PAPER • OPEN ACCESS

Techno-economic Analysis of Optimal Grid-Connected Renewable Electricity and Hydrogen-to-Power Dispatch

Techno-economic Analysis of Optimal Grid-Connected Renewable Electricity and Hydrogen-to-Power Dispatch

Raheel A. Shaikh, Yogesh Pipada Sunil Kumar, Shah Mohammad Mominul Islam, and Derek Abbott

School of Electrical & Mechanical Engineering, The University of Adelaide, SA 5005, Australia

E-mail: `raheel.shaikh@adelaide.edu.au`

Abstract. One of the significant challenges in renewable integration is balancing supply and demand. The variability in generation and demand forces the grid to experience significant market price volatility. Moreover, electricity curtailment is adhered to during low-demand periods. Hydrogen Energy storage systems (HESS) can provide power dispatch flexibility and facilitate the reduction in curtailment. Unlike other storage systems such as batteries, the energy and power capacities for HESS design can be decoupled, resulting in a long-duration storage solution. In our paper, we perform electricity dispatch optimization from renewable sources such as solar and wind to the electricity market, where hydrogen is optimally produced using electrolysis, stored during low electricity prices, and converted to electricity using fuel cells to support the grid. The capital cost optimization suggests high profits for investors leveraging market price volatility even with low HESS round-trip efficiency and high upfront costs.

1. Introduction

Increasing the integration of Renewable Energy Sources (RES) to reduce greenhouse gas emissions presents the difficulty of effectively aligning energy demand and supply. This is due to the unpredictable output of weather-dependent generators such as solar panels and wind turbines. Various strategies can be employed to address this issue, such as implementing energy storage systems, optimizing demand patterns, and enhancing the connectivity between different energy grids at a regional level [1]. While pumped hydro and batteries are the prevalent energy storage methods, they fall short in offering the extended storage capacity required for ensuring energy sufficiency. In contrast, the concept of power-to-gas-to-power (PtGtP), particularly hydrogen generation, has emerged as a promising avenue for more prolonged energy storage solutions (ESS) [2]. This approach not only addresses the challenge of long-term storage but also aligns with hydrogen's utilization in various chemical production processes such as ammonia and methanol. Moreover, hydrogen's potential extends to mitigating carbon emissions from industries such as steel-making, which necessitates high-temperature processes, thereby presenting a comprehensive and versatile solution [3].

As renewable energy integration in Australia's National Electricity Market (NEM) expands, curtailment is growing. With renewables accounting for over 65% of South Australia's (SA) annual demand (and 30% of the NEM's demand), on average, 10% of RES-generated power in SA was intentionally unused in 2021 [4]. This trend is projected to intensify with the ongoing rise in renewable adoption in other regions of the country, leading to higher market price volatility. Furthermore, the cost of electricity exhibits significant fluctuations based on the time of day, primarily driven by shifts in consumer demand. Figures 1 and 2 are plotted for renewable energy curtailment and electricity price volatility in SA, respectively. Negative electricity prices prompt power generators to limit their electricity production. In this context, the hybrid RES-HESS configuration offers notable economic advantages. This setup enables renewable energy and grid imports to be channelled into the electrolyzer, serving as a flexible load during periods of unfavourable pricing characterized by generation surpassing demand.

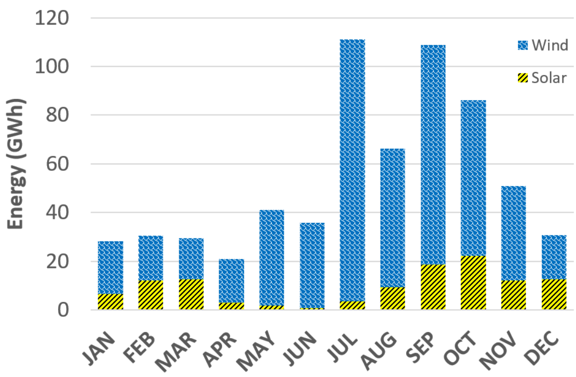

Figure 1: Electricity curtailment for solar (over 115 GWh) and wind (over 524 GWh) generation across South Australia (SA). Summer (Jun-Aug) and spring (Sept-Nov) experience the highest curtailment.

