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Article

A Methodology for Firm Capacity Planning, Including the Economic Feasibility Assessment of a Hydrogen Storage–Based Generation Project

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Abstract: A high penetration of wind and solar generation within the generation mix will result in an increased supply risk due to the random variations inherent in renewable generation. This document proposes a new methodology for calculating system marginal costs as part of generation fleet expansion planning that accounts for the impact of these random variations. This new methodology incorporates an additional cost into the marginal cost calculation, reflecting the risk of supply deficits during periods of scarcity. This allows for the inclusion in the planning process of generation units that contribute to the electricity system firm capacity, thereby enhancing the security of supply to meet demand. As an example, this document analyzes the economic feasibility of a generation project that utilizes hydrogen (H_2) as fuel. The project combines H_2 production for industrial use, powered by renewable generation (the GH_2 project), with the provision of firm capacity supplied by a gas turbine (TG) generator fueled by H_2 (the hybrid project). The economic feasibility of this hybrid project stems from two key factors: i) intra-annual energy arbitrage—purchasing energy from the electricity market during periods of the year characterized by low marginal costs, and selling energy during periods of scarcity with high marginal costs; and ii) maximizing the electrolyzer's capacity factor by purchasing energy in the market during hours when the electrolyzer possesses residual capacity (i.e., capacity not currently utilized by the GH_2 project). The project incorporates H_2 storage within salt domes.

Keywords: Electricity Markets; Market Prices; Optimal Planning; Reliability Analysis; Green Hydrogen; Renewable Energy; Energy Transition; GH_2 to Power Projects

1. Introduction

The energy transition is accelerating worldwide, driven by proactive energy policies and a significant reduction in capital expenditure (CAPEX) for renewable energy generation (wind and solar). The new paradigms demand more reliable and efficient electrical systems, characterized by high levels of power quality and reliability [1–3].

Operational challenges associated with the intermittent production characteristic of renewable generation are expected to increase with the greater share of renewable generation anticipated in the medium term in most electrical systems worldwide. Addressing these challenges includes ensuring firm capacity to meet demand during periods of high demand and low renewable generation.

As an example, in the Texas (TX), USA electricity market (Electric Reliability Council of Texas or ERCOT) in 2025, the following peak values of demand and renewable generation (wind, solar) were recorded [4] (**Table 1**).

As a result of the intermittency of renewable energy generation, the thermal generation requirement to meet demand is shown in the following figure (duration curve) (**Figure 1**). It can be seen that the maximum thermal

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generation requirement reaches 70,000 MW. This implies that even though renewable generation has a maximum capacity of 59,000 MW, it only contributed 13,000 MW (15%) to reliably meet demand.

Table 1. ERCOT Demand—Renewable generation maximum values 2025.

Metric	Unit	Value
Dem. MAX	MW	83,376
WIND MAX	MW	28,265
SOLAR MAX	MW	29,803

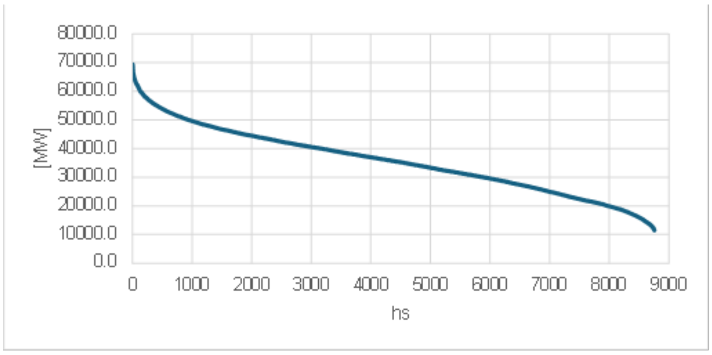

Figure 1. ERCOT (TX). Thermal generation requirement.

Achieving operational security is primarily addressed by incorporating energy storage systems (BESS). The low storage capacity of BESS (typically 3–4 h) means that their contribution to security of supply (firm capacity) is limited, since it cannot be guaranteed that in the event of an unexpected critical event, the batteries will have enough stored energy to meet demand. A strong expansion of intermittent renewable generation may introduce operational risks that cannot be limited by batteries, requiring other technological solutions that allow for greater storage capacity and operating modes that guarantee the availability of firm capacity in the electrical system.

The energy transition will require a competitive hydrogen (H_2) market, which has become increasingly important in various sectors, such as industry and transportation. H_2 is produced through electrolysis, where water is converted into H_2 and O_2 using electricity from a renewable source. Typically, the electrolizer has a load factor of around 30%–40%.

The remanent capacity of the electrolyzer can also be used to produce H_2 by buying energy in the electricity market and storing H_2 in underground salt caverns (saline domes) (**Figure 2**). The stored H_2 is used to generate electricity by a thermal power plant (or fuel cells). The thermal generator (TG) produces energy during the hours of the year when thermal generation is maximum (so when market prices are higher).

In electrical systems with a high penetration of renewable generation, curtailment events—specifically regarding solar and wind generation—are common due to transmission grid constraints that limit the power these generators can deliver to the transmission system. The evaluated project can utilize this excess renewable energy to produce H_2, thereby reducing the renewable energy curtailment.

This allows for a firm capacity to supply demand for periods of up to 800 h/year, mitigating the intermittent problems inherent in renewable generation by supplying firm capacity during periods of low reserves [5,6].

The high-voltage switchgear configuration (breaker-and-a-half) allows the electrolyzer to receive energy from both the solar generator and the electrical system at the same time. This allows for maximizing the electrolyzer load factor. It also allows the thermal generator to feed power into the grid and enhances reliability.

Research Question

The addition of wind and solar generation systems to electrical systems—significantly increasing their share of the generation mix—introduces an additional stochastic variable into the process of optimally planning the expansion of the generation fleet: the intermittency of energy production. This variable was not present (or was not significant) in traditional planning procedures.

In electricity markets, the energy marginal costs (market prices) serve as the economic signal that determines the new generation capacity required to fulfill the objective of meeting demand at minimum cost and in a secure manner.

Consequently, the anticipated changes in the generation mix should be reflected in the procedure used to determine energy marginal costs by incorporating the impact of aleatory variations in renewable energy production on the risk of supply deficits.

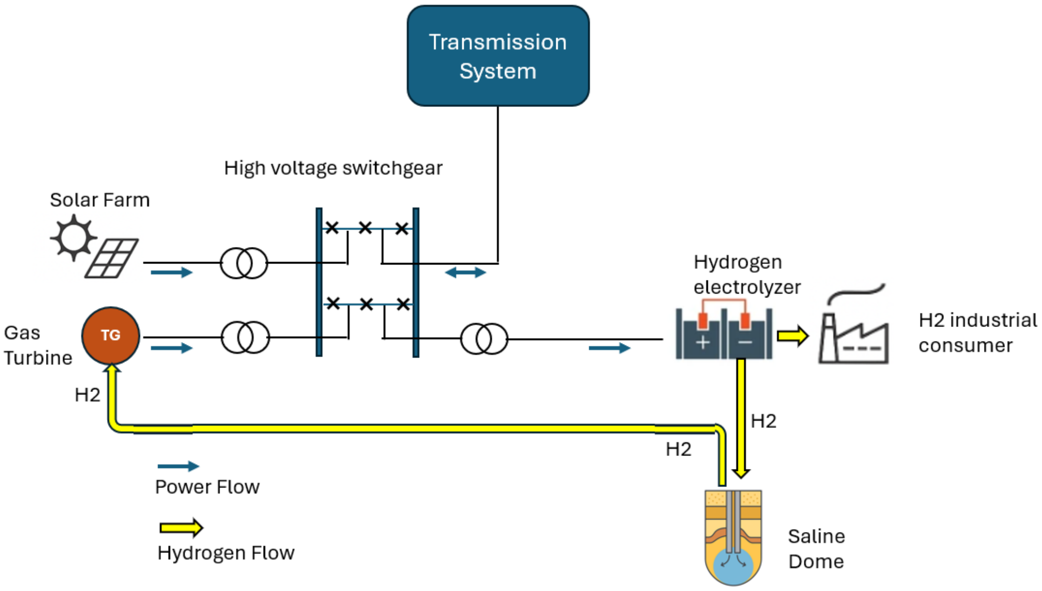

Figure 2. Schematic configuration of a hybrid project, the GH_2 project for industrial uses including a generation project (TG) for providing firm capacity.

