The hydrogen Gulf: Quantitative supply chain optimisation for a trans-regional green hydrogen economy in the Gulf Cooperation Council (GCC)

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By

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Abstract

The Gulf Cooperation Council (GCC) region is exceptionally well positioned for large-scale green hydrogen development, combining among the highest global solar irradiance levels with strategically significant export access to both the Red Sea and Arabian Gulf maritime corridors. However, despite strong policy momentum and ambitious national decarbonisation targets, the systematic design of resilient, economically viable, and temporally robust green hydrogen supply chains (HSCs) in the GCC remains insufficiently addressed in the literature. Existing approaches are predominantly static, single-criterion, or single-country in scope, and fail to capture the dynamic interplay between evolving stakeholder priorities, multi-period technology maturation, and multi-objective trade-offs inherent in large-scale hydrogen infrastructure deployment. This thesis develops a multi-objective optimisation framework for green HSC design in the GCC, integrating Mixed-Integer Linear Programming (MILP) with an adaptive Analytic Hierarchy Process–Technique for Order Preference by Similarity to Ideal Solution (AHP–TOPSIS) methodology. The framework incorporates time-dependent stakeholder preferences and multi-period planning horizons to represent the evolution of technology performance, cost trajectories, and sustainability objectives under demand uncertainty. The model is applied to two regional case studies: Kuwait, analysed under a single-period static framework representing a 2050 planning horizon, and Saudi Arabia's Northwestern region (Al Jawf, Tabuk, Hail, and Al Madinah provinces; 477,089 km^2), evaluated under a dynamic multi-period framework spanning 2025 to 2060. Both cases assess alternative hydrogen production technologies (PEM, AEM, and alkaline water electrolysis), storage options (compressed gas tanks, cryogenic tanks and salt caverns), and transportation modes (compressed gas trucks, cryogenic trucks, and pipelines). Results indicate that production technology selection is the most demand-sensitive component of the supply chain. Alkaline water electrolysis is preferred under low-to-medium demand conditions due to operational stability and lower capital intensity, while PEM electrolysis becomes preferable under high-demand conditions in 2060, where sustained high utilisation enables its higher efficiency to be fully realised. Across both case studies, geological storage consistently dominates surface alternatives under all evaluated scenarios, with substantial performance margins in both MILP and TOPSIS frameworks. Pipeline transportation emerges as the preferred long-term transport mode, with increasing dominance at higher demand levels and under capital cost prioritisation, reflecting strong scale economies relative to cryogenic logistics.

Collectively, these findings support a regionally coordinated hydrogen infrastructure design, conceptualised as a GCC Hydrogen Corridor Architecture comprising a pipeline backbone and geographically distributed geological storage network. This framework highlights the potential efficiency gains from coordinated infrastructure development across GCC states, particularly through shared transport corridors, diversified storage siting, and spatial optimisation of production and demand centres.

The thesis contributes four principal advances: an integrated MILP- AHP-TOPSIS framework for hydrogen supply chain optimisation across multiple GCC contexts; the identification of regime-dependent technology optimality as a structural feature of hydrogen system design; a quantitative basis for assessing coordinated GCC hydrogen infrastructure at the regional scale; and a methodological demonstration that static and multi-period optimisation frameworks provide complementary insights into different dimensions of system behaviour under uncertainty.

Declaration

No part of this thesis has been submitted in support of an application for any degree or qualification of Brunel University London or any other University or Institute of learning.

Publications

[1] Olabi, Valentina, and Hussam Jouhara. "An assessment of current hydrogen supply chains in the Gulf Cooperation Council (GCC)." Energy 299 (2024): 131576.

[2] Olabi, Valentina, Abdulrahman Alhajeri, and Hussam Jouhara. "Designing a sustainable hydrogen supply chain network in the Gulf Cooperation Council (GCC) region: Multi-objective optimisation using a Kuwait case-study." International Journal of Hydrogen Energy 142 (2025): 994-1013.

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Nomenclature

GCC - Gulf Cooperation Council

HSC - Hydrogen Supply Chain

MILP - Mixed Integer Linear Programming

TOPSIS - Technique for Order of Preference by Similarity to Ideal Solution

AHP - Analytic Hierarchy Process

MCDM - Multiple Criteria Decision Making

PV - Photovoltaic

GW - Gigawatts

MW - Megawatts

CF - Carbon Footprint

GHG - Greenhouse Gas

GWP - Global Warming Potential

AEM - Anion Exchange Membrane

PEM - Proton Exchange Membrane

OPEC - Organisation of the Petroleum Exporting Countries

IRENA - International Renewable Energy Agency

IEA - International Energy Agency

LCOH - Levelized Cost of Hydrogen

LOHC - Liquid Organic Hydrogen Carrier

MGS- Master Gas System

HCA- Hydrogen Corridor Architecture

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1. Introduction

1.1 Background and Context

Today, 85 % of the world's total energy consumption is obtained from fossil fuels, such as natural gas, oil, and coal [1]. The release of greenhouse gas (GHG) emissions from the combustion of these energy sources, especially CO_2, which is known for its adverse environmental impacts, is prompting a global effort to obtain energy from novel sources. Particularly, in accordance with the Paris Agreement of 2015, the international community has been aiming to limit the global temperature rise to below 2°C above pre-industrial levels, with an ambition to cap it at 1.5°C [2]. As a result, there has been a growing global push to finding alternatives to fossil fuels in the transport sector, with renewables like solar and wind gaining significant traction. Because of this agenda, hydrogen has in recent years become a front-runner of the energy transition, due to its immense potential for electrifying the transport sector. In particular, 'green' hydrogen, which describes hydrogen powered entirely from renewable energy sources (i.e. solar and wind), has been subject to immense consideration due to its zero-emissions nature. Green hydrogen is produced via electrolysis by using an electric current to split water into hydrogen and oxygen, with no resulting GHG emissions [3]. As a result of this vast potential for global decarbonisation, several countries have actively invested in green hydrogen related policies and infrastructure, particularly in the Gulf Cooperation Council (GCC) region, which is widely known for its abundant solar resources.

While the GCC presents compelling comparative advantages for green hydrogen development, it is important to acknowledge certain limitations associated with its selection as the primary case study region. First, the GCC's current economic model is heavily reliant on hydrocarbon revenues, which creates structural inertia that may delay or constrain the pace of energy transition. Hydrocarbon export revenues accounted for between 39% and over 80% of total government revenues across GCC member states in recent years [4], and oil and natural gas account for almost all final energy consumption in the region [4]. The diversification of national energy portfolios towards renewables and hydrogen is therefore subject to significant political economy considerations that are not always captured in optimisation models. Second, the region's extreme climate conditions-characterised by high ambient temperatures (frequently exceeding 45°C in summer months) and significant dust accumulation-present operational challenges for solar photovoltaic (PV) installations and electrolyser performance that may reduce real-world efficiency below modelled values. Monthly, soiling losses of up to

10% of PV power output have been reported in GCC conditions [5], where median revenue loss due to soiling amounts to approximately 2.5% even under optimal cleaning schedules every five to six days [6]. Third, freshwater scarcity is a critical constraint in the GCC, as green hydrogen production via electrolysis requires approximately 28.6 litres of water per kg of hydrogen produced [7]. The purification of seawater for electrolysis introduces additional energy consumption. Although desalination is technically feasible, it adds cost and carbon intensity that must be incorporated into realistic supply chain assessments. Finally, while the GCC's regulatory and institutional frameworks are evolving rapidly, the absence of a unified trans-national energy governance structure means that cross-border infrastructure coordination remains subject to geopolitical complexities. These limitations are acknowledged in the design of this research and are discussed further in the relevant methodology and case study chapters.

