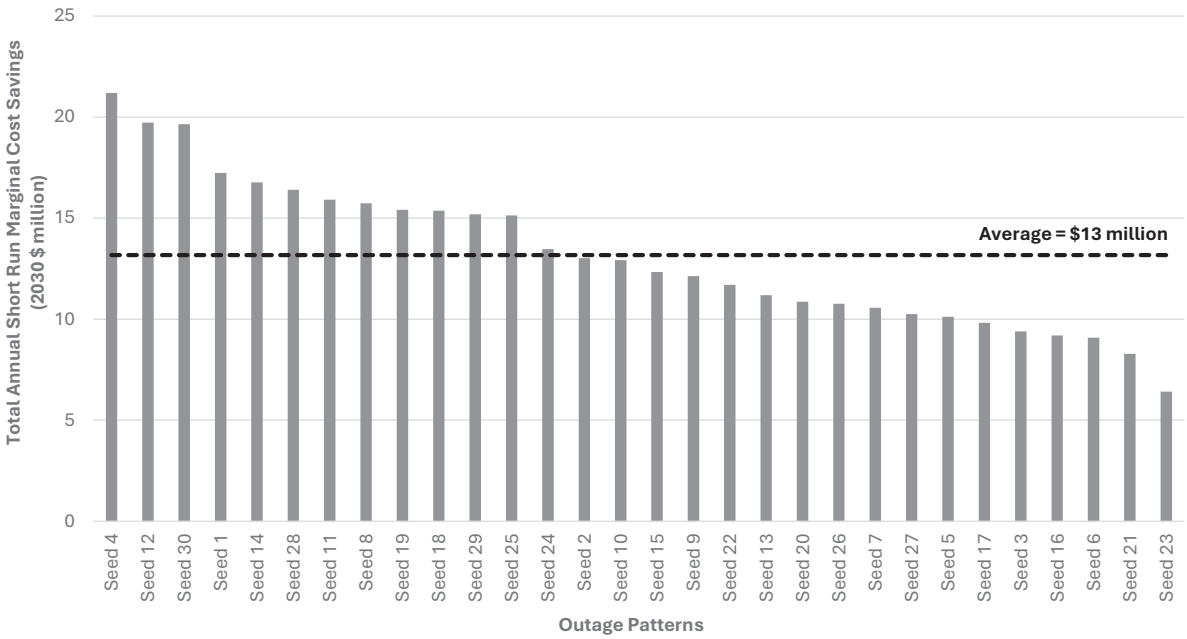

Figure 4: Modeled annual ERCOT short run marginal cost savings across 30 thermal-outage patterns

customer enrollment, remote control, event dispatch and revenue sharing are no longer purely theoretical.

The modeled savings should nevertheless be interpreted cautiously. Lower wholesale electricity prices benefit load (consumers) but may reduce revenues for generators needed for long-run adequacy. In the modeled cases, however, the resulting impact on generator profitability was not material. The analysis does not quantify distribution-network impacts, telemetry costs, battery degradation, rebound consumption, customer-acquisition costs or capacity value. Nor does it evaluate extreme multiday energy shortages in which two-hour batteries may provide limited support. The results establish economic potential under a defined operating rule, not a complete benefit-cost test.

6. Policy Implications and Research Priorities

The first implication is conceptual: reliability valuation should distinguish involuntary outage damage from voluntary participation value. VoLL remains appropriate when the decision concerns the residual risk that electricity will be unavailable despite customers' preferences. It is less appropriate as the assumed price required to obtain every form of demand flexibility. Market offers, dynamic tariffs and aggregator contracts can reveal a lower and more granular schedule of voluntary response.

Second, market rules should be technology-neutral but performance-specific. Flexible demand, storage and generation should compete where they provide comparable services, subject to requirements for response time, duration, availability, telemetry and verification. Technology neutrality does not mean ignoring physical differences. It means defining the product around the reliability need rather than around the identity of the incumbent provider.