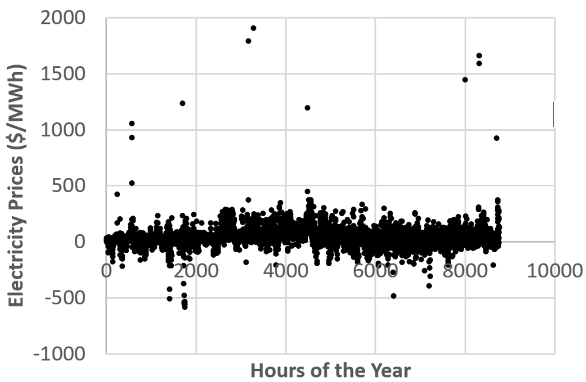

Figure 2: Electricity spot prices in South Australia (SA) in 2021. The maximum, minimum, and average prices are \$8595.52, −\$581.52 and \$50.70 per MWh respectively.

Renewable hydrogen can be generated through electrolysis, where water is divided using a proton-exchange membrane (PEM) electrolyzer. This hydrogen can then be stored underground (salt caverns) or above ground in tanks for subsequent on-site usage, either to transform it into electric energy or supply to relevant industrial consumers [5]. Due to ongoing climate commitments to reduce emissions, transportation and industrial sectors are expected to adopt hydrogen as a fuel, thereby increasing hydrogen demand. Presently, green hydrogen prices range from 6.08–7.48 A\$/kg for proton exchange membrane technologies [6] and are expected to reduce due to economies of scale.

Hydrogen-based energy storage systems (HESS) have been extensively investigated in recent years due to their notable advantages for storing large amounts of energy over extended periods [7]. In [8], the potential of wind-hydrogen systems is assessed to evaluate benefits in different grid configurations and hydrogen export for transportation. The hybrid system facilitates higher RES penetration by providing balancing services using fuel cells (FC). A techno-economic analysis using HOMER software for off-grid applications concluded that the addition of battery storage complements hydrogen storage to meet power and hydrogen demand and results in the lowest net present cost (NPC) in Australia [9]. Furthermore, HESS implementation is expected to avoid curtailment [10].

While several studies have been conducted to model off-grid (micro-grid) HESS, we demonstrate an opportunity for grid-connected HESS in this paper. A real-time optimizer to plan RES generation dispatch to the grid or onsite hydrogen generation plant is presented. The model includes electricity imported to produce additional hydrogen to maximize revenue, especially during low/negative electricity prices. The produced hydrogen is stored and later converted to power via FC to provide energy storage services to the grid. The model also considers an additional revenue component of hydrogen supply to the market. The model is implemented for a case study of South Australia (SA) grid prices, which is relevant to simulate optimum charging/discharging of storage based on maximizing profits.

The remainder of this paper is organized as follows. Section 2 summarizes the methodology, assumptions, and cases for our study, and Section 3 presents our simulation setup and results, while Section 4 provides a comprehensive discussion of findings. The study is concluded in Section 5 with identified future study areas.

2. Methodology & Assumptions

The system consists of wind and solar farms that generate electricity and HESS for hydrogen production, storage, and utilization. The HESS system includes an electrolyzer, compressors, heat exchangers, storage tanks, and fuel cells for converting hydrogen into electricity, as illustrated in Fig. 3.

The main goal is to optimize the utilization of wind and solar energy to maximize profits. This is achieved by selling electricity directly to the grid based on forecasted prices, producing hydrogen to sell in the hydrogen market, or converting hydrogen back into electricity via FCs to sell at favourable prices. Additionally, the system can import electricity during periods of negative pricing to increase electrolyzer throughput and hydrogen production. Inputs such as forecasted generation and electricity prices allow day-ahead dispatch optimization for maximum revenue.

For simulation purposes, we assume perfect foresight of generation and pricing data based on actual wind/solar farm and market data in South Australia (SA) for an entire year. The optimizer determines the optimal split of sending electricity to the grid (the National Electricity Market—NEM) vs storing it as hydrogen to later sell as electricity (via $\mathrm{PtH_2tP}$) or fuel. Furthermore, the system sinks the electricity during low demand and prices to produce additional hydrogen, helping to provide grid balancing services with an electrolyzer acting as a flexible load.

We consider a proton exchange membrane (PEM) electrolyzer due to its maturity with the additional potential for cost reduction and suitability for operation at acceptable efficiency with fluctuating power. The techno-economic parameters of the equipment considered are provided in Table 1.