The GCC comprises of Saudi Arabia, United Arab Emirates, Qatar, Kuwait, Oman, and Bahrain, and is home to vast comparative advantages to develop green hydrogen supply chains (HSCs), especially abundance in solar energy. Oman has the highest regional annual solar radiation of ~ 2500 kWh/m^2; United Arab Emirates (UAE) has the second highest at 2285 kWh/m^2, and Kuwait and Saudi Arabia have equal annual solar radiations of 2200 kWh/m^2 [8]. To compare, the average annual solar radiation globally lies between 640- 2,400 kWh/m^2 [9], so the region lies on the higher end of global averages, thus highlighting their comparative advantage for green hydrogen growth. With the correct infrastructural development, the region has the potential to become a leader in the emerging hydrogen economy. In particular, when considering regions such as Europe and Far-East Asian countries like South Korea and Japan, who face limited renewable energy potential and are expected to rely on imports for their future hydrogen supply, the GCC's central geographic position between these two regions can provide efficient, central trade flows, placing the region in a highly advantageous position to capture substantial future export markets [10]. Aside from natural comparative advantages, the region's potential is further being accelerated by ambitious national targets to propel decarbonisation and low-carbon supply chains. According to Khan and Al-Ghamdi [11], UAE and Oman are aiming for total net-zero by 2050, Saudi Arabia and Bahrain are aiming for total net-zero by 2060, Qatar is aiming for a 25% reduction in emissions by 2035 and Kuwait is aiming for a 7.4% reduction in emissions by 2035. These targets- along with higher funding availability in the region- are contributing to the GCC's hydrogen growth. One thing to note is that, regionally, hydrogen investments are being steered by the national sovereign wealth funds, such as the Saudi Public Investment Fund (PIF). The PIF has allocated an investment of $10 billion towards green hydrogen development [12], while, as another example, Kuwait has allocated $ 6.3 billion towards clean energy projects since 2022 [13]. One thing that is advantageous in this regard is that in the GCC, the allocation of national funds is guided by the primary policymakers in the country, so, when targets such as hydrogen development are classed as a critical national target, the amount of financial investment going into the deployment of hydrogen is enough to rapidly accelerate development. Because there is a national alignment between the amount of investment that's going into hydrogen projects, and the associated policies or strategies, this is leading to a more rapid regional advancement of hydrogen in the region. Despite this potential however, the optimal design of a long-term sustainable supply chain network that (1.) includes production sites, storage facilities, and transportation options and (2). balances all real-life aspects, such as cost, environmental, and safety/risk objectives still presents a universal challenge, and requires careful planning and modelling that can capture changes in the performance of the supply chain in each of these objectives over time. The current literature on hydrogen supply chain design is discussed in greater detail in Chapter 2 (literature review), however, several works have assessed hydrogen supply chains. For example, Dagdougui [14] conducted a review for design systems for hydrogen supply chains. In this work, it was found that the majority of the existing literature utilises mathematical optimisation methods for the design of HSCs. However, most of the work only used single-objective optimisation focusing on the minimisation of either cost or emissions, with fewer works addressing the safety/risk aspect. Similar observations were made in Ref. [15], where hydrogen supply chain optimisation mainly focused on minimising cost, with some consideration of environmental objectives, and less focus on safety/risk. It is important to note that each objective function is critical for the design of a HSC. However, focusing solely on optimising one is highly likely to renounce the performance of the others. For example, focusing solely on cost optimisation is likely to result in a supply chain that is more environmentally degrading or less safe, and vice versa [15]. This is also true for each individual echelon of the supply chain. For hydrogen production for example, 'grey' hydrogen, which describes hydrogen produced via the process of steam methane reforming (SMR) using fossil fuels such as natural gas, still remains the most globally abundant. SMR releases between 8-12 kg CO_2 per kg H_2 produced, but is still a highly favoured process due to its high efficiency of 74 % and low hydrogen cost of ~ $2/kg-$H_2$ [16]. Electrolysis on the other hand currently costs about $10/kg-$H_2$, but can have a carbon footprint as low as 0.6 kgCO_2e when powered by renewable grids [16]. Because of these apparent trade-offs between the various objectives, this work aims to evaluate and minimise the trade-offs between the cost, environmental and safety/risk objectives via the use of multi-objective optimisation and multiple-criteria decision making (MCDM) tools, discussed in greater detail in Chapter 2.

1.2 Research Problem and Objectives

Furthering the choice to focus this research on the GCC, even before infrastructural development (i.e. production and storage plants and transportation modes), for a HSC network to be fully optimised, it is critical to consider the natural comparative advantages that can facilitate green hydrogen development commercially. As previously mentioned, the GCC's annual solar radiation lies between 2,200-2,500 kWh/m^2 [8], sitting at higher end of global ranges of 640-2400 kWh/m^2 [10]. Because of this natural advantage, solar photovoltaic (PV) installation costs have dropped significantly regionally. In Kuwait, for example, solar PV installation costs dropped from \$4,731/ KW to \$883/ KW (~81% reduction) [17], while in Saudi Arabia, a new world record was reached for the lowest levelized cost of electricity (LCOE) for solar PVs, reaching \$10.4/ MWh [18]. Here, the region's higher solar radiation acts similarly to economies of scale. Because of high-intensity solar resources, more electricity is produced per unit of installed capacity, which decreases the cost per kilowatt-hour (\$/kWh). As such, the GCC experiences higher capacity factors, meaning the same, or even smaller, PV systems produce more energy over their lifetime, thus reducing LCOE. Overall, a HSC that harnesses a country's already existing natural comparative advantages (in this case the GCC's solar abundance), is likely to be more sustainable due to the energy source always being available to drive down costs, which in turn makes regional investment into the rest of the HSC network more commercially attractive to stakeholders.

To clarify the energy source underpinning this research: all hydrogen production modelled in this thesis is driven exclusively by solar photovoltaic (PV) electricity. Solar PV was selected as the sole energy source because it represents the most technically mature and economically competitive renewable technology available at scale in the GCC, given the region's exceptional irradiance levels and rapidly declining installed costs. By fixing the energy source as solar PV, the optimisation problem becomes focused on the technical supply chain infrastructure-electrolyser selection, storage configuration, and transportation mode-rather than on energy source comparison. This allows for a more rigorous and directly comparable evaluation of supply chain alternatives. Regarding the current energy landscape in the GCC: despite ambitious renewable energy targets, the region remains predominantly fossil-fuel dependent, with oil and natural gas accounting for almost all final energy consumption including electricity generation [4]. The share of renewables in total GCC electricity generation capacity stood at approximately 3% in 2022 [4], and while renewable capacity is growing rapidly, it remains well below the levels required to fully support large-scale hydrogen production from grid electricity [19]. This context is important because it underscores both the scale of the transition required and the strategic importance of anchoring future hydrogen production to dedicated renewable capacity rather than grid electricity, which currently carries a significant carbon intensity.

As far as designing the supply chain network, the objective of this research is to design a three-stage green hydrogen supply chain network (production, storage and transportation) using multi-objective optimisation and multiple-criteria decision making (MCDM) tools to simultaneously minimise three objective functions: cost ($), environmental (carbon footprint), and safety/risk (index). More specifically, this research aims to answer the overarching question of: when considering a tri-objective optimisation problem, what is the most optimal electrolyser, what is the optimal storage method, and what is the optimal transportation mode for the GCC, and does this change across times and evolving demands? Two regional case studies are considered: Kuwait and Saudi Arabia. The choice of these two countries as case studies was for the following reasons. First, both Kuwait and Northwestern Saudi Arabia have direct access to the Strait of Hormuz- one of the world's most critical export passages where between 20-30% of total global oil trade currently occurs [20]. For future hydrogen exports, hydrogen export to the aforementioned import-dependent markets (Europe and Far-East Asia) could occur via the same route. Second, for Saudi Arabia specifically, evaluating a HSC network is critical due to the Northwestern region of Saudi Arabia being the location of the famous NEOM Green Hydrogen Project, which aims to become the world's largest commercial green hydrogen facility [21]. Another reason for Saudi Arabia is that the Northwestern region is located directly along the Red Sea coastline, where currently ~14% of global maritime trade and 30% of global containerised trade transit annually via the Suez Canal [22]. Saudi Arabia is the only GCC country with Red Sea export access and so, could benefit from additional facilitated hydrogen exports via these well-established export corridors in future hydrogen economies. The Kuwait case study focuses on a single period (2050) to determine what the optimal HSC configuration looks like in a static, one-period snapshot, focusing instead on altering demands' impact on the supply chain performance, while the Saudi Arabia case study focuses on a multi-period model (2025-2060) to determine how the optimal HSC configuration evolves across multiple planning periods, as well as how different demand scenarios (low, medium, high) affect the optimal configuration over time. For both case studies, the demands for low, medium and high scenarios are based on the existing and projected penetration rates of hydrogen fuel cell vehicles (HFCVs) in the transport sector in the assessed years (discussed in greater detail in Chapter 4). In general, demand is found to have an immense impact on HSC performance. In a study by Dayhim et al. [23] for example, demand uncertainty was found to be the most critical factor influencing the number, location, and capacity of hydrogen production and storage plants, while increased demand significantly decreased cost per kg/H_2 from \$13.52/kg to \$6.84/kg (49.4% decrease) due to economies of scale. Other studies [24,25] also concluded that demand variations exerted a very strong impact on the overall HSC system. In Ochoa et al. [25], it was found that developing a HSC optimisation approach that considers demand variability can reduce infrastructure investment costs by up to 26%, again highlighting the importance of demand incorporation in HSC design planning.