Third, scarcity prices must remain credible. Demand-side participation has greater value in markets where prices reflect system conditions. Persistent price suppression, broad out-of-market intervention or frequent administrative commitment can reduce the opportunities through which power plants recover their costs and distort the investment signal for new infrastructure. At the same time, unmitigated price spikes are not a substitute for effective market design. A stable framework requires credible scarcity pricing, rules that encourage and support demand participation and settlement arrangements that reward measured performance.

Fourth, demand-side participation (and the flexibility it affords the power system) should be viewed as a transition resource rather than merely an emergency program. New generation and transmission can require years to permit and construct. Customer-owned devices already installed for other purposes can sometimes be aggregated more rapidly, then returned to normal behind-the-meter use when system conditions ease. This reduces stranded-asset risk and provides optionality while longer-lived infrastructure is developed.

Several research priorities follow. Empirical work should estimate participation supply curves by customer class, technology, event duration and season. Randomized program designs can test how compensation, automation and opt-out provisions affect enrollment and performance. Production-cost studies should incorporate multiple weather years, correlated fuel and generator outages, distribution constraints and long-duration scarcity. Capacity-expansion models should examine whether demand-side participation changes the efficient generation mix or merely shifts revenues. Finally, reliability assessments should evaluate distributional effects: customers unable to purchase flexible

technologies should benefit from system savings rather than subsidize participants disproportionately.

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Footnotes

[1]For a more detailed description of LEI's proprietary electricity market simulation model, POOLMod, see LEI (2025), Analysis of Alternative Market Designs to the Single Market Clearing Price for the ERCOT Region, Appendix B. <https://interchange.puc.texas.gov/search/documents/?controlNumber=58847&itemNumber=8>

[2]While the quantity of load curtailed is based on ERCOT's load forecast (ERCOT, 2025), the associated bid-price thresholds reflect LEI's estimates of these customers' opportunity costs of electricity consumption.

Carbon Pricing for Green Hydrogen Adoption: Insights from a Firm-Production Model

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Abstract

Despite Europe-wide mandates to boost hydrogen deployment, its adoption remains low. This article relies on a firm-production model to examine the effect of carbon pricing on green hydrogen cost-competitiveness relative to other energy sources. The results show that the required carbon price thresholds are well above current and expected levels. We find a lower bound of 150€/tCO_2 and, depending on the scenario and assumptions, upper bounds exceeding 5000€/tCO_2 suggesting that aggressive complementary policies are needed to support the widespread adoption of green hydrogen.

Introduction

The European Union (EU) has set a legally binding objective to achieve climate neutrality by 2050 and to reduce greenhouse gas (GHG) emissions by at least 55% by 2030 compared to 1990 levels (European Commission, 2023). Achieving these targets requires profound transformations across the energy system, including expanding renewable energy deployment, improving energy efficiency, and reducing reliance on fossil fuels such as natural gas in favour of low-carbon alternatives (Council of the European Union, 2025).

In this context, hydrogen, particularly green hydrogen, is increasingly recognised as a key component for decarbonising hard-to-abate sectors such as industry and transport. As of 2022, hydrogen accounted for less than 2% of Europe's energy consumption and was primarily used in chemical production, such as plastics and fertilisers (European Commission, 2024). However, around 96% of this hydrogen was produced from fossil fuel, in particular natural gas. To support its broader objective of achieving climate neutrality by 2050, the EU aims for green hydrogen to supply around 10% of its energy demand by 2050, thereby supporting the decarbonisation of energy-intensive industrial processes and transport (European Commission, 2024).

Despite these ambitions, the large-scale deployment of green hydrogen remains challenging. According to the International Renewable Energy Agency (IRENA), several barriers persist, including limited infrastructure, underdeveloped markets, and, most importantly, high costs relative to alternative energy sources. For instance, IRENA indicates that green hydrogen is currently two to three times more expensive to produce than fossil-based alternatives such as oil and natural gas (IRENA, 2024).