Research Objectives

The objective of this document is to define a new methodology that accounts for the impact of stochastic variations in generation costs introduced by the risk of supply deficits associated with a significant variable renewable energy production.

The new methodology for calculating marginal costs is expected to significantly increase their values during periods of scarcity (low reserves). This will enable the optimal generation expansion plan to incorporate new generation projects characterized by low load factors, that is, projects operating as peaking units that produce energy primarily during periods of scarcity when marginal costs are higher.

Typically, generation units operating as peaking units are gas turbine (TG) thermal power plants, since this type of generator has minimal capital costs (CAPEX) and allows for flexible operation, thereby contributing Firm Capacity to the electrical system to ensure the secure supply of demand.

As part of the energy transition, an increase in H_2 production for industrial use through renewable generation (GH_2 projects) is expected. This document analyzes the economic feasibility of hybrid projects (GH_2 + Peaking Unit) as part of an optimal generation expansion plan that allows for supplying demand safely and at minimum cost. The project's capital cost is minimized through a generation project (peaking unit) that maximizes the use of the electrolyzer. The project revenues (peaking unit) result from energy intra-annual arbitrage, buying energy in hours of low energy prices, and selling energy in hours of high prices.

2. Optimal Expansion Generation Planning

Generation fleet expansion planning is a procedure used to determine the future expansion required to meet projected demand safely and at minimum cost. The system marginal costs (energy prices) are the result of this planning process.

In electricity markets, the energy prices are intended to be an economic signal that encourages the installation of new generation capacity, allowing demand to be met safely and at minimal cost [7].

Cost Recovery Theorem

Theorem 1. *If the system generation capacity mix is optimal and all generators are dispatched optimally (in merit order), then the following remuneration scheme will ensure full cost recovery for every generator:*

1. *Whenever load is curtailed, the system marginal cost is set to VOLL (value of lost load),*
2. *Each MWh produced is paid the system marginal cost, i.e., the highest marginal cost of any generator operating at that time or VOLL if load is being curtailed.*

See **Appendix A** for a detailed explanation [8].

Corollary 1. *If conditions 1 and 2 are met, and the electricity market is in economic equilibrium, the new generators resulting from optimal planning recover all their costs (CAPEX + OPEX).*

The economic dispatch of generation determines which generating units supply the demand at any given time. As a result, demand is met by the generating units with the lowest variable production cost (VPC). Meeting the demand involves incurring generation costs associated with fuel consumption by thermal generators and with the generators' O&M costs. In each hour (or market interval), the total cost incurred to generate energy is a function that increases with the demand met.

Optimizing the supply of demand (minimum cost) determines the price of energy in each hour (**Figure 3**), which is equal to the Lagrange multiplier (marginal cost) associated with the constraint total generation = demand.

$$\sum_{G=1}^{N} Eg(G) = Dem \ [\mathrm{MW}]$$

$$CMg\left[\frac{\$}{\mathrm{MWh}}\right] = \frac{d\,Total\ Cost}{d\,Dem}$$

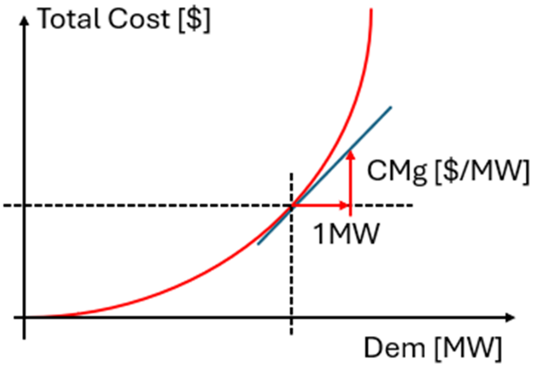

Figure 3. Economic generation dispatch, system marginal cost (*CMg*).

The system marginal cost (*CMg*) resulting from the optimization process increases with the demand met. Under conditions where generation supply is insufficient to meet demand, the *CMg* equals the cost of non-supplied energy (VOLL). The VOLL is a very high value (in some markets it can reach USD 5,000/MWh), and this is the economic signal that incentivizes generator availability.

The energy marginal revenue (MR) earned by generating units each hour results from the difference between the *CMg* and their VPC.

$$\mathrm{MR}[\$] = Eg \times (CMg - \mathrm{VPC})$$

This means that the generating units with higher VPC, typically peaking units, only earn revenue from energy sales when the system's reserve margin is low and there is a possibility that demand cannot be met. These events have a low probability of occurrence, making the energy sales revenue of peaking units highly volatile.

3. Optimal Generation Expansion Planning Considering Uncertainty in the Availability of the Renewable Generation Fleet

Traditionally, the procedure for determining the optimal generation expansion plan considered the production of hydroelectric plants and unscheduled failures of thermal generators as the main random variables. The storage capacity of hydro generators with water reservoirs and the availability of a large number of thermal units as part of the generation fleet allowed the planning process to consider the average available capacity of each generator as a firm capacity attribute that allows to reliably meet demand [9,10].

With an expected growing share of intermittent renewable generation in the future generation mix as part of the energy transition, the uncertainty in renewable generation production should be incorporated into the planning process. The random variable that characterizes renewable generation production requires new calculation procedures to achieve the goal of supplying demand safely and at minimum cost [11–14].

In this new scenario, system marginal costs remain the main variable that determines the optimal generation expansion. For this criterion to be met, the system's marginal costs resulting from the planning process must incorporate the economic signal associated with the risk of not being able to meet demand due to insufficient generation resulting from the randomness of renewable energy production.

Each hour, demand is met by a set of generating units. An unscheduled outage (a failure) of a generating unit creates a shortfall risk, which necessitates reducing demand (load shedding) to maintain the electrical system in equilibrium (generation = demand).

For a given generation fleet, the load shedding risk (unserved energy due to insufficient generation) increases with demand (lower reserve margin). Typically, the probability of unserved energy increases exponentially with an increase in demand.

As an example, the figure below (**Figure 4**) shows the available capacity (blue curve) of a generation fleet composed of 10 (N = 10) conventional thermal generating units with a total installed capacity of 1,400 MW and an average available capacity of 1,260 MW. Each generating unit is considered to have two possible operating states (Available, Unavailable) characterized by an Unavailability Rate. The number of possible operating states is 1,024 (2N). Due to the combined unavailability of generating units, there are operating states where the available capacity of the generation park is less than the demand (red curve), which determines the existence of a Net Operating Status (NSE). The probable average NSE is determined by the area highlighted by red lines.