For the supply chain echelons, the same production (electrolysers), storage, and transportation methods are compared across economic, environmental and safety/risk objectives for the Kuwait and Saudi Arabia case studies. This is discussed in greater detail in subsequent chapters, but, in general, one of the aims of this research is to compare the ‘technical’ side (i.e. the actual infrastructure), rather than also including differing energy sources. Because solar energy is adopted as the sole energy source, the multi-objective optimisation problem becomes a technical one, rather than one that becomes energy-source- focused. Another important consideration of this research is stakeholder preference integration. In both the Kuwait and the Saudi Arabia case studies, stakeholder preferences regarding which criteria should be ranked most to least important across economic, environmental and safety/risk objectives are integrated into the optimisation problem via a novel hybridisation of two multiple criteria decision making (MCDM) analysis methods: the analytic hierarchy process (AHP) and the Technique for Order of Preference by Similarity to Ideal Solution (TOPSIS). Beyond technical optimisation, the realisation of a hydrogen supply chain relies also on stakeholder preferences, as stakeholders will ultimately be the ones driving the real-world establishment of HSCs.

The objectives and novelty of this research can be summarised as follows: two fully green, solar energy sourced hydrogen supply chains are designed and analysed, one in Kuwait (full country) and one in Saudi Arabia- specifically the Northwestern region. The Kuwait case study focuses on a single long-term period (2050), focusing on two ‘no priority’ (i.e. no stakeholder-influenced criteria rankings, each criterion is equal) optimisation problems and one AHP-TOPSIS hybridised optimisation problem. Low, medium and high demand scenarios are assessed in each of these optimisation problems. Here, the first objective is to determine which electrolyser, storage method and production mode are the most optimal across multi-objective problems, and the second objective is to determine if the optimal HSC configuration changes when explicit stakeholder preferences are considered in the AHP-TOPSIS approach. Next, the Saudi Arabia case study focuses on a multi-period model (2025-2060) using a novel, mathematical optimisation framework that captures evolving stakeholder preferences through time-dependent re-weightings of economic, environmental, and safety criteria. Because, in the Kuwait case study, the AHP rankings are static due to a single-period focus, the Saudi Arabia case study incorporates dynamic re-evaluations via the novel optimisation framework presented in the Methodology to reflect evolving stakeholder priorities and capture their effect on the HSC over time. The multi-period case study serves to incorporate a broader range of demand variability and capture the transitional dynamics between the short and long term and determine if a HSC system can achieve optimal performance when operating at intermediate maturity levels. Finally, a further motivation for choosing Kuwait and Saudi Arabia as case studies is their geographic proximity to each other. As Kuwait and Northwestern Saudi Arabia share a border and face similar climatic conditions, this research also investigates whether a trans-regional HSC configuration or at least similar HSC configurations could be adopted across the GCC.

1.3 Thesis Structure Overview

The remainder of this thesis is structured as follows. Chapter 2 presents a systematic review of the existing literature on green hydrogen supply chain design, multi-criteria decision-making frameworks, and GCC energy transition policy, identifying the critical gaps that motivate the methodological approach adopted in this work. Chapter 3 develops the research methodology, detailing the mathematical formulation of the multi-period MILP optimisation model, the integration of AHP–TOPSIS multi-criteria decision-making, and the novel contributions of the dynamic, demand-responsive framework relative to existing approaches in the field. Chapter 4 presents the two regional case studies- Kuwait under a single-period static framework and

Saudi Arabia's Northwestern region under a multi-period dynamic framework spanning 2025 to 2060- reporting the optimisation results across hydrogen production, storage, and transportation stages under low, medium, and high demand scenarios. Chapter 5 synthesises and compares the results of both case studies, develops the cross-country comparative analysis, and translates the quantitative findings into a scientifically grounded framework for trans-regional GCC hydrogen infrastructure design, including practical considerations for real-world implementation. Chapter 6 presents the conclusions of the thesis, consolidates the principal contributions to knowledge, and sets out a prioritised agenda for future research.

2. Literature Review

2.1 Hydrogen as an Energy Vector and an Enabler for Decarbonisation

Hydrogen can be generated from both renewable and non-renewable energy sources [26]. Because of this, the discussion around hydrogen as an energy vector has been very promising in the literature. Another advantage is that, at standard temperature and pressure (STP), hydrogen has a low density of about 0.09 g/L [27]. Compared to gasoline, which has a density of 710-770 g/L [28], hydrogen's much lower density shows vast potential for hydrogen as a fuel, as less space would be required to store or transport the same volume. Hydrogen is also the most abundant gaseous element in the world, accounting for more than 90% of the world's total [27]. Other noteworthy advantages include hydrogen's high energy density (120 MJ/kg) [29], which is almost triple that of conventional fossil fuels like gasoline (44 MJ/kg) [29], and its versatility: hydrogen can be stored as a fuel for use in various energy sectors to produce heat, power and electricity.

Notwithstanding these advantages, hydrogen as an energy carrier also presents a number of significant challenges that must be considered in any balanced assessment. From a physical standpoint, hydrogen's very low volumetric energy density at ambient conditions means that substantial compression or liquefaction is required before it can be stored or transported efficiently- both of which are energy-intensive processes that reduce overall system efficiency. Hydrogen compression alone can consume more than 25% of the hydrogen energy content [30]. The conversion of renewable electricity to hydrogen and back to usable energy (power-to-hydrogen-to-power) results in round-trip efficiencies typically in the range of 28–52%, with an average of approximately 40% [31], significantly lower than battery storage alternatives for short-duration applications. From a safety perspective, hydrogen's wide flammability range (4–

75% by volume in air) and very low minimum ignition energy of approximately 0.017 mJ make it inherently more hazardous than conventional fuels, necessitating stringent material standards, leak detection systems, and ventilation requirements [32]. Economically, the current levelized cost of green hydrogen produced from solar PV was estimated at approximately \$3.5–\$5/kg in 2023 [33], substantially higher than grey hydrogen at approximately \$1–\$2/kg [33], and achieving cost parity with fossil fuel alternatives requires continued reductions in electrolyser capital costs and renewable electricity prices [30]. Furthermore, the lack of established hydrogen refuelling infrastructure and the significant capital requirements for dedicated pipeline networks represent major barriers to large-scale deployment. These challenges are not insurmountable, but they emphasise the importance of rigorous supply chain optimisation, which is precisely the focus of this research; to identify the configurations that best balance economic, environmental, and safety trade-offs.