Addressing this cost gap is therefore central to enabling large-scale adoption. A range of policy instruments can contribute to improving the cost-competitiveness of green hydrogen, including targeted subsidies, investment support for infrastructure, innovation policies, and demand-side mechanisms such as quotas or contracts for difference. Additionally, carbon pricing may play a particularly important role in green hydrogen cost-competitiveness, by increasing the cost of carbon-intensive fuels, thereby narrowing the cost differential with low-carbon alternatives.

Such a mechanism is already implemented in the EU through the EU Emissions Trading System (EU ETS), which assigns a price to CO_2 emissions, creating incentives for firms to reduce emissions by investing in low-carbon technologies (European Commission, 2025b). Carbon pricing increases the cost of carbon-intensive production both directly, through emissions pricing, and indirectly, by raising the cost of energy inputs such as fuels (Venmans et al., 2020). Given this shift in relative prices, a key question arises: is there a carbon price threshold at which green hydrogen becomes cost-competitive enough to substitute other energy sources?

We develop a firm-production model to estimate the carbon price thresholds at which green hydrogen becomes cost-competitive with other energy sources. This model is calibrated to represent a stylised firm across all industries in Luxembourg, using data on average to industrial energy consumption and input prices over the period 2022-2024. Luxembourg provides a particularly relevant case study. First, despite its small size, it exhibits very high energy use, with per-capita energy consumption remaining about twice the EU average, indicating a structurally energy-intensive system (Enerdata, 2026). Second, the country is highly dependent on external energy sources: its energy import dependency reaches around 91%, one of the highest levels in the EU (Eurostat, 2026). This strong reliance on imports implies that any domestic low-carbon energy solution, such as green hydrogen, must compete with energy carriers shaped by cross-border markets and European carbon pricing.

Empirical Approach

A. Firm-Production Model

The analysis relies on a firm-production model that determines the optimal quantity of each input used by the industry. In this framework, a representative firm combines capital, energy, and labour to produce output (Figure 1). The energy input is further disaggregated into four sources: electricity from renewable energy sources (renewables), green hydrogen, oil, and natural gas. Carbon pricing enters the model by increasing the effective cost of fossil fuels (natural gas and oil) in proportion to their CO_2 emissions, thereby altering relative energy prices and influencing input choices.

Building on the fuel-switching literature, indifference thresholds are defined as the carbon price at which

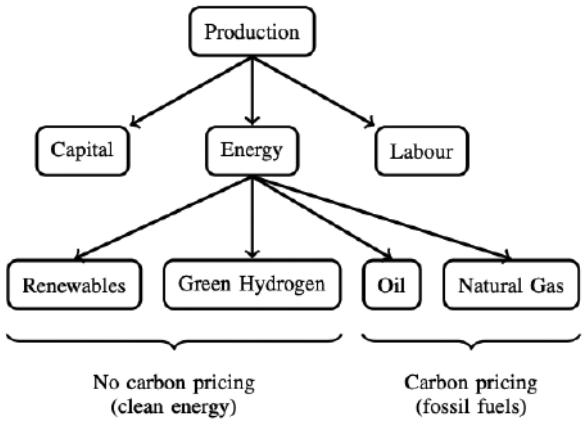

Figure 1: Production Model Schema. The figure summarises the firm input decision-making, with special focus on energy sources. All energy inputs are sourced from their respective markets.

firms are indifferent between alternative energy inputs. In this context, the switching point refers to the carbon price that equalises the effective marginal costs of competing energy sources, including CO_2 emissions (refer to Bertrand (2014) for an overview).

The analysis begins with a Cobb-Douglas production function specification, which provides a tractable benchmark and transparent analytical insights, but imposes a unitary elasticity of substitution across inputs. This assumes that different energy sources can be substituted on a one-to-one basis. To relax this assumption, the analysis is extended to more flexible functional forms: a constant elasticity of substitution (CES) aggregation within a Cobb-Douglas energy composite, allowing for more realistic differences between energy sources that better reflect real-world substitution possibilities, particularly between clean and fossil inputs, while maintaining analytical clarity.