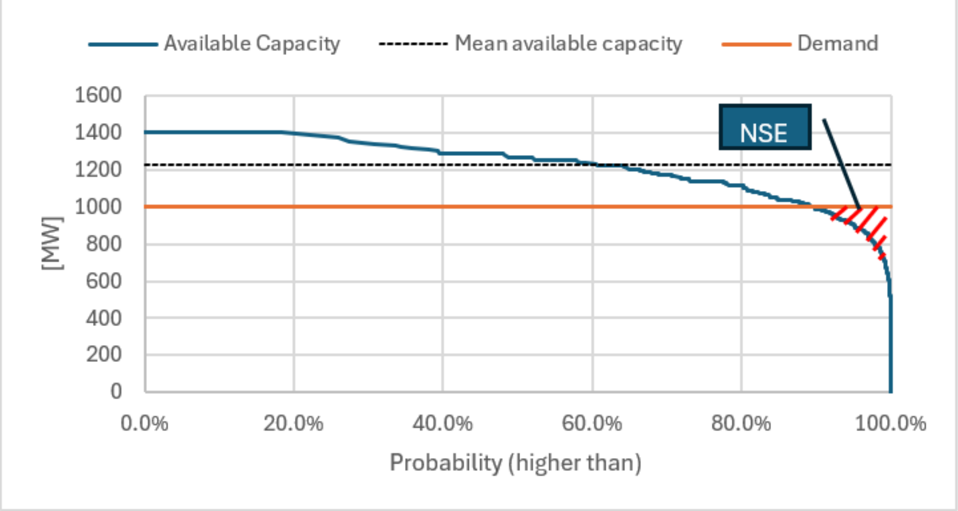

Figure 4. Supply Risk. Probable Non-Supply Energy (NSE) resulting from generators unavailability.

An increase in demand determines an increase in the NSE. The figure below (**Figure 5**) shows the resulting NSE for different demand values ranging from 400 to 1,200 MW.

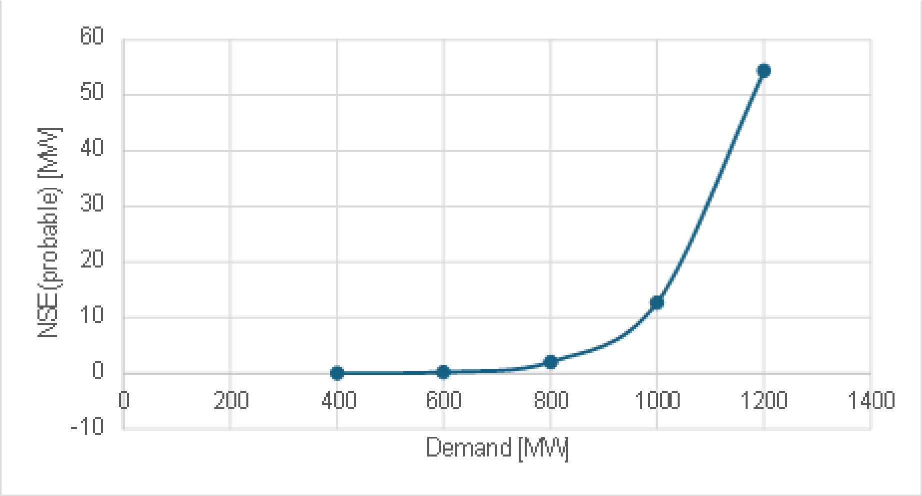

Figure 5. Probable Non-Supply Energy (NSE) when the demand increased.

In electrical markets, the existence of NSE determines a cost for consumers, calculated by valuing the NSE at its unit cost (VOLL [$/MWh]).

Including in the energy price an economic signal associated with the deficit risk incentivizes the availability of generating units, thus promoting the adequacy of the generation fleet. This economic signal, called Deficit Marginal Cost (DMCg) [$/MW], is determined by the derivative of the probable NSE for each demand level (**Figure 6**).

$$\text{DMCg}\left[\frac{\$}{\text{MWh}}\right] = \text{VOLL} \times \frac{d\ \text{NSE}}{d\ Dem}$$

$$\text{DMCg}\left[\frac{\$}{\text{MWh}}\right] = \text{VOLL} \times \text{LOLP}$$

LOLP: Loss of load probability.

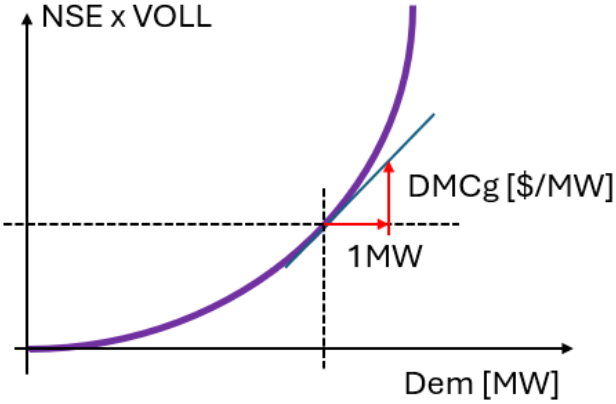

Figure 6. Deficit Marginal Cost (DMCg) resulting from considering NSE risk.

Including the deficit risk, the energy market price (MP) is determined by the sum of the two cost components: i) associated with the production cost, and ii) associated with the deficit risk.

$$\text{MP} = CMg + \text{VOLL} \times \text{LOLP}$$

The following figure (**Figure 7**) presents typical results. It shows that, including the deficit risk in the market price, the market prices are higher during the 2,000 h/year when the reserve margin is minimal. For the remaining hours of the year, the deficit risk is minimal, so the VOLL × LOLP component is zero.

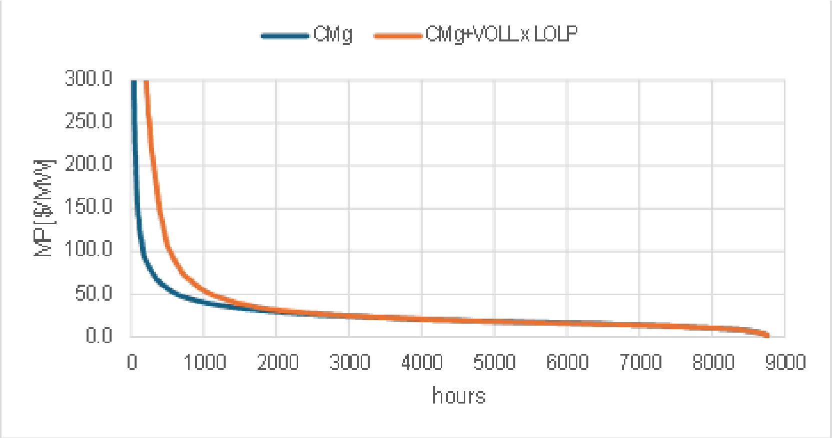

Figure 7. Market prices duration curves, WITH and WITHOUT non-supply energy risk cost.

Incorporating into the planning process the economic signal associated with the risk of deficit added to the marginal cost of generation allows determining an optimal generation expansion plan that takes into account the contribution that each type of project makes to the security of supply of demand while minimizing the cost of supplying demand.

4. Market's Prices Determination—Convolution Algorithm

In the electricity market, the price of energy results from the balance between supply and demand in each market interval (Lagrange multiplier associated with the demand = generation constraint).

In the context of generation planning under conditions of uncertainty regarding the availability of the generation fleet that supplies demand, the production of each generator results from a statistical analysis determined by the distribution functions that characterize the random behavior of demand and of each unit in the generation fleet.

The author, in the article "Electricity Markets Price Projection: An Innovative Approach for Risk Assessment Based on a Convolution Algorithm. ERCOT Case Study," presents a new methodology for the market prices projection under conditions of uncertainty, where market prices are determined by a recursive procedure applying a convolution algorithm to the distribution functions of demand and the generation fleet [15] (**Figure 8**).