Globally, the current demand for hydrogen stands at about 100 million tonnes per annum (MTPA) [16]. In a net-zero scenario, this demand would need to reach between 530- 810 MTPA to accommodate global needs [16]. Between 20–40 % of this hydrogen is expected to be blue, while the remaining 60–80% will come from green energy sources [16]. As previously mentioned, ‘grey’ hydrogen, which describes hydrogen produced via SMR using fossil sources like natural gas is currently the world’s most abundant due to its high efficiency and low cost, but this method contributes largely to increased carbon footprint. ‘Blue’ hydrogen on the other hand also describes hydrogen produced via SMR utilising natural gas. However, this method integrates Carbon Capture, Utilisation and Storage (CCUS) technologies within the SMR process. CCUS facilitates the capture and sequestration of CO_2 emissions generated during hydrogen production, mitigating some of the carbon footprint associated with grey hydrogen. As such, hydrogen produced via CCUS integration has a lower carbon footprint of 4-5 $kgCO_2e$ [34]. As for green hydrogen, because it is produced entirely via renewable sources, it can achieve the lowest carbon footprint of 0.6 $kgCO_2e$ [16]. It is important to note, that although this work focuses on green hydrogen supply chain optimisation, the GCC region also holds immense advantages for blue hydrogen production. GCC countries hold over 40 trillion cubic meters (TCM) of proven natural gas reserves, representing about 20–26% of the global total and catering to ~11% of global annual demand [35]. As far as CCUS developments, the region currently captures approximately 3.7 MTPA of CO_2, accounting for between 8% to 10% of global operational CO_2 capture capacity [36]. However, this research chooses to focus on green hydrogen supply chain optimisation for several reasons. First, although transportation is a challenge that for now affects all types of hydrogen (i.e. green, blue, and grey), the existing pipelines that transport natural gas are not yet a developed option for hydrogen transportation. Hydrogen takes about four times more energy to move through an existing natural gas pipeline than natural gas does [16]. Furthermore, although natural gas pipelines to carry a blend of natural gas and hydrogen (approx. 15% hydrogen) is possible given slight pipeline modifications, converting existing natural gas pipelines to deliver pure hydrogen would require substantial modifications and costs. As such, the development of dedicated hydrogen pipeline infrastructure, despite a higher capital cost of >$2 billion [37], may present a more technically viable long-term solution than relying on retrofitted natural gas networks. Moreover, given the strategic importance of natural gas to the GCC economies, repurposing existing gas infrastructure for hydrogen would risk disrupting established export and domestic supply systems, and would be less practical than developing pipeline infrastructure specifically designed for hydrogen transport.

Another important consideration as to why green hydrogen presents a more long-term viable solution for the GCC is the region's highly established petrochemical sector and the decarbonisation potential within. As previously mentioned, the current global hydrogen demand stands at about 100 MTPA. Most of this consumption stems from: the refining sector-accounting for about 45% of global hydrogen use; ammonia production for fertilisers at ~38%, and methanol production at between 12–13% [16]. In these applications, hydrogen functions primarily as an industrial feedstock rather than as an energy carrier.

The GCC represents a significant share of global petrochemical exports, supported by their aforementioned natural gas reserves and mature gas-processing infrastructure [38]. Within these sectors regionally, there are already active CCUS initiatives embedded into production systems. For example, in Jubail, Saudi Arabia, the Uthmaniyah CCUS facility captures 800,000 tonnes of CO_2 annually from the production of ethylene glycol and reutilises the captured carbon in the production of urea, methanol, and liquefied CO_2 for commercial applications [39]. Given that hydrogen for ammonia and methanol production is already structurally integrated within gas-based industrial value chains, a 'blue' hydrogen pathway combined with CCUS may provide a relatively direct route for reducing emissions within these existing sectors. However, the deployment of hydrogen as a transport fuel represents a structurally different application, requiring new infrastructure, distribution systems, and supply chain configurations. In this context, the development of green hydrogen supply chains offers a longer-term strategy aligned with the decarbonisation of the transport sector and broader energy system diversification, rather than solely the decarbonisation of existing petrochemical feedstock demand.

Lastly, in the context of global decarbonisation objectives and in accordance with the commitments set forth in the Paris Agreement, the scaling-up of green hydrogen is identified as a key pathway for limiting global temperature rise to below 1.5°C [40]. Accordingly, this study focuses on green hydrogen development in alignment with international climate commitments, particularly for application in hard to-abate sectors such as transportation.

2.2 Hydrogen Supply Chains in the GCC Context

As mentioned in Chapter 1.1, from a comparative advantages perspective, the GCC is an ideal contender for the development of green hydrogen supply chains. Abundant solar resources, subsequent competitive solar PV costs, ambitious net-zero targets, and alignment between national targets and allocated investments are all contributing to the region's rapid growth in green hydrogen development. Furthering to the point mentioned in Chapter 1.1 about the advantage of alignment between the allocation of funds to projects being guided by the primary policymakers in the countries (i.e. the sovereign wealth funds), there is a critical foundational importance here as to how this maximises HSC development and puts the GCC region in an even more favourable position. When capital allocation is aligned with long-term green hydrogen strategies, investment can be directed towards the most system-critical nodes of the supply chain- namely renewable generation, large-scale electrolysis, dedicated hydrogen pipelines, and geological storage (e.g. salt caverns) [41]. This prevents partial or fragmented infrastructure development (e.g. isolated production without storage, or storage without transport connectivity), which would otherwise constrain system throughput [42]. More specifically, this can enable: the co-location of solar PV and electrolysers to minimise transmission losses; early development of backbone infrastructure (i.e. pipelines) to unlock potential economies of scale; the deployment of high-CAPEX technologies when long-term demand is projected; integrated planning across production–storage–transport rather than siloed investment, and the reduction of underutilisation risk for capital-intensive assets. In turn, this can maximise clean energy output because green hydrogen production is infrastructure-dependent: electrolysers require renewable electricity; storage must absorb intermittency; transport must enable continuous flow to demand centres or export terminals [42]. If any link is underdeveloped, system capacity is bottlenecked. As such, this strategic alignment between the GCC's resource endowment, institutional investment structures, and long-term hydrogen policy frameworks establishes structurally favourable conditions for the large-scale deployment of integrated green HSCs. Tables 1 and 2 present the hydrogen-related policies, investment frameworks, and strategic initiatives currently adopted and under development in the GCC countries.

Table 1: GCC clean energy investments

GCC Country	**Clean Energy Investment**	[16]
Saudi Arabia	$186.5 billion planned in renewable energy (production and distribution) projects by 2030	
United Arab Emirates	$63 billion investment towards clean and renewable energy sources by 2050	
Qatar	$1 billion ammonia-to-hydrogen plant announced in 2022	
Oman	$20 billion worth of hydrogen agreements signed in 2023	
Kuwait	$6.3 billion worth of ongoing clean energy projects underway in 2022	
Bahrain	In 2023, signed deals to construct a 72-MW solar park including rooftop and ground-mounted solar systems and EV charging stations	

Table 2: GCC clean energy policies and strategies

GCC Country	**Clean Energy Policies and Strategies**	
Saudi Arabia	Plans to generate 50% of electricity from renewables and 50% from gas by 2030. Major projects include the Sudair solar PV plant (1500 MW capacity, powering ~185,000 homes and offsetting ~2.9 Mt CO_2 annually) and the NEOM green hydrogen facility (expected operation in 2026, producing 660 tonnes/day of green hydrogen, equivalent to current global annual production).	

United Arab Emirates	National green hydrogen strategy targeting 1.4 million tonnes per annum of low-emission hydrogen by 2031 (71.4% green hydrogen). By 2050, production is expected to scale to 15 million tonnes per annum. Strategy includes hydrogen infrastructure expansion through two hydrogen hubs and a hydrogen R&D centre, with plans to establish a global innovation centre by 2050.	[16]
Qatar	Qatar National Vision targets 20% of electricity from renewable energy by 2030, supported by solar PV projects with approximately 800 MW capacity.	
Oman	Aims to derive at least 30% of electricity from renewables by 2030. Key initiatives include wind farms in Dhofar, solar independent power projects in Manah, hybrid solar-diesel facilities, and the ‘Sahim’ rooftop solar programme.	
Kuwait	Targets 15% of power supply (~4.5 GW) from renewables by 2030. Aims to reduce carbon emissions by 7.4% by 2035 (business-as-usual scenario) through renewable expansion, improved efficiency, fuel switching to natural gas, and CCUS deployment.	
Bahrain	Targets 6% energy efficiency and 5% renewable energy by 2025, increasing to 10% by 2035. Initiatives include solar power from landfill sites, rooftop solar on public buildings, and exploration of floating solar technologies due to land constraints.	