While the model is based on Luxembourg annual data from 2022 to 2024, the results are expressed as a firm's input decision at a given point in time, thereby reflecting a static snapshot rather than a dynamic decision-making process. This decision is characterised by a fixed level of output.

B. Data

The calibration of the model relies on data to represent a stylised firm across all industries in Luxembourg. We use annual data on energy prices for renewables[1] and natural gas[2] from Eurostat, and oil[3] from the U.S. Energy Information Administration. As market prices for green hydrogen are not yet well established, we proxy its price using estimated production costs in Luxembourg based on data from the European Hydrogen Observatory.[4]

For calibration purposes, industry-level energy consumption data for Luxembourg covering the period 2022–2024 are obtained from Eurostat. Electricity from renewable energy sources (i.e., renewables) is approximated using the share of renewables in total country-wide electricity generation from Statec.[5] In addition, data on natural gas and oil consumption are sourced from Eurostat.[6]

Results

Table 1 reports the outcomes of the model calibration by comparing the model's implied input mix with the average observed energy inputs over the study period, evaluated at prevailing carbon prices in Luxembourg. Based on a Cobb-Douglas production function, the model underestimates natural gas and oil consumption and overestimates the use of renewables and green hydrogen. This mismatch likely reflects the model's restrictive assumption about how easily firms can switch between different energy sources, which limits its ability to capture more realistic substitution patterns. As a result, the model exhibits an upward bias toward cleaner technologies, implying that subsequent estimates (such as the carbon price required for green hydrogen competitiveness) are likely conservative and may in reality be higher.

It should be noted that this comparison is based on the 2022–2024 period, during which carbon prices in Luxembourg ranged between 25€ and 35€ per tonne of CO_2 (€/tCO_2). As such, the results reflect model performance under these observed conditions and may not generalise to other carbon price levels. Nevertheless, our results provide a tractable benchmark for our analysis.

Based on this specification with the Cobb-Douglas production function, Figure 2 illustrates the resulting energy sources demand responses to changes in the carbon price at a specific point in time (i.e., a static snapshot). Under this specification, two main results emerge. First, fossil fuel use declines smoothly as carbon prices increase, while green hydrogen becomes progressively more cost-competitive. Second, the implied carbon price thresholds, denoted by (1) and (2), differ markedly across fuel sources. Green hydrogen becomes cost-competitive with oil at approximately 261€/tCO_2 whereas the threshold relative to natural gas is substantially higher, at around 5968€/tCO_2.

We next consider a CES aggregation within a Cobb-Douglas energy composite production function. A central result is that the carbon price thresholds are highly sensitive to the elasticity of substitution, as shown in Table 2.

Two key patterns emerge. First, higher elasticities of substitution are associated with systematically lower carbon price thresholds. This means that the more easily firms can switch between different energy inputs (in this case between fossil and clean energy sources), the lower the carbon price required for green hydrogen to become cost-competitive. Second, this effect is particularly pronounced for competition between green hydrogen and natural gas. For example, when the elasticity increases from 0.5 to 5 (a range chosen because no threshold emerges below 0.8 within the considered carbon price range, while higher values illustrate increasing substitutability), the threshold for oil declines from 310€ to 150€/tCO_2, while the threshold for natural gas decreases dramatically from effectively unattainable levels to below 300€/tCO_2. In contrast, no threshold is observed between renewables

Table 1: Model Calibration. Average observed and predicted energy inputs over the 2022-2024 period.

Variable	Observed (GWh)	Model (GWh)	% difference
Natural Gas	2296	2061	-10.24%
Oil	210	145.76	-30.59%
Renewables	567.33	857.05	+51.07%
Green Hydrogen	15	24.55	+63.67%

Note: We compute the model based on the observed carbon prices in Luxembourg (30€/tCO_2) and report average values over this period. The yearly calibration exercise follows the same pattern, based on a carbon tax of 25€/tCO_2in 2022, 30€/tCO_2 in 2023, and 35€/tCO_2 in 2024.