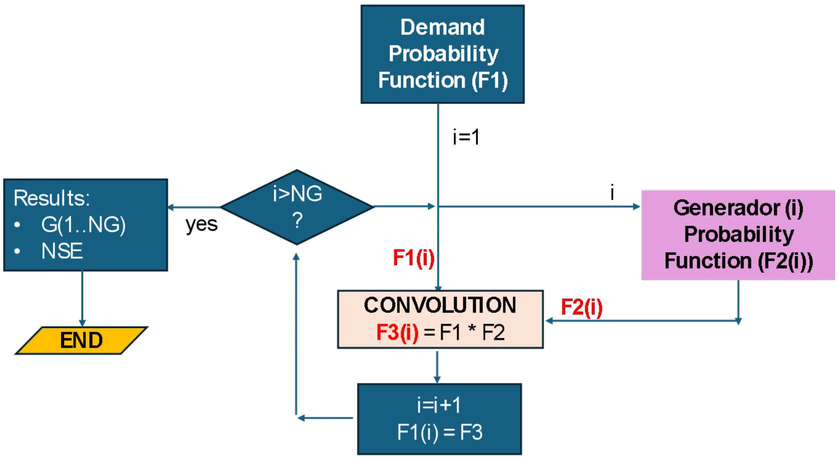

Figure 8. Market Prices projection using the convolution algorithm.

In each recursion, the production of each generator is determined. The NSE energy is equal to the resulting net demand after the dispatch of all generators.

$$F_3 = F_1 - F_2$$

$$f_3 = f_1 * f_2$$

$$f_3(z) = \sum_x f_1(x) \cdot f_2(z - x)$$

where:

f_1, f_2, f_3 are the density functions of F_1, F_2, F_3 respectively,

$*$ is the convolution operator:

$$ND(0) = \sum_{j=1}^{DMax} j \times f_0(j)$$

$$ND(i) = \sum_{j=1}^{DMax} j \times f_i(j)$$

$$G(i) = ND(i-1) - ND(i)$$

$$\text{NSE} = \sum_{j=1}^{DMax} j \times f_{NG}(j)$$

Knowing the energy production of each generation unit and the probable NSE, the total supply cost ($TC) is determined. Increasing demand determines the marginal cost.

$$\$G(i) = \text{VPC}(i) \times EG(i)$$

$$\$\text{NSE} = \text{VOLL} \times \text{NSE}$$

$$\$\text{TC} = \sum_{i=1}^{NG} \$G(i) + \$\text{NSE}$$

The concepts indicated above can be used to determine the production of the generators under conditions of uncertainty in the availability of the generating units and the average market prices of a period of interest.

5. Description of the Hybrid Project

As previously mentioned, for a generation project to be economically viable in a competitive electricity market, and therefore part of the optimal expansion plan, the spot market energy prices at which generators' energy production is remunerated must cover the project's investment and operating costs.

The Hybrid Project being evaluated consists of i) a solar photovoltaic (PV) generator, ii) a hydrogen production and storage facility comprising an electrolyzer and salt dome storage, and iii) a thermal power plant (TPP) that uses the stored H_2 as fuel. The solar PV generator, the electrolyzer, and the TPP have a combined installed capacity of 100 MW.

The TG uses the stored H_2 to generate energy during periods of high demand on the electrical system, contributing to the security of supply. The following figure (**Figure 9**) shows the expected H_2 and electricity production for a project with an installed capacity of 100 MW. The project produces 7,350 t of H_2 annually for industrial use and 85.8 GWh of electricity (0.31 PJ). The overall project efficiency is 27% (delivery energy/available energy = (0.88 + 0.31)/(3.15 + 1.26)), and the electrolyzer utilization factor is 80%.

The thermal plant (TG) is expected to produce energy during the 858 h of the year when market energy prices (MPs) are at their highest. The project will purchase energy during the 3,500 h of the year when MPs are at their lowest (and there is available power in the electrolyzer not being used to produce H_2 with energy supplied by the solar generator). The following figure (**Figure 10**) shows the monthly operation (buy and sell energy). For the thermal generator (TG), the efficiency (γ) of the conversion process is expected to be on the order of (γ = sell energy/buy energy) ≈ 24.5% (= 0.31/1.26).

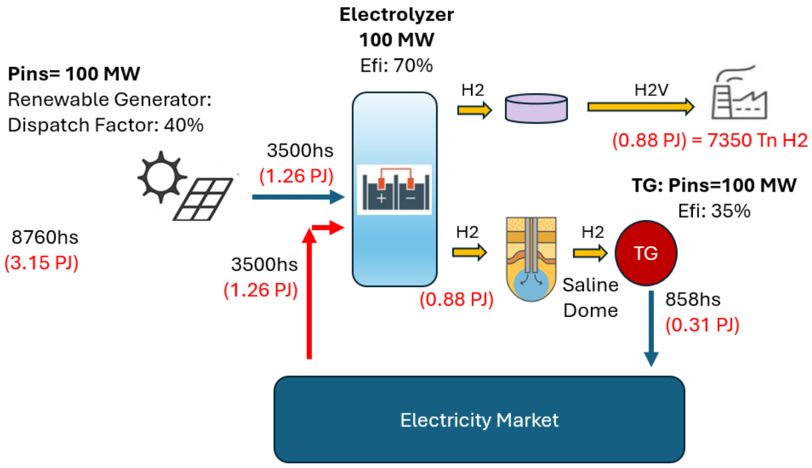

Figure 9. Hybrid Project. Annual energy balance.

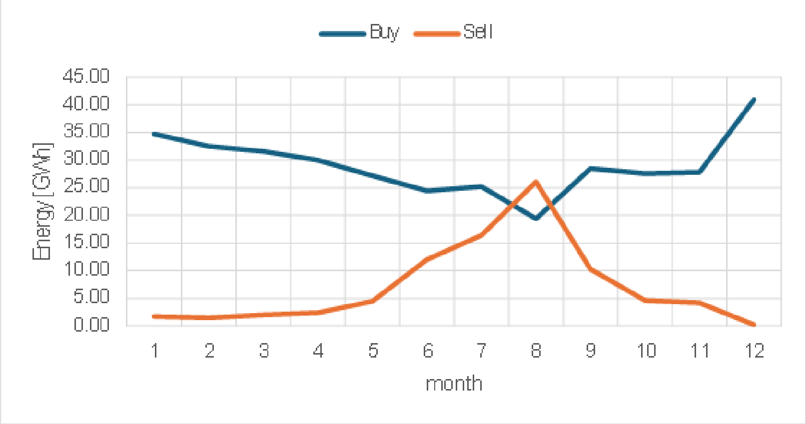

Figure 10. Hybrid Project. Monthly buy and sell energy in the electricity market.

A salt dome is required to store H_2 during periods of the year with low MPs for later use in generating electricity during periods of the year with high MPs.

The required H_2 storage capacity is estimated at 4,500 t of H_2. The following figure (**Figure 11**) shows the evolution of the volume of H_2 stored throughout the year. H_2 is primarily stored in winter months (from November to May) for later use during the summer months (June to August). Storage is minimal during September and October to allow for maintenance tasks.

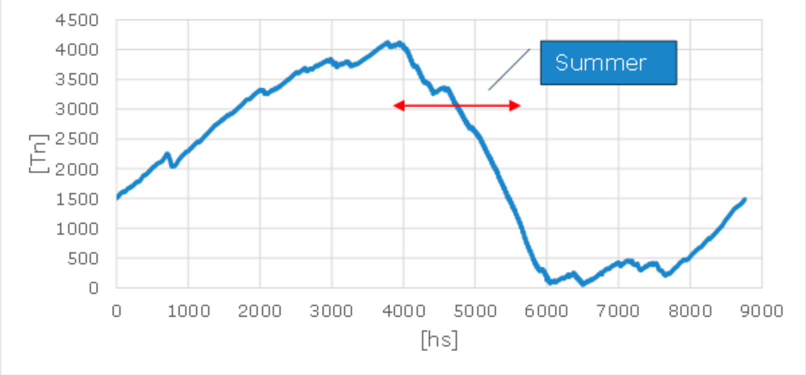

Figure 11. H_2 storage in a salt cavern. Intra-annual variation.

6. Economic Feasibility Analysis

6.1. Hourly Market Prices

The Hybrid Project being evaluated is assumed to be located in the state of Texas, USA, which has great potential for the development of H_2 storage projects in salt domes [16].