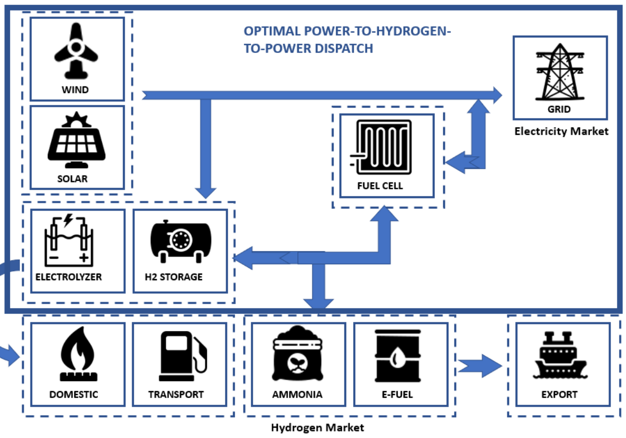

Figure 3: Overall supply chain for hydrogen production, utilization, and re-electrification. The Blue box signifies the scope of the optimization model, excluding the future hydrogen market.

To develop the optimization model, we define the following variables and index sets: $\mathcal{T}$ is defined as the index set of time with $t \in \mathcal{T}$ representing the time intervals and another index set $\mathcal{T}_1 = \mathcal{T}/\{1\}$. Here $E_t^{\mathrm{RN}}, E_t^{\mathrm{RE}}, E_t^{\mathrm{RX}} \in \mathbb{R}_+$ are the renewable energy allocated to NEM, electrolyzer and curtailment, respectively. Moreover, $E_t^{\mathrm{NE}}, E_t^{\mathrm{FN}} \in \mathbb{R}_+$ are defined as the energy imported from NEM to electrolyzer and energy exported from the FC to NEM respectively. Finally, $E_t^{\mathrm{ES}}, E_t^{\mathrm{SF}}, E_t^{\mathrm{SH}}, \mathrm{SOH_t} \in \mathbb{R}_+$ are defined for the hydrogen equivalent energy output from

Table 1: Technology costs in Australian dollars (AUD), are adapted from [6] and [11].

Technology	CapEx (\$/kW)	O&M Fixed (\$/kW-yr)	Life (years)	Efficiency (%)
Wind	1913	35	20	-
Solar	1241	20	20	-
Electrolyser	1450	24	10	70
Fuel Cell	1000	20	10	70
Inverter	10	0	20	100

the electrolyzer to storage, from storage to FC, from storage to hydrogen market (in MW) and state of hydrogen capacity in the storage tank (in MWh) respectively.

Additionally, we define indicator variables $b_t^{\mathrm{ES}}, b_t^{\mathrm{RE}}, b_t^{\mathrm{RX}} \in \{0, 1\}$ such that $b_t^{\mathrm{ES}} \iff \mathrm{SOH_t} = \mathrm{SOH_{max}}$; $b_t^{\mathrm{RE}} \iff E_t^{\mathrm{RE}} = E_{\max}^H; b_t^{\mathrm{RX}} \iff E_t^{\mathrm{RX}} > 0$. Here, $E_{\max}^H$ is the maximum input and output of the HESS in MW, and $\mathrm{SOH_{max}}$ is the maximum capacity of the storage tank in MWh. These are implemented using appropriate big-M formulations. Let us define the decision set as $\mathcal{X}$, which contains all the above-defined variables.

The parameters used for this simulation $E_t^R, \lambda_t^N, \lambda_t^H$ are the forecasted renewable generation in MW, electricity spot prices from the NEM and the green hydrogen market prices in \$/MWh. Thus, we propose the mixed integer linear programming (MILP) problem shown in Eqs. (1)–(8). This problem aims to optimize the allocation of renewable generation to maximize revenue obtained from the NEM and hydrogen markets,

$$\max_{\mathcal{X}} \sum_{t \in \mathcal{T}} \left[\lambda_t^N \cdot \left(E_t^{\mathrm{RN}} + E_t^{\mathrm{FN}} - E_t^{\mathrm{NE}} \right) + \lambda_t^H \cdot E_t^{\mathrm{SH}} \right]. \tag{1}$$