2.3 Hydrogen Supply Chain Components and their status in the GCC

Although the GCC's structural advantages position it favourably for green hydrogen development; to compete effectively with established fossil fuel systems, HSC design must strategically integrate economic efficiency, environmental performance, and risk and safety considerations within a unified optimisation framework to ensure long-term resilience and avoid sub-optimal trade-offs that could undermine the long-term credibility and scalability of hydrogen in the transport sector. This is discussed in greater detail in Chapter 2.4. Furthermore, the development of a fully integrated hydrogen supply chain (HSC) linking production, storage, and transport infrastructure continues to present significant technical and economic challenges. In this context, it is essential to investigate the individual production, storage, and transportation technologies in terms of their technological maturity, infrastructure readiness, and current deployment status within the GCC, in order to assess their practical feasibility for large-scale integration.

2.3.1 Electrolysers

As previously mentioned, electrolysis is the main method used for green hydrogen production. In the electrolysis process, pure hydrogen is produced at the cathode and is separated from water and oxygen produced at the anode via a membrane (i.e. electrolyser type) [43]. Because this process utilises electricity sourced from renewable energy, it results in zero-emissions, making it highly environmentally favourable [43]. In this work, three types of electrolysers are assessed: proton exchange membrane (PEM); alkaline water and anion exchange membrane (AEM). These methods differ based on the electrolyte and ionic agents used, as well as the operating conditions.

The selection of these three electrolyser technologies is justified on the basis of their current or near-term commercial relevance, technological maturity, and complementary performance characteristics. Alkaline water electrolysis represents the most industrially mature and widely deployed technology for large-scale hydrogen production, making it an essential baseline for comparison. PEM electrolysis is the most prominent emerging commercial alternative, distinguished by its high efficiency, rapid dynamic response, and compatibility with intermittent renewable energy sources such as solar PV- properties that are particularly relevant to the GCC context. AEM electrolysis was selected as the third option because it occupies a strategically important developmental niche: combining the cost advantages of alkaline systems (non-precious metal catalysts) with the membrane architecture of PEM, it represents the most likely next-generation commercial electrolyser technology. Other electrolyser types, such as solid oxide electrolysis (SOEC), were excluded because they operate at very high temperatures (700–850°C) and remain at a pre-commercial stage of development, making their inclusion in a near-to-mid-term supply chain optimisation framework premature. The three technologies selected therefore collectively span the full spectrum of commercially relevant options for large-scale green hydrogen production in the 2025–2060 planning horizon considered in this study.

Proton exchange membrane (PEM) electrolysers are well-established electrolysers commercially. In PEM configurations, a solid sulfonated polymer membrane functions as the electrolyte, facilitating proton conduction between electrodes. PEM electrolysers are advantageous as they typically operate at relatively low temperatures, ranging from between 30 to 80 °C, and at high current densities in the order of 1–2 A/cm^2 [44]. This allows for the production of hydrogen with purity levels reaching 99.99% [44]. This technology is often regarded as comparatively safe due to its solid-state design and absence of corrosive liquid electrolytes. Additionally, the use of platinum-group metal catalysts, combined with operation in a low-pH environment, enhances electrochemical reaction kinetics and contributes to rapid hydrogen generation. However, due to the use of rare, precious metal catalysts (i.e. platinum), PEM electrolysers are currently the most expensive, ranging on average between \$1,000 to \$2,500 per kilowatt (kW) for fully installed, industrial-scale systems [45].

Alkaline water electrolysers on the other hand are the most mature and widely deployed technology for industrial-scale green hydrogen production, reaching a current global installed capacity of 1.4 gigawatts (GW) at the end of 2023, nearly doubling from 2022 [46]. These electrolysers are highly favoured due to their costs ranging between \$500 to \$1000 per kW, which is competitive with SMR [47]. However, the major challenge associated with alkaline water electrolysers is that they operate at limited densities (0.2–0.8 A/cm^2) [48] and utilise corrosive KOH electrolytes that react with external CO_2, which produces lower purity hydrogen ~99.5% [49]. However, further purification processes, such as pressure swing adsorption (PSA) or catalytic recombination to remove oxygen and moisture can increase the purity to >99.9% [50].

Anion exchange membrane (AEM) electrolysers work in a similar manner to alkaline water electrolysers. Here, water is split into hydrogen and oxygen by conducting hydroxide ions (OH^-) from the cathode to the anode [51]. This is advantageous because it prevents gas crossover and replaces the need for highly corrosive liquid electrolytes [51]. Furthermore, AEM presents a major cost advantage by enabling the use of non-precious metal catalysts, such as such as nickel or iron-based compounds, which lowers material costs relative to platinum-dependent PEM systems. AEM is considered a “hybrid” technology between alkaline water and PEM. This is because these systems combine the low-cost catalyst advantage of alkaline systems with the membrane architecture of PEM systems [52]. Although advantageous, AEM is still at a lower technological maturity level compared to alkaline and PEM, primarily due to the low stability of hydroxide-conducting polymers and long-term degradation issues [16]. Nonetheless, current developments in AEM are allowing for the mitigation of this issue through developing membranes with a greater resistance to hydroxide attacks, or using protective additives, such as cerium oxide (CeO_2) nanoparticles, which act as radical scavengers to reduce polymer degradation [53].

As far as GCC considerations, alkaline water electrolysers are currently the most used and dominant type of electrolyser, particularly for large-scale, industrial green hydrogen projects. This is due to their lower capital costs and established maturity [54]. However, PEM electrolysers are also gaining wide investment in the region, with Saudi Arabia alone’s PEM market size projected to grow from $ 368.7 million in 2025 to $ 1.47 billion by 2031, exhibiting a projected compound annual growth rate (CAGR) of 25.9% during the forecast period [55]. This increased traction is due to PEM’s ability to better manage the intermittency of renewable energy and faster response times (<1 s to <5 s) [56]. While alkaline water and PEM electrolysers currently dominate the GCC market, AEM is also gaining traction due to its lower cost, reduced reliance on critical raw materials, and high efficiency [56]. This is because with the correct development, AEM combines the cost advantages of alkaline systems with the operational flexibility of PEM electrolysers. Given the region’s reliance on solar-driven sourcing, which results in daily intermittency, technologies capable of dynamic load-following while maintaining lower material costs are strategically relevant. As AEM systems continue to mature, they will be able to offer a cost-effective and flexible alternative suitable for large-scale renewable-integrated hydrogen production in the GCC.

2.3.2 Storage Methods

For storage, compressed gas tanks, salt caverns and compressed gas trucks are the methods compared in this work. Compressed gas tanks are currently the most globally established hydrogen storage technology. This process involves the physical storage of compressed hydrogen gas in high-pressure vessels. Hydrogen is typically produced at relatively low pressures (20–30 bar) [57] and has a low density of <0.1 g/L [58]. Consequently, it must be compressed prior to being stored. The most economically feasible method of densifying the hydrogen is by compressing it at high pressure (between 180 and 900 bar) for storage in a tank [59]. Following compression, the hydrogen can be stored and eventually transported. However, in its gaseous state, hydrogen is stored at high pressures (350-700 bar), resulting in a higher risk of explosion in the event of road accidents or fires, thus compromising the safety aspect [29].

The selection of these three storage technologies is justified as follows. Compressed gas tanks represent the most globally mature and commercially widespread hydrogen storage method, providing a necessary benchmark against which alternative options can be evaluated. Cryogenic tanks were selected because they represent the dominant large-scale storage method for liquid hydrogen in industrial and aerospace applications, offering significantly higher volumetric energy density than compressed gas- a characteristic of relevance to large-scale, export-oriented supply chains such as those envisioned for the GCC. Salt cavern storage (geological storage) was selected as the third option because it is increasingly recognised in the literature as the most cost-effective and scalable long-duration hydrogen storage technology, particularly well-suited to the flat desert terrain and subsurface geology of the GCC. Other storage technologies, such as metal hydride storage, were not included in this study as they remain at a lower technological readiness level for bulk, stationary storage applications and are not yet cost-competitive at the scales considered here.