The hourly market prices considered to evaluate the economic feasibility of the Hybrid Project correspond to those recorded in the ERCOT in 2023, as shown in **Table 2**, which are considered representative of prices under economic equilibrium conditions [17,18].

Table 2. Locational Marginal Prices (LMPs) HUB HOUSTON—Year Average (USD/MWh).

Year	LMP (USD/MWh)
2023	57.07
2024	26.51
2025	34.46

Note: In the years 2025 and 2026, market prices were low, and therefore, they are not considered representative of prices compatible with the economic equilibrium of the market.

In the Texas Electricity Market, the spot market price of energy includes the component associated with the deficit risk discussed in the previous section [19].

For this purpose, the Operating Reserve Demand Curve (ORDC) is defined as shown in the following figure (**Figure 12**). The ORDC curve takes values greater than zero when the system reserve is less than 7,000 MW, reaching values of 5,000 USD/MWh when the reserve is less than 3,000 MW [20].

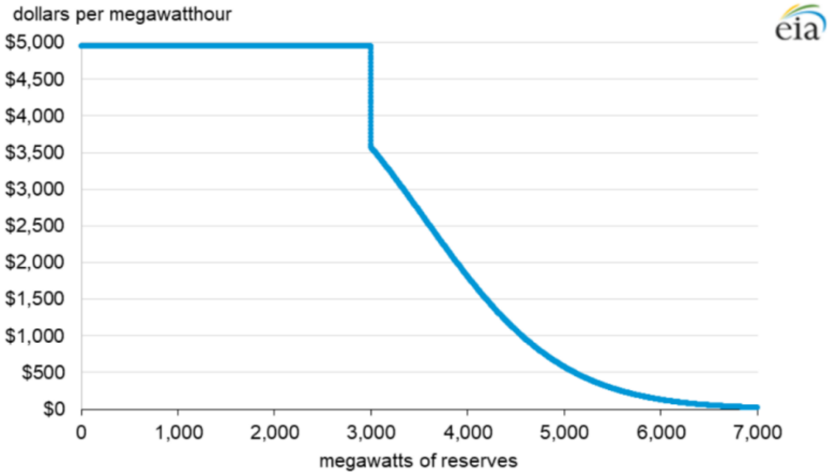

Figure 12. ERCOT TX. Operating Reserve Demand Curve (ORDC).

ERCOT determines generation dispatch using the available capacity and prices offered by generators. Every hour, the generators that offer the lowest prices are dispatched until the hourly demand is met, complying with operational safety criteria and systems constraints.

As a result of the operation, ERCOT determines the market prices (MP) for the Day Ahead Market (DAM) and the Real Time Market (RTM). The MP in each hour is equal to the price offered by the generator with the highest price offered that was dispatched in the hour (marginal offer) plus the value of the ORDC corresponding to the existing reserve in each hour.

In December 2025, ERCOT introduced regulatory changes incorporating the cost of reserves (activation probability) into the determination of the economic dispatch of generation and market prices. This allows for better dispatch of energy storage facilities (BESS) without significant changes in market prices determined using the ORDC.

The reform introduces the Ancillary Service Demand Curve (ASDC) as slices of reserves under the ORDC curve, with the highest-valued Ancillary Services being Regulation-Up Service (Reg-Up), followed by Responsive Reserve

Service (RRS), followed by ERCOT Contingency Reserve Service (ECRS), and lastly Non-Spinning Reserve Service (Non-Spin).

The graphic below (**Figure 13**) illustrates the hierarchy of the individual ASDCs. The graphic also illustrates how scarcity pricing and the value of reserves are set by individual ASDCs as the quantity of reserves diminishes.

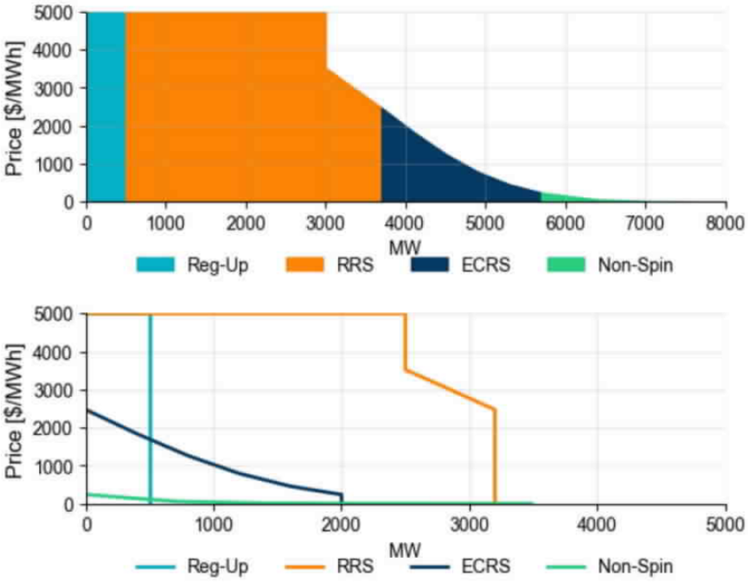

Figure 13. ERCOT. Reserves cost components.

The Electric Reliability Council of Texas (ERCOT) provides electricity service in Texas (USA) to more than 90% of the state's consumers. The demand of TX in 2023 was 547.3 TWh. To supply the demand, TX has an installed generation capacity of 155 TW (Dec 2023). The generation capacity is mainly thermal plus renewable generation. The main fuel used for thermal generation is natural gas, abundant in the state of TX. The following figure shows the generation capacity by type (**Figure 14**).

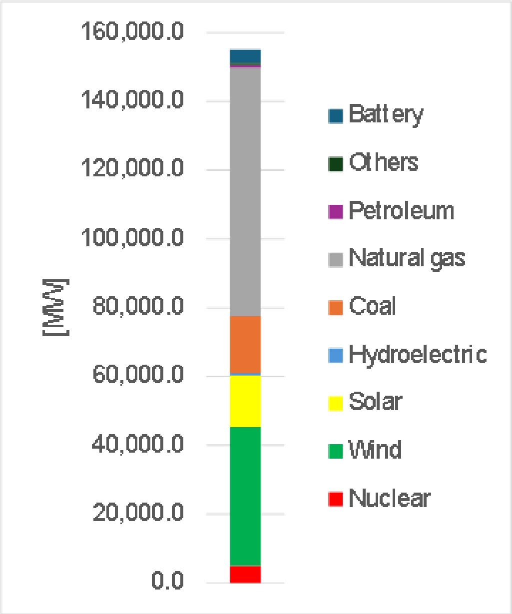

Figure 14. TX. Installed Capacity by type (Dec 2023).

Source: EIA.

In the ERCOT, Market Prices typically show seasonal variations associated with variations in demand; they are maximum in the summer months when system demand is maximum. The following figure (**Figure 15**) presents the average monthly market prices, showing the two components that make up the price of energy. In the summer months, generation reserves are reduced due to higher demand, resulting in high values for the component associated with supply risk (ORDC).

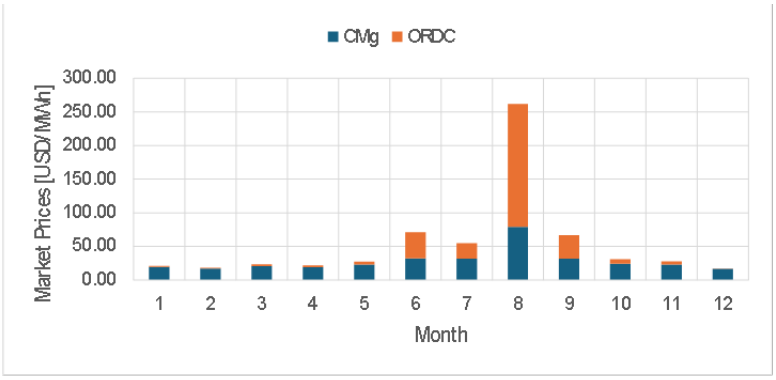

Figure 15. ERCOT. Market prices in 2023.