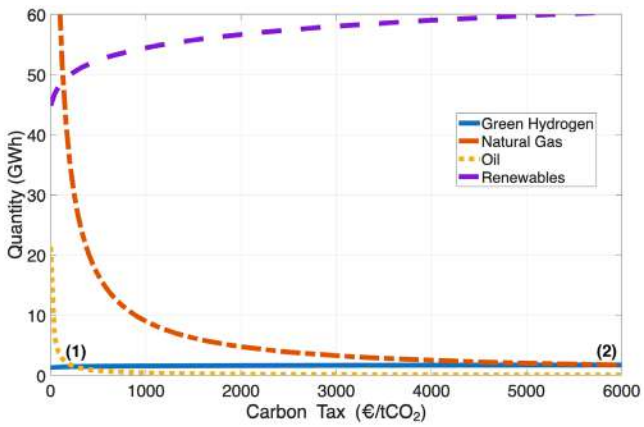

Figure 2:: Energy Input Use as a Function of Carbon Pricing. The figure illustrates the thresholds where green hydrogen becomes cost-competitive compared to oil and natural gas, denoted by (1) and (2), respectively. Note that no threshold arise between green hydrogen and renewables up to carbon prices of 6000€/tCO_2. higher, at around 5968€/tCO_2.

Table 2: Carbon price thresholds

	Thresholds		
Elasticity of substitution	Oil vs. H_2	Natural gas vs. H_2	Renewables vs. H_2
0.5	-	-	-
0.8	310.5	-	-
1.5	210.3	1752.9	-
2.5	170.2	641.1	-
3	160.3	500.8	-
3.5	160.3	410.7	-
4	150.3	360.6	-
4.5	150.3	320.5	-
5	150.3	290.5	-

Notes: Thresholds are presented in €/tCO_2. The analysis considers a range of carbon pricing from 0 to 6000. Dashes indicate that no threshold exists for the specific input substitution.

and green hydrogen within the considered carbon price range: even at prices up to 6000€/tCO_2, green hydrogen does not become cost-competitive with electricity from renewable energy sources.

These results highlight the importance of accurately estimating the elasticity of substitution among inputs as the carbon pricing thresholds are highly sensitive to this parameter. As emphasised by Kopečná et al. (2026), substitution elasticities are key drivers of model outcomes, determining how economic agents respond to price signals such as carbon pricing. When substitution is limited, extremely high carbon prices are required to induce a transition toward green hydrogen. Conversely, when substitution is easier, moderate carbon prices are sufficient to achieve cost-competitiveness against fossil fuels.

Discussion

The carbon price required for green hydrogen to become cost-competitive relative to alternative energy sources is generally high, ranging from approximately 150€ to more than 4000€/tCO_2, depending on the respective production process. These thresholds vary substantially across production specifications and are well above the current carbon pricing observed in practice. For example, carbon prices under the EU ETS averaged approximately 69€/tCO_2 between November 2023 and October 2025 (European Commission, 2025a). Furthermore, Sweden's carbon price of around 138€/tCO_2, one of the highest worldwide, remains below the lower bound of our estimates.

Looking ahead, scenarios consistent with the EU's climate objectives suggest that effective carbon prices could rise to around 150 €/tCO_2 by 2030 (Tovar Jalles et al., 2024). Even under these expected increases, carbon prices remain well below the levels required for green hydrogen to become broadly cost-competitive. It is important to interpret these thresholds in light of the model calibration. The model tends to overestimate the demand (in GWh) of renewables and green hydrogen while underestimating fossil fuel demand, implying an upward bias toward cleaner technologies. As a result, the estimated thresholds are likely conservative, and the true carbon price required for green hydrogen competitiveness may be even higher. This suggests that current and anticipated carbon price signals are insufficient to induce large-scale substitution from fossil fuels toward green hydrogen in industrial production.