It is important to clarify the terminology used in this thesis with respect to geological hydrogen storage. “Geological storage” is a broader term encompassing all subsurface storage options, including salt caverns, depleted oil and gas reservoirs, and deep saline aquifers. Salt caverns represent one specific type of geological storage, characterised by their excavation within halite (rock salt) formations through controlled dissolution. In Kuwait, the geological storage option modelled in this study is based on salt cavern formation within depleted oil reservoirs- consistent with the region’s geological conditions. In the Saudi Arabia case study, where recognised salt cavern formations are not present within the study boundary (the Northwestern region), the Saq Aquifer is used as an alternative geological storage medium, representing porous-media underground storage. Throughout this thesis, “salt cavern storage” and “geological storage” are used with the following convention: “salt cavern storage” refers specifically to the Kuwait case study where depleted reservoir-based salt cavern formation is modelled, while “geological storage” is used in comparative contexts to refer to the broader category of underground hydrogen storage that includes both salt cavern and aquifer-based options. This distinction is maintained consistently throughout the thesis. Notwithstanding this terminological distinction, the Saq Aquifer is functionally modelled as an analogue to salt cavern storage in the Saudi Arabia case study, given that both serve the same system-level role of large-scale, long-duration underground hydrogen buffering, and are evaluated against the same storage criteria within the tri-objective optimisation framework; the label 'geological storage' is therefore used for Saudi Arabia to preserve terminological accuracy while maintaining full comparability of results across both case studies.

Salt caverns present a low-risk, high volume storage option that is gaining significant traction globally, due to its affordability, safety, and storage capacity [60]. Salt caverns are formed out of existing salt bed deposits that can subsequently be used as storage vessels [16]. The cavern is made by drilling a well down into the formation, where water is then pumped through the well to dissolve the salt [16]. For hydrogen storage, aside from the aforementioned advantages, this also presents further benefits, including prevention against reservoir degradation, as the salt formations exhibit low permeability and creep behaviour that naturally seals microfractures and restricts hydrogen migration [60]. In turn, this increases the longevity of the salt cavern as a storage system. Salt caverns are also open vessels, meaning they offer very high deliverability and flow rates [61]. For the GCC, salt caverns are also particularly advantageous as they work optimally on flat desert land and can also be made in depleted oil and gas reservoirs [62].

Cryogenic tanks are another well-established technology for hydrogen storage- particularly in the aerospace industry [63]. In this method, hydrogen is liquefied at low temperatures (~253°C) and is subsequently stored at the same temperature. Cryogenic tanks provide a better energy density compared to compressed gas, due to the significantly higher volumetric density achieved (~100% vs compressed gas' ~20%) [64]. However, although mature and widely used, this method presents several critical challenges when considering multi-objective goals. First, cryogenic storage is highly energy-intensive (~10 kWh/kg) [65] and the liquefaction process is highly capital-intensive. Typically, the liquefaction process accounts for between 40–50% of the total capital expenditure (CAPEX) of the cryogenic storage system [65]. Another challenge is boil-off loss. Because cryogenic hydrogen is stored at extremely low temperatures, it absorbs heat from the warmer ambient environment [65]. In turn, this also impacts the safety aspect. Because of boil-off, liquid hydrogen evaporates almost immediately upon release due to the rapid increase in temperature above its storage temperature. This increases the risk of ignited releases, which in turn can result in flash fires, pool fires, and deflagrations [66]. Nonetheless, the potential risk of flammable mixture formation in the event of a hydrogen leak can be mitigated with adequate ventilation [66].

In the GCC, compressed gas tanks are presently the most utilised hydrogen storage method. Regional investments in these tanks are projected to grow from $ 9.6 billion in 2025 to $ 15.8 billion by 2032 (7.4% CAGR) [67]. In particular, the region is heavily investing Type 4 carbon fibre cylinders, due to their capabilities of increasing safety in compressed gas storage, higher pressure capabilities (700–950 bar), and lower weight compared to traditional metal tanks [67]. As for salt caverns, the GCC presently has no recognised salt caverns. However, depleted oil reservoirs can be converted into salt caverns for hydrogen storage. For the Organisation of the Petroleum Exporting Countries (OPEC), which includes all countries of the GCC, the oil field depletion rate is ~5 % [68]. As such, about 5% of national oil fields for each GCC country can be converted for hydrogen storage. As for cryogenic tanks, this storage method is currently in a transition phase in the GCC with respect to hydrogen. While cryogenic tanks are already highly utilised in the region for their industrial liquefied natural gas (LNG) logistics, the major adoption of cryogenic tanks for hydrogen is expected to develop with the completion of regional green hydrogen projects [69].

2.3.3 Transportation Modes

For transportation, compressed gas trucks, pipelines and cryogenic trucks are the transport modes assessed in this work. For small-scale or localised hydrogen transport, compressed gas trucks (tube trailers) are the most commonly used methods globally [70]. These trucks carry hydrogen in high-pressure cylinders (ranging from 200 to 500 bar) [70]. Following compression at pressures of >180 bar, the high-pressure cylinders then are stacked onto a trailer, which is subsequently pulled by the truck. This method can store up to 25,000 litres of hydrogen compressed to 200 bar, which is a significantly advantageous capacity [71]. On average, a fuel cell electric vehicle (FCEV) requires about 5 kg of hydrogen for every 300 miles of transport [72]. As such, a 25,000-litre capacity compressed at 200 bar yields about 25,200 miles of transport [72]. However, the issue with compressed gas trucks lies in their comparative transport capacity compared to existing gasoline trucks. On average, the capacity per compressed gas truck is 600 kg/day [72]. Conversely, gasoline trucks can carry more than 70 times this parameter, where daily capacity can be as high as ~44,000 kg [73]. Consequently, this raises cost concerns with respect to the quantity of trucks required to be able to compete with existing gasoline transport capacity and requires significant R&D efforts to develop.

The selection of these three transportation technologies is grounded in their relevance to both current and projected hydrogen supply chain configurations at the scales considered in this study. Compressed gas trucks are selected because they represent the dominant near-term transport solution for hydrogen distribution at short-to-medium distances and low volumes, making them an essential reference case for early-stage supply chain deployment. Pipelines are included because they are the established mode for large-scale, continuous hydrogen transport in mature systems and are widely regarded as the lowest-cost option per kilogram at high volumes and long distances- characteristics directly relevant to the trans-regional GCC context. Cryogenic trucks are selected because they offer substantially higher payload capacity than compressed gas trucks and are increasingly relevant for intercity and interregional hydrogen transport where pipeline infrastructure is not yet established. Other transportation technologies, such as liquid organic hydrogen carriers (LOHCs) and ammonia-based transport, were not included in this study because they require additional conversion and reconversion steps that introduce energy penalties and complexity beyond the scope of the current tri-objective framework. The three selected modes therefore collectively cover the principal commercially viable options for hydrogen transport across the demand scales and distances relevant to the Kuwait and Saudi Arabia case studies.

Based on current industry practices and infrastructure, pipelines are the most globally widespread method for hydrogen transportation for large-scale, consistent, transport [74]. Pipelines present the most-cost effective transport method for moving large volumes of hydrogen, especially for supplying industrial hubs like chemical factories and refineries [75]. For large-scale transport (>200,000 tonnes per year), pipelines provide the lowest levelized cost of hydrogen (LCOH) compared to compressed gas trucks or cryogenic trucks, on average falling below \$3/kgH_2 for distances up to 7,000 km [76]. Although an extremely advantageous transport method, the main limitation for pipeline transport lies in the capital cost. As previously mentioned in Chapter 2.1, retrofitting existing natural gas pipelines is not a reasonable option, due to ineffective energy requirements and modification costs, which would also compromise the existing LNG network. As such, for hydrogen transport, the construction of a new pipeline network would be required. Hydrogen pipelines cost approximately 68% more than natural gas pipelines [77]. This includes not only the cost of the materials for the pipelines themselves, but also costs related to installation and rights of way (ROW), fusion and leak testing [78]. Despite the high capital investment however, pipelines present a safe and effective hydrogen transport method.