As a result of ORDC prices, the price duration curve for 2023 shows very high prices for at least 500 h/year. The high participation of renewable generation produces very low prices for at least 3,000 h/year [21] (**Figure 16**).

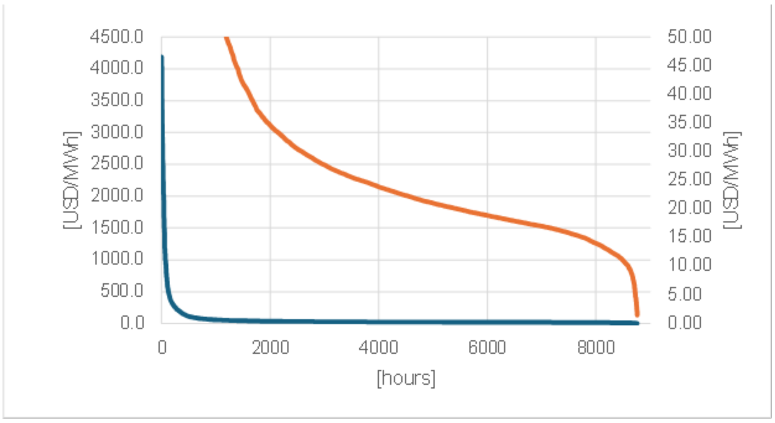

Figure 16. HUB HOUSTON. Market prices duration curve in 2023.

Note: The two curves show the locational marginal price (LMP) values on two scales to facilitate observation. The blue curve corresponds to the LMPs on the left scale. The red curve corresponds to the LMPs on the right scale.

The average annual MPs in 2023 cover the investment and operating costs of the new generators that allow for supplying current and future demand at minimum cost. The expansion of the generation fleet is expected to be based primarily on natural gas-fired Combined Cycle (NG-CC) thermal power plants, renewable wind and solar generation, and energy storage systems (BESS).

The levelized costs (CAPEX + OPEX) of these technologies are as follows [22,23]:

- NG-C: 57.0 USD/MWh (NG price = 3.0 USD/MBTU);
- Renewable (Solar, Wind) = 45.0 USD/MWh;
- VOLL = 5,000 USD/MWh.

6.2. Energy Marginal Rent

The energy marginal rent of the Hybrid Project results from the difference between the revenue from sales of generated energy and the cost of purchasing the energy required for its conversion to H_2.

Since energy purchases and sales occur at different times, the marginal rent is determined within a one-year timeframe. The marginal rent is obtained as a result of the operation (dispatch) of the Hybrid Project within this timeframe.

$$\mathrm{MR}[\$] = \sum_{h=1}^{h=T} Eg_h \times MP_h - Ed_h \times MP_h$$

$$\sum_{h=1}^{h=T} Eg_h = \gamma \times \sum_{h=1}^{h=T} Ed_h$$

Where:

h: each hour of the operational windows T: (=8,760 h);

Eg: Generated energy;

Ed: Demanded energy;

MP_h: Market Energy price;

γ: Conversion efficiency.

Figure 17 below shows the duration curve of the LMPs, year 2023 (blue line). The two figures show the same LMPs with two different scales. The figure also shows (red dashed lines) the average selling and purchase prices. The average selling price of energy (captured price) is approximately 360 USD/MWh, considering the 858 h of the highest price of the year. The average purchase price is approximately 20.0 USD/MWh, considering the 3,500 h of the lowest price of the year, in which there is available capacity in the electrolyzer (not used by the GH_2 process).

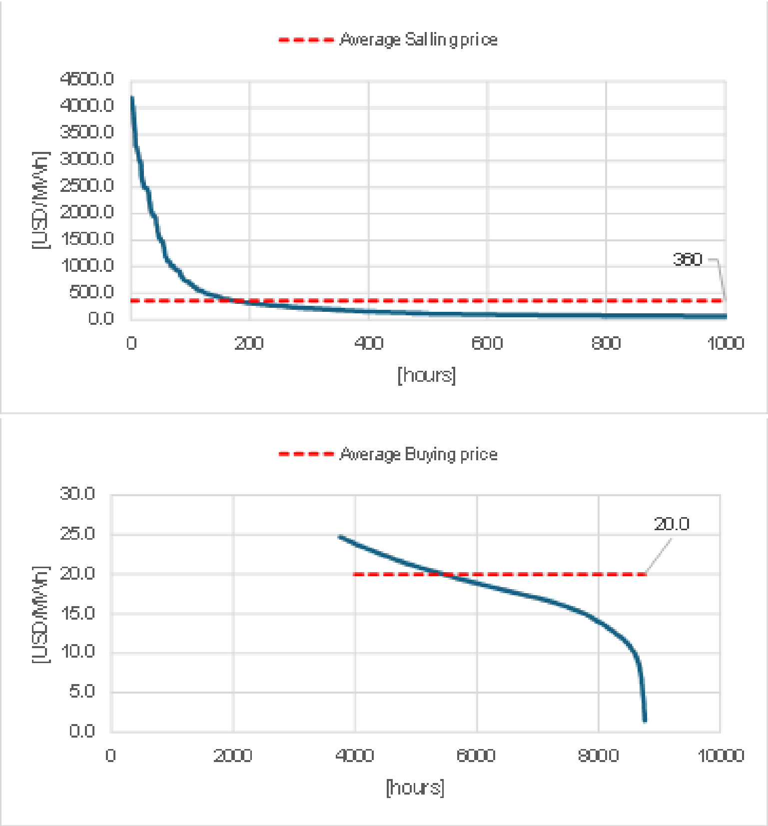

Figure 17. Selling and buying energy prices.

For the Hybrid Project, the annual marginal rent (MR) result:

MR[$] = 100 MW × (858 h × 360.0 USD/MWh − 3,500 h × 20.0 USD/MWh) = 23.9 million USD/year
= 278 USD/MWh (generated)

6.3. Investment and Operating Costs

The main cost components of the Hybrid Project include:

- Investment in the TG generator.
- Investment in the expansion of the Transformer Station (a new high-voltage (HV) connection bay and transformer).
- Investment in the salt dome required for H_2 storage.
- Investment associated with H_2 compression.
- O&M costs.

Note: The costs (capital and operating) associated with the solar generator and the electrolyzer are assumed to be recovered by the GH_2 project through the sale of H_2 production (7,350 t/year) to industrial consumers.

The assumed construction period is two years. The project's useful life is 30 years. The weighted average cost of capital (WACC) is estimated at 5% before taxes (real).

The main cost components are detailed below.

6.3.1. Thermal Generator (Gas Turbine—TG)

The TG generator under consideration consists of a generating unit with the characteristics indicated in the following table (**Table 3**).

Table 3. TG generator, main technical characteristics.

Parameter	Unit	Value
Factory	—	Siemens
Model	—	SGT6-2000E
Capacity	MW	117
Efficiency	—	35.4%
Heat Rate	BTU/kWh	9,638

Source: Gas Turbine World Handbook (2022).

The all-in capital expenditure (CAPEX) of the generator is estimated at USD 700/kW. This value is increased by 20% to account for conversion costs to use H_2 as fuel.

Given the generator's low dispatch factor (approximately 10%), it is estimated that over the evaluation period (30 years), the generator will have accumulated approximately 27,000 operating hours. Therefore, major maintenance costs are not included in the O&M costs, and it is assumed that the generator can be used for other applications (outside the evaluation period) with a final value of 50% of the initial CAPEX.

6.3.2. Salt Dome Storage

The capital expenditure (CAPEX) for hydrogen storage in salt domes depends on factors such as storage capacity, cavern depth, and compression and injection infrastructure [24,25].