Overall, green hydrogen is therefore more likely to play a complementary role than to become a direct substitute for fossil fuels under current technological and economic conditions. Therefore, instead of substituting existing energy sources, green hydrogen is more likely to play a complementary role in supporting, for example, systems with high renewable energy penetration or in industrial applications where low-carbon alternatives are limited. Carbon pricing alone appears insufficient to drive widespread hydrogen adoption, implying that a broader policy mix will likely be required, including measures aimed at reducing

hydrogen production costs, expanding transport and storage infrastructure, and supporting deployment through targeted financial and industrial policy instruments.

We next examine how the thresholds are affected by the chosen elasticity of substitution between energy inputs. The results indicate that higher substitution elasticities reduce the carbon price required for green hydrogen to become cost-competitive. Intuitively, higher substitution elasticities make input demand more responsive to relative price changes: carbon pricing raises the marginal cost of carbon-intensive inputs, inducing a stronger and quicker shift toward cleaner alternatives. When substitution is limited, larger cost increases are needed to trigger such adjustments, resulting in higher carbon price thresholds.

Nevertheless, even under relatively high elasticities, the thresholds remain well above observed and future carbon prices. Therefore, while greater production flexibility enhances the effectiveness of carbon pricing, it does not fundamentally alter the conclusion that carbon pricing alone is insufficient to make green hydrogen broadly cost-competitive.

At the same time, even if green hydrogen is not cost-competitive on a purely price basis, along other storage technologies, it may still play a role in fully decarbonised energy systems. In particular, the intermittency of renewable energy implies that additional flexible and storable energy carriers may be required to cover periods of low generation. This suggests that hydrogen demand may emerge not only from cost considerations, but also from system-level constraints (e.g., the market will store excess electricity in green hydrogen that can then be used in, for example in industrial processes).

Conclusion and Future Research

This article examines the carbon price thresholds at which green hydrogen becomes cost-competitive with alternative energy sources in industrial production. The central finding is that the required carbon prices are high, ranging from around 150€/tCO_2 to more than 5000 €/tCO_2. These levels are well above both current and expected future carbon prices, implying that carbon pricing alone is unlikely to make green hydrogen broadly cost-competitive under current technological and cost conditions.

While instructive, the analysis has several limitations that need to be addressed to increase the robustness and generalizability of the findings. First, the analysis relies on stylized production functions and calibrated parameters for a representative firm across all industries in Luxembourg, which does not account for sector-specific heterogeneity. While accounting for sector-specific characteristics, these simplifications allow us to isolate the role of relative prices and substitution patterns in a transparent way. As such, the results should be interpreted as indicative of the magnitude of carbon price changes required, rather than as precise sectoral predictions.

Second, our current analysis focuses on the firm decision-making on a single point in time. Temporal dynamics like generation intermittency or input cost variations may play a significant role on the green hydrogen cost-competitiveness.

In our future work, we will extend the model to address some of these limitations. In particular, we consider a set of extreme scenarios (e.g., very high input costs or the absence of renewable generation) to capture aspects of temporal variability and identify the conditions under which green hydrogen may become cost-competitive. We will further explore the possibility to extend the model to a dynamic hourly optimisation problem, thereby providing a more comprehensive assessment of the role of green hydrogen in future decarbonised energy systems. Nevertheless, our current results provide a useful first step toward uncovering the true role that carbon pricing may (or may not) play in shaping the industrial attractiveness of green hydrogen.

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During the preparation of this work the authors used Grammarly, ChatGPT and Microsoft Copilot for proofreading and style improvement. After using these tools/services, the authors reviewed and edited the content as needed and take full responsibility for the content of the publication.

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Footnotes

[1] Price of renewables

[2] Price of natural gas

[3] Price of oil

[4] Cost of hydrogen production

[5] Renewables Energy Share for Electricity

[6] Consumption of natural gas and oil