While compressed gas trucks are more common for transporting hydrogen at short distances, cryogenic trucks are emerging as a potential hydrogen transport technology for longer distances. This is because they present various advantageous characteristics over compressed gas trucks. First, the transport capacity of a cryogenic truck is roughly 4-5 times higher than that of compressed gas trucks. A standard cryogenic hydrogen truck can transport approximately 4,000–5,000 kg of hydrogen, whereas a conventional tube trailer usually only carries about 250–1000 kg of compressed hydrogen [79]. Another advantage lies in their structural configuration. Cryogenic trucks are usually made with double walls and several layers of heat shielding between them, mainly made from materials like aluminium or mylar [80]. This design helps to minimise hydrogen boil-off losses. Some larger units are also coated with liquid nitrogen to further prevent boil-off losses. The issue, however, is that this is a very energy intensive process. Liquefying hydrogen typically results in energy losses of <40 % compared to the 10% energy loss in compressed hydrogen trucks [81]. In general, about 12.5–15.0 kWh/kg is required for liquefaction compared to approx. 6.0 kWh/kg required for compression [82]. Consequently, the energy-intensive liquefaction process results in higher operational costs. Typical liquefaction capacities can range from 100 kg/H_2 to 10,000 kg/H_2

and cost \$ 9–10/kg LH_2 [82]. Despite cryogenic trucks' high initial investments, with the correct developments, they hold vast potential for future hydrogen transport. This is mainly because of their aforementioned low storage temperature (~253°C), which significantly increases the volumetric density of cryogenic trucks compared to compressed gas trucks.

In the GCC context, hydrogen trucks (both compressed gas and cryogenic) are in the early, pilot-testing phase. Saudi Arabia specifically is home to about 10 known compressed gas trucks currently [83]. Meanwhile, hydrogen pipelines are being built within industrial zones in the region, mainly for internal transport [84].

2.4 Designing and Optimisation Modelling of a Hydrogen Supply Chain Configuration

Aside from the expansion of production, storage and transportation infrastructure, for hydrogen to compete effectively with established fossil fuel systems for transport, supply chain design must balance economic viability with environmental performance and safety. Integrating these dimensions within a unified optimisation framework is essential to avoid long-term trade-offs, particularly as decarbonisation targets become more stringent. In the current research, the design of HSC networks has been broadly studied [14, 15]. The HSC problem is frequently solved using mixed integer linear programming (MILP) models. Mixed Integer Linear Programming (MILP) is a mathematical optimisation method used to find the best possible outcome (in this case the best hydrogen supply chain network design) by minimising an objective function subject to constraints. In this model, some decision variables are restricted to integer values while others can be continuous, discussed in greater detail in Chapter 3.

2.4.1 Single-Objective Optimisation

MILP can either focus on a single objective (e.g. the minimisation of cost) or focus on a multi-objective problem (e.g. the minimisation of cost and carbon footprint). Ingason et al. [85] used MILP to determine the most cost-effective sites for hydrogen production technologies in Iceland. In this work, it was found that at low demand, hydrogen remained expensive due to underutilised infrastructure, whereas high demand drove costs back up as the system reached capacity, which required new power plants and transmission lines. This suggests that there is an optimal demand ‘sweet spot’ for hydrogen production. When demand is too low, idle infrastructure is making each unit of H_2 expensive; while at high demand, the existing grid lags behind demand, forcing expensive capital investments in new plants and lines. Another study by Camelo et al. [86] employed MILP to optimise a green hydrogen supply chain in Brazil. In this work, production and storage were identified as key cost drivers, while higher demand was found to enable economies of scale to reduce production expenses. Almansoori and Shah [87] used MILP for the construction of a hydrogen supply chain in the UK. The MILP problem was solved via GAMS software to design a hydrogen supply chain network focusing on minimising total costs. Results found that the delivery of hydrogen via tube trailers became cheaper than liquid hydrogen transport as technologies developed, which subsequently resulted in the most cost-competitive HSC configuration being a gaseous hydrogen-based network, also because of the low production cost of compressed hydrogen gas. On the environmental side, Ibrahim and Mohannadi [88] used MILP to minimise the cost objective in a HSC under varying CO_2 emission mitigation policies. Results found that although the lowest levelized cost of hydrogen (LCOH) occurred when there was no emission target ($3.41/kg$H_2$), at a 50% emission offset, green hydrogen became more cost effective than blue due to the additional costs incurred by the natural gas required to generate heat for CCUS.

2.4.2 Multi-Objective Optimisation

Multi-objective optimisation, which is the approach used in this work, focuses on the minimisation of more than one objective function. Konda et al. [89] used MILP for hydrogen supply chain optimisation in the Netherlands, focusing on the minimisation of the cost and environmental functions. The study concluded that the transition towards large-scale hydrogen supply infrastructure is viable economically, but the emission reduction potential is limited to ~30 % and would require CCUS integration to improve to 85%, which would increase cost. Another study by Ogumerem et al. [90] used bi-objective MILP to maximise the net present value (NPV) and minimise GHG emissions of a hydrogen supply chain network in the state of Texas. This study found that if the oxygen co-produced with hydrogen was sold instead of discarded, electrolysis became a cost-competitive hydrogen production technology. Another study by Li et al. [91], used MILP for bi-objective optimisation to obtain a Pareto solution between cost and global warming potential (GWP) in a HSC. This study found that multi-objective MILP design provides decision-makers with visual quantifications of multi-objective trade-offs in HSC design- in this case the trade-off between cost and GWP. With respect to safety, there are few studies that have considered this objective in HSC design. Kim and Moon [92] used MILP to consider the trade-off between the economic and safety objectives of a HSC. However, this study found that any alteration in production plants, storage or transport modes (i.e. increased or decreased cost) had no significant effect on the safety. All the above multi-objective works consider a bi-objective optimisation problem. As far as works that have investigated >2 objectives, a work by Guillén-Gosálbez et al. [93] that focused on environmental concerns demonstrated that multi-objective optimisation can be made more manageable by identifying non-conflicting environmental indicators. By removing redundant metrics, the complexity of the MILP model can be reduced without a loss of critical data. The above works all solved the MILP problem via the ε-constraint method. In this method, the objective functions are sequentially optimised- i.e. one objective function is optimised at a time while the other(s) are modelled as constraints. Conversely, this research utilises the weighted-sum approach. This method combines all three objectives into a single, comprehensive function, allowing for a simultaneous evaluation of trade-offs within a unified framework; discussed in greater detail in Chapter 3.