According to available references, the installed capital cost of underground salt caverns decreases appreciably from approximately \$95/kg-H_2 for m = 100 t-H_2 stored to approximately \$19/kg-H_2 for m = 3,000 t-H_2 stored. The following figure (**Figure 18**) shows the capital cost function.

The project under evaluation requires an estimated H_2 storage capacity of 4,500 t/year. For this capacity, the estimated CAPEX is USD 25/kg-H_2, a value that includes a 20% margin for other costs.

6.3.3. Connection to the Transmission System

The Hybrid Project will share the transmission system connection with the solar generator. This aims to minimize investment costs.

The additional equipment required for the TG generator connection includes a transformer (medium-voltage/high-voltage (MV/HV)), bus extension, and a connection bay.

The estimated CAPEX for this equipment is USD 3.0 million.

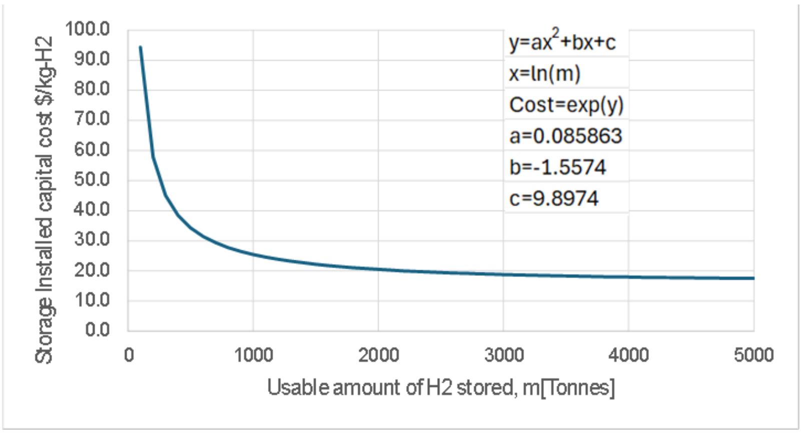

Figure 18. CAPEX storage in saline domes.

6.3.4. O&M Costs

O&M costs represent a significant portion of the total costs, primarily due to high fixed costs (labor costs) and a low energy production factor (10%).

Labor costs can be minimized by considering the personnel required for the entire project (solar generation, H_2 production, plus the Hybrid Project).

The estimated incremental O&M costs for the Hybrid Project are USD 30/kW-year.

6.3.5. Total Cost

The following table (**Table 4**) and figure (**Figure 19**) show the total cost of the Hybrid Project and its components. The Net Present Value (Discount Rate 8.5%, 30 years) of the total cost is USD 218.4 million, of which 54% corresponds to the processes associated with H_2 storage and compression, 33% corresponds to the TG investment cost, and 13% to O&M costs.

Table 4. Hybrid Project. Main project cost (CAPEX + OPEX).

CAPEX	NPV (Million US$) (1)	US$/MWh (2)
H_2 Compression	17.7	22.58
H_2 Storage	99.7	127.01
TG	71.0	90.54
HV Connection	2.5	3.25
Total CAPEX	191.0	243.38
Total OPEX	27.5	34.99
Total Cost	218.4	278.37

Note: (1) Discount Rate 8.5%; (2) Costs per generated energy (US$/MWh).

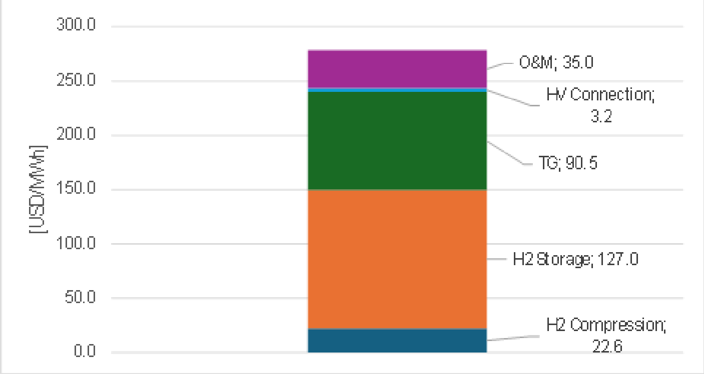

Figure 19. Hybrid Project. Cost components.

6.4. Profitability

Considering the project's cash flow (marginal income minus investment and operating costs), the project's Internal Rate of Return (IRR) result is 8.5% before taxes (real).

7. Conclusions

The energy transition will pose significant challenges in terms of investment in new generation capacity, seeking to transform the energy matrix towards a path of progressive decarbonization.

In this context, H_2, produced from renewable sources, can be used as a fuel for industrial applications, replacing the use of fossil fuels. It is estimated that in this way, H_2 will gradually become a vector that contributes significantly to achieving the clean energy goals set by countries.

In electricity generation, the potential integration of H_2 as an alternative energy source currently appears to be limited. The main reasons are high investment costs and low production process efficiency.

One alternative to minimize costs is to integrate H_2 production for industrial use with an electricity generation via a Hybrid Project that utilizes the remaining capacity of the electrolyzer, thereby maximizing its utilization factor.

The low efficiency of the process can be offset by energy arbitrage between periods of the year with significant differences in electricity prices. This requires H_2 storage capacity in salt caverns. The resulting production factor of the project makes it a peak-load unit that competes directly with conventional diesel-fired thermal power plants, contributing to the security of supply for demand.

The aforementioned operating conditions (peak-load unit) mean that for the project to be economically viable, spot market energy prices must reflect the marginal cost of generation plus the marginal cost of probable NSE (due to generation failures) for each operating state.

The Hybrid Project evaluated shows that under market equilibrium conditions, the project is competitive without requiring subsidies, and therefore can be part of the generation mix that allows supplying demand safely at minimum cost.

As a peak-load generator, the greatest risks of the Hybrid Project are associated with the occurrence of periods of low reserves and, consequently, high energy prices in the spot market.

As part of the energy transition, a strong expansion of renewable generation (wind, solar PV) is expected, leading to greater volatility in energy production and making periods of low generation reserves likely due to the intermittency of renewable generation. This will incentivize storage requirements, with H_2 storage in salt caverns being one alternative for use as backup for conventional generation.

Alternatives to mitigate market risks include: i) the existence of a Capacity Market where the project sells Firm Capacity, ii) supply contracts signed with entities representing consumers to minimize the risks of high energy prices during periods of scarcity, iii) the provision of Ancillary Services using the rapid response of the TG units, and iv) minimizing costs associated with the curtailment of renewable generation.

The investment risk is primarily associated with the adaptation and maintenance of the salt dome. This storage capacity can also be used for H_2 intended for industrial use, thus mitigating risks. The investment risk associated with the thermal generation unit (TG) is considered minimal since the generator can be used for other purposes using fossil fuels.

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AI Use Statement

The author declares that no artificial intelligence (AI) tools were used in the preparation of this manuscript.

Appendix A. Cost Recovery Theorem

- **Postulate**

The cost recovery theorem states that an optimally designed generation fleet allows i) for meeting demand at minimum cost, and ii) all generators recover their total (fixed plus variable) costs through the sale of energy at marginal cost [8].

$$Incomes = Eg \times CMg = Eg \times (CMg - V) + Eg \times V$$

$$Incomes = Eg \times \mathrm{MR} + \ Eg \times V$$

Where:

V: Variable production cost;

MR: Marginal Rent;

Eg: Energy generation.

The second term in the above expression represents the variable cost associated with energy production. Therefore, for the cost recovery theorem to hold, the first term (Marginal Rent—MR) of the equation must cover the fixed costs associated with investment and operation.

- **Optimal Planning**

Determining the optimal generation expansion plan requires defining a procedure to determine the capacity of each generating unit included in the expansion plan.