Subject to,

$$E_t^R = E_t^{\mathrm{RE}} + E_t^{\mathrm{RN}} + E_t^{\mathrm{RX}} \quad \forall\, t \in \mathcal{T}, \tag{2}$$

$$E_t^{\mathrm{ES}} = \eta^E \cdot \left(E_t^{\mathrm{NE}} + E_t^{\mathrm{RE}} \right) \Delta t \quad \forall\, t \in \mathcal{T}, \tag{3}$$

$$\mathrm{SOH}_t = \mathrm{SOH}_{t-1} + E_t^{\mathrm{ES}} \; - \left(E_t^{\mathrm{SF}} + E_t^{\mathrm{SH}} \right) \quad \forall\, t \in \mathcal{T}_1, \tag{4}$$

$$E_t^{\mathrm{FN}} = \eta^F \cdot E_t^{\mathrm{SF}} \quad \forall\, t \in \mathcal{T}, \tag{5}$$

$$b_t^{\mathrm{RX}} = b_t^{\mathrm{RE}} \vee b_t^{\mathrm{ES}} \quad \forall\, t \in \mathcal{T}, \tag{6}$$

$$E_t^{\mathrm{RE}}, E_t^{\mathrm{FN}}, E_t^{\mathrm{NE}} \leq E_{\max}^H, \tag{7}$$

$$\mathrm{SOH_t} \leq \mathrm{SOH_{max}}. \tag{8}$$

Equation (1) represents the revenue obtained from the NEM and hydrogen markets. Eq. (2) is the allocation of renewable generation (solar and wind) at t across the NEM, storage or curtailment or the energy balance constraint at the renewable asset. Eqs. (3) , (4) and (5) specify the operational constraints of the electrolyzer, storage tank, and fuel cell respectively with η^E, η^F signifying efficiencies of electrolyzer and FC, respectively. During negative price periods, it is favourable to curtail all renewable energy and buy electricity from the NEM to charge the SOH of the HESS. However, the purpose of the HESS is to store this renewable energy and produce green hydrogen. Hence, using Eq. (6)-(8), we impose that the renewable energy must be curtailed if the storage tank is full or the input energy from renewable asset to the electrolyzer has reached the electrolyzer's maximum limit.

3. Simulation and Results

This paper demonstrates the utility of HESS and renewable energy to perform arbitrage. However, since green hydrogen markets are still in nascent stages, the pricing is subject to change significantly in the near future. Thus, to avoid speculation, we remove this market from our optimization.

3.1. Simulation Setup

To demonstrate the utility of arbitrage, we develop three simulation case studies: 1) RES without HESS; 2) RES with HESS, where HESS only exports to NEM; and 3) RES with HESS, where HESS imports and exports from NEM. For the RES, we consider a combination of both solar and wind generators and obtain data from a real-world solar farm and wind farm producing 239.2 GWh and 334.6 GWh, respectively, to simulate their operation. Note that SA electricity price data for the same period is used to calculate the revenue (Refer Fig. 2). We assume the same size of HESS for cases 2 and 3 for comparison, which are $E^H_{\max} = 200$ MW, $\mathrm{SOH}_{\max} = 4,000$ MWh, i.e., storage with energy to power ratio (EP) of 20 hrs. Additionally, we perform a sensitivity analysis for case 3 by varying $E^H_{\max}$ and $\mathrm{SOH}_{\max}$ to understand the effect of sizing of HESS on the overall profit.

For the techno-economic analysis, we use the prices specified in Table 1 for all the different asset components. In addition to this, we also consider the pricing of the storage system i.e., storage tank pipes and compressor, as $50 million for 2000 MWh of hydrogen storage. We also assume that for every additional 1000 MWh of storage capacity, the operator would have to spend $2 million for overall system and its appurtenances.

3.2. Results

The results comparing the three cases are tabulated in Table 2 , while capacity sensitivity results are shown in Fig. 4. With conservative technology cost assumptions, we achieved the overall profit of $56m for case 1 compared to $84.2m for case 3, while we find that HESS integration without grid import is not profitable due to high technology costs.

Furthermore, with the capacity sensitivity analysis, we realize almost linear profits for most cases except when the storage is sized at 2,000 MWh, whereby increasing electrolyzer size to 200–250 MW only makes economic sense. The sensitivity demonstrates that there is an optimum capacity mix required for the highest revenue, considering technology prices and forecasted market prices.