2.4.3 Multiple-Criteria Decision-Making (MCDM): AHP-TOPSIS

In multi-objective optimisation, the Pareto-optimal state marks a threshold where no single objective can be further enhanced without causing a concurrent decline in another, effectively mapping the boundary of the system's potential as far as trade-off balance. This is what this research focuses on as far as straight mathematical optimisation. However, for a HSC network to be fully optimised, it must also be able to move from research to implementation. Accordingly, it is critical to incorporate stakeholder preferences into the supply chain design, as they (policymakers, decision-makers, investors etc.) will be the ones constructing the supply chain in practice. To achieve this, this work uses two multiple-criteria decision making (MCDM) tools across the Kuwait and Saudi Arabia case studies: analytic hierarchy process (AHP) and Technique for Order of Preference by Similarity to Ideal Solution (TOPSIS). AHP describes a measurement technique that ranks the relative importance of various criteria from expert qualitative judgements using pairwise comparison matrices. This process follows a four-stage procedure. First, a decision problem is decomposed into a multi-level hierarchy. The primary goal (i.e. the production, storage, or transportation) sits at the apex, followed by the three core objectives- in this case economic, environmental, and risk. Subsequent levels further break these down into specific criteria, sub-criteria, and alternatives [94]. Figures 4–6 and 23–25 in Chapters 4.1 and 4.3 present these matrices for the Kuwait and Saudi Arabia case studies. Following this, experts evaluate the relative importance of each criterion and sub-criterion at a given level against others in the same category. For example, in this case, in the environmental objective function for hydrogen production, the carbon footprint criterion is compared and evaluated in importance against the water consumption criterion. Rather than assigning isolated ranks, criteria are compared in pairs using a nine-point intensity scale. For instance, if carbon footprint is judged to have 'strong importance' over water consumption, it receives a score of 5, while efficiency is assigned the reciprocal value of 1/5. The nine-point intensity scale can be found in Table 3. Following the evaluation of all criteria, the resulting matrices are normalised by dividing each element by its respective column sum. From these dimensionless values, a priority vector is derived by calculating the average of each row. These weights are then scaled to ensure their sum equals unity (1.0), representing the relative influence of each factor on the objective function [94]. Because AHP relies on subjective human intuition, the logical coherence of the judgements must be validated. This is achieved by calculating the Consistency Index (CI) and the Consistency Ratio (CR) based on the maximum eigenvalue. If the CR is less than the 0.1 threshold, the rankings are deemed consistent and integrated into the MILP model. If the ratio exceeds 0.1, the stakeholder judgements are revisited and refined until logical consistency is achieved. In Luthra et al. [95], AHP was used to categorise and prioritise various supply chain factors in the plastics manufacturing sector. The results identified 'government support and policies' as the most significant determinant among the evaluated criteria, showing that even in a mature industry like plastics, ‘government support’ can outweigh technical efficiency or cost. In another study, Ren et al. [96] employed AHP to rank sustainable hydrogen supply chains in China. Notably, in this study, steam methane reforming (SMR) was the preferred production pathway. However, in practice, this wouldn’t be feasible due to national gas cost limitations in China. This highlights the risk of relying solely on subjective AHP rankings that can sometimes undermine technical optimality, demonstrating the necessity of integrating this method with mathematical MCDM tools like TOPSIS and mathematical optimisation models like MILP to ensure technical and economic feasibility. Contrarily, TOPSIS is a mathematical MCDM tool that ranks alternatives by calculating their geometric distance from both an Ideal Best Solution and an Ideal Worst Solution within a multi-criteria space [97]. The final ranking is determined by a closeness coefficient, where the top-rated option is the one that sits mathematically closest to the optimal target while remaining furthest from the most undesirable outcome [97]. Instead of just looking for the "best" score, the closeness coefficient effectively ranks based on which alternative is simultaneously closest to the ideal target and furthest away from the most undesirable outcome per criterion. This is discussed in greater detail in Chapter 3. Azadnia et al. [98] applied TOPSIS to assess risks in the European Union's green hydrogen supply chain, focusing on hard-to-abate sectors. Their analysis highlighted high capital investments and limited regional electrolyser capacity as the primary, highest-ranked factors hindering hydrogen development. Reyes-Barquet et al. [99] employed TOPSIS to determine the optimal configuration for a hydrogen supply chain (HSC) powered by agro-industrial sugarcane waste in Mexico. Their research found that, under an optimised scenario, the transport sector's utilisation of this hydrogen would account for 23% of total annual GHG emissions. Sharaf [100] utilised TOPSIS to determine that composite material-based tanks represent the optimal hydrogen storage solution for automotive applications, surpassing compressed, liquid, and metal hydride options when considering performance and uncertainty. Zhang et al. [101] used TOPSIS to identify that the safety resilience of hydrogen refuelling stations is fundamentally driven by four key factors: monitoring capabilities, equipment vulnerability, local government emergency response, and hazard distribution density. Finally, Goh et al. [102] applied the TOPSIS method to model and optimise a solar-biomass hybrid renewable energy system for industrial hydrogen production in Malaysia, achieving substantial operational improvements. The study demonstrated that incorporating this decision-making framework into the supply chain reduces annual operational costs by up to $10 million while significantly minimising energy wastage.

Table 3: AHP nine-point intensity scale

1 (Equal importance)
3 (Moderate importance)
5 (Strong importance)
7 (Very strong importance)
9 (Absolute importance)

2.4.4 Sensitivity Analysis

A sensitivity analysis is a mathematical technique used to determine how different values of an independent variable affect a particular dependent variable under a given set of assumptions [103]. It functions as a "what-if" tool that allows decision-makers to identify which input factors have the most significant impact on an outcome, thereby helping to predict risks and evaluate model robustness. In the context of hydrogen supply chains, a sensitivity analysis is particularly vital for examining how fluctuations in criteria weightings across economic, environmental and risk objectives might shift the optimal network design. By testing these volatile inputs, the exact threshold at which green hydrogen becomes a more viable alternative than traditional fossil-fuelled methods can be determined. Goh et al. [102] conducted a sensitivity analysis on their TOPSIS-optimised solar-biomass hydrogen supply chain, highlighting that prioritising reduced power loss shifts the optimal design from increased generation to enlarged solar arrays and costlier electrolysis systems. Their analysis further indicated that, to minimise energy waste, capacity for hydrogen storage must be marginally increased. Mangla et al. [104] conducted a sensitivity analysis alongside AHP for a risk analysis in green supply chains. The study identified that top hurdles to green supply chain management include inadequate government support, low senior management commitment, and supplier resistance to green initiatives. The study's sensitivity analysis confirmed that these risks are robust, and their ranking remains stable even when criteria weightings vary. Mao et.al [105] integrated sensitivity testing into an MILP-optimised framework to assess how various technical and financial parameters influence the LCOH. Their analysis found that electrolyser performance is significantly more sensitive to the price of solar electricity than to initial CAPEX, with a recorded difference of approximately 33%. Furthermore, while low-carbon solutions like CCUS were highly sensitive to fluctuating fuel prices, they remained relatively unaffected by marginal changes in system efficiency. Additionally, the study revealed that transportation distance is a critical tipping point factor; beyond a specific geographical threshold, the sensitivity of the LCOH to pipeline capital costs grows exponentially, eventually outweighing the sensitivity to production-side efficiencies.

2.4.5 Variability of Green Energy Production

A key consideration in the design of any solar-powered hydrogen supply chain is the inherent variability of renewable energy generation. Solar photovoltaic output is intermittent by nature, driven by diurnal cycles, seasonal variation, and stochastic weather events such as dust storms and cloud cover. In the GCC context, while solar irradiance is among the highest globally and relatively consistent on an annual basis, significant intra-day and seasonal variability still exists. Daily output follows a bell-curve profile peaking at solar noon, while seasonal variation results in winter months producing approximately 20–30% less electricity than peak summer months in most GCC locations. The region is also subject to frequent dust accumulation on PV panels (soiling losses). Studies have reported that a typical monthly decrease of approximately 10% of PV power output is attributable to soiling in GCC conditions [5], while in the broader Asia regions, optimal cleaning schedules every five to six days still result in median revenue losses of approximately 2.5% [6]. In Qatar specifically, soiling reduced PV output by over 40% after six months without cleaning [106]. Dust storms can cause additional episodic and substantial reductions in irradiance. These sources of variability have direct implications for hydrogen supply chain design. Electrolysers fed by variable renewable electricity must either tolerate part-load operation- which reduces efficiency- or be paired with intermediate buffer storage to smooth supply. The dynamic load-following capability of electrolysers therefore becomes a critical selection criterion: PEM electrolysers are better suited to variable operation with rapid response times, while alkaline water systems have slower response times and a more limited part-load operating range [30]. This distinction is captured in the multi-period AHP weighting framework employed in the Saudi Arabia case study. The modelling approach adopted in this thesis treats solar PV output as a fixed average capacity factor per planning period, based on reported irradiance data for each region. While this simplification does not fully capture intra-period variability, it is consistent with the temporal resolution of the MILP framework (annual planning periods) and with standard practice in long-term energy systems modelling. The implications of solar intermittency on storage sizing and electrolyser utilisation are further discussed in the relevant case study chapters.

2.5. Identified Research Gaps

The preceding review reveals a consistent and compounding pattern of methodological limitation across the hydrogen supply chain optimisation literature: studies are predominantly single-objective in formulation, static in temporal structure, single-country or single-technology in scope, and rarely embed stakeholder preferences directly within the optimisation framework itself. Taken together, these limitations establish a clear and unaddressed gap- the absence of a dynamic, multi-objective, preference-integrated supply chain optimisation framework capable of evaluating competing production, storage, and transportation technologies simultaneously under evolving demand conditions and stakeholder priorities, with specific application to the GCC region where solar resource endowment and strategic export positioning create a uniquely favourable but analytically underserved context for green hydrogen development.

Despite the rapidly expanding literature on hydrogen supply chain (HSC) optimisation, several critical limitations remain in the design of fully green hydrogen systems. First, many studies focus primarily on economic optimisation, while broader sustainability dimensions are only partially considered. In particular, the explicit incorporation of safety and risk as an optimisation objective remains limited, despite the operational hazards associated with hydrogen production, storage, and transportation. Second, existing research frequently evaluates hydrogen supply chain components in isolation or assumes a