The procedure is illustrated in the following figure.

The required information includes the hourly demand (load duration curve), the fixed (F) and variable (V) costs corresponding to the candidate generating units, and the VOLL value.

By comparing costs, the time during which each generating unit is dispatched and the time ($T0$) during which the NSE exists are determined. Technology $G1$ is dispatched during the time interval ($T1$). Technology $G2$ generates continuously.

The time intervals $T0$ and $T1$ result from the cost comparison.

$$\mathrm{VOLL} \times T0 = F1 + V1 \times T0$$

$$T0 = \frac{F1}{\mathrm{VOLL} - V1}$$

$$F1 + V1 \times T1 = F2 + V2 \times T1$$

$$T1 = \frac{F2 - F1}{V1 - V2}$$

By projecting these time intervals ($T0$, $T1$) onto the load duration curve, the optimal Installed Capacity (P) for each of the generators ($G1$, $G2$) is determined.

Given the Installed Capacity of each generator ($P1$, $P2$) and their respective variable production costs ($V1$, $V2$), the minimum-cost generation dispatch by merit order and the NSE (Net Service Energy) are determined for each hour. In each hour, the marginal cost is equal to the variable cost (V) of the highest variable-cost generating unit operating during that hour. In hours when demand is not met, resulting in an NSE, the marginal cost is equal to the VOLL.

The following figure presents an example. For each generator, its respective fixed costs ($F1$, $F2$) and variable costs ($V1$, $V2$) are indicated. The VOLL value is also shown.

The optimization procedure yields the optimal power outputs for each generator ($P1$, $P2$). The economic generation dispatch results in the energy generated ($Egen$) by each generator. The figure also indicates the time intervals $T0$ and $T1$.

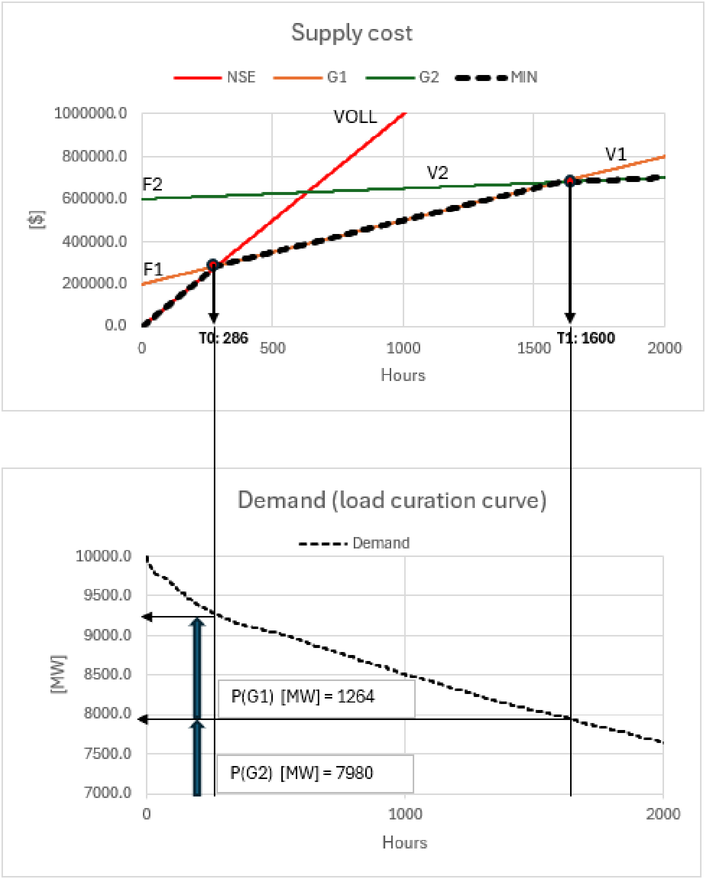

Figure A1. Determination of optimal capacity mix.

Table A1. Example of the generation planning process.

Generator	Fixed Cost (F) ($/MW-y)	Variable Cost (V) ($/MWh)	Installed Capacity (MW)	Generation (MWh)
$G1$	200,000	300	1,264	1,156
$G2$	600,000	50	7,980	57,703

Metric	Unit	Value
VOLL	($/MWh)	1,000
NSE	(MWh)	86
$T0$	(h)	286
$T1$	(h)	1,600

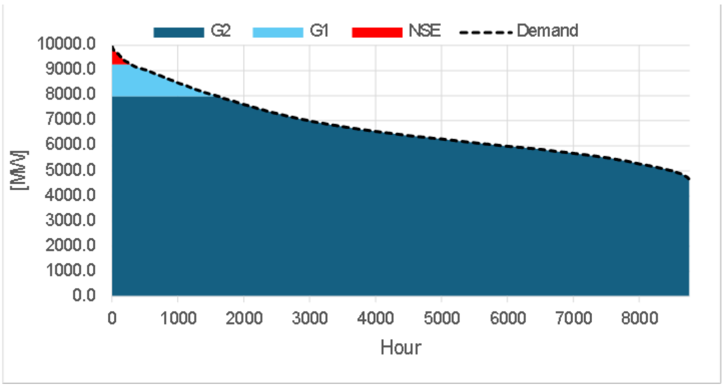

Figure A2. Minimum cost generation dispatch.

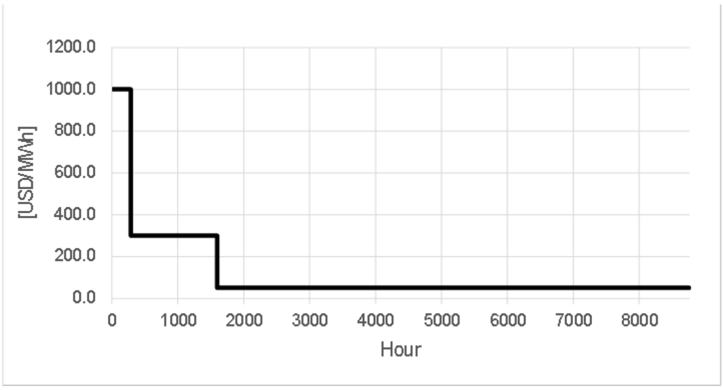

Figure A3. Market prices duration curve.

- **Verification**

The revenues of generators ($G1$, $G2$) from energy sales result in each hour of period T from the production of the generators valued at CMg.

$$Incomes(G1)\ [\$] = \sum_{h=1}^{h=T} CMg(h) \times Eg(1)$$

$$Incomes(G2)\ [\$] = \sum_{h=1}^{h=T} CMg(h) \times Eg(2)$$

The total costs incurred by generators ($G1$, $G2$) result from the sum of fixed costs plus variable costs.

$$Total\ Cost(G1)[\$] = F1 \times P1 + V1 \times Eg(1)$$

$$Total\ Cost(G2)[\$] = F2 \times P2 + V2 \times Eg(2)$$

Generator $G1$ produces energy in period $T1$ and obtains an MR in period $T0$.

$$\text{MR1} = P1 \times T0 \times (\text{VOLL} - V1) = P1 \times F1$$

Generator $G2$ obtains an MR in period $T1$.

$$\text{MR2} = P2 \times T0 \times (\text{VOLL} - V2) + P2 \times (V1 - V2) \times (T1 - T0) = P2 \times F2$$

The following table shows the annual revenues (operational incomes) and costs determined for each generator. It can be seen that, for each generator, the revenues equal the sum of its costs.

Table A2. Operative results.

Generator	Income (Million $)	Costs		Net Result (Million $)
		Fix (Million $)	Var (Million $)	
$G1$	600	253	347	0
$G2$	7,673	4,788	2,885	0

It is therefore proven that, for an electrical system where the generation expansion plan meets demand at minimum cost, all generators recover, through the sale of energy valued at the marginal cost (CMg), their total fixed costs plus variable costs.

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