Parameters	Case 1	Case 2	Case 3
Revenue ($m)	481	1383	1479
Expenses ($m)	425	1394	1395
Profit ($m)	56.0	-11.2	84.2
Curtailment (%)	31.5	0	0.06

Table 2: Comparison between simulation cases

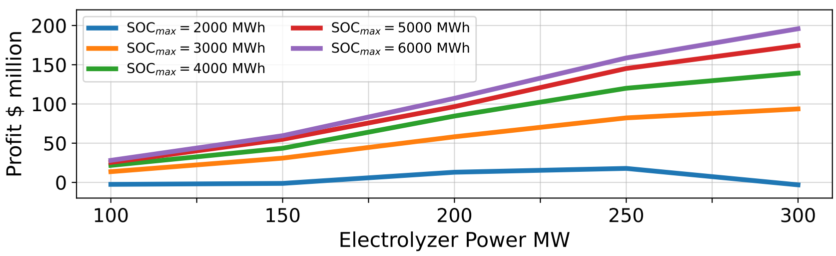

Figure 4: Capacity sensitivity analysis with variation in electrolyzer/ FC and storage tank capacities.

4. Discussion

Energy storage is critical for future energy transition as storage facilitates higher renewable integration and reduces energy curtailment. The HESS design allows the decoupling of the storage energy and power components and, therefore, is the most suitable candidate for long-term energy storage [12]. In this paper, we demonstrate a grid-connected hybrid RES-HESS configuration that leverages fluctuating electricity market prices to maximize profits by sinking the excess energy from the grid during low/negative prices.

The curtailment of electricity is significantly reduced from 31.5% to zero due to the energy time-shifting ability provided by HESS. Furthermore, The HESS produces an estimated 7,000 tonnes of hydrogen (234 GWh) annually and has an estimated water cost of half a million. The hydrogen produced in an electrolysis process is one part while oxygen is nine parts, and we anticipate higher profits from investments should oxygen be stored and sold as a commodity. With countries/regions achieving higher renewable integration, HESS provides long-duration capacity and can leverage the price variability induced due to RES uncertainty. We acknowledge, however, that higher storage integration will result in the smoothing of the demand curve and better management of RES resources, which will reduce the price volatility and, therefore, the profit opportunity for PtH_2tP in the electricity market. On the contrary, the hydrogen market is expected to grow with opportunities for local consumption and export to other countries, therefore, PtH_2 alone may be implemented for higher profitability.

5. Conclusion and Future Work

This study establishes a model integrating generation from solar and wind resources to produce hydrogen based on real-time hourly data. The scenarios for electricity-only and integrated electricity-hydrogen markets are simulated. It is evident that grid-connected HESS with electricity import is much more profitable than the RES system alone, with equipment capacities determining the final profits. Future work will include developing the optimum capacity model along with a real-time optimizer for implementation in existing plants.

Acknowledgment

The authors would like to acknowledge Sayed Nasrollah Hashemian Ataabadi is for his contributions. The authors are also grateful to The University of Adelaide and The Australian Government for Research Scholarships and Research Training Program (RTP) funding.

References

[1] Mlilo N, Brown J and Ahfock T 2021 *Technology and Economics of Smart Grids and Sustainable Energy* **6** 25
[2] Peter C, Vrettos E and Büchi F N 2022 *International Journal of Electrical Power & Energy Systems* **141** 108121
[3] Kim J, Sovacool B K, Bazilian M, Griffiths S, Lee J, Yang M and Lee J 2022 *Energy Research & Social Science* **89** 102565
[4] AEMO 2022 Quarterly energy dynamics `https://aemo.com.au/-/media/files/major-publications/qed/2021/q4-report.pdf?la=en`
[5] Vidas L and Castro R 2021 *Applied Sciences* **11** 11363
[6] Salmachi A, Hosseini T, Shaikh R A, Dinovitser A and Abbott D 2022 *International Journal of Hydrogen Energy* **47** 23710–23720 ISSN 03603199
[7] Abbott B D and Ieee F 2009 **97** 1931–1934
[8] Apostolou D and Enevoldsen P 2019 *Renewable and Sustainable Energy Reviews* 917–929 ISSN 18790690
[9] Abdin Z and Mérida W 2019 *Energy Conversion and Management* **196** 1068–1079 ISSN 01968904
[10] Zhang G and Wan X 2014 *International Journal of Hydrogen Energy* **39** 1243–1252 ISSN 03603199
[11] Graham P, Hayward J, Foster J and Havas L 2021 *CSIRO* 1–85 URL `https://publications.csiro.au/publications/publication/PIcsiro:EP2021-0160/SQgencost/RP1/RS25/RORECENT/STsearch-by-keyword/LISEA/RI1/RT6`
[12] Shaikh R A, Vowles D J, Allison A and Abbott D 2023 *IEEE Access* **11** 64201–64218 ISSN 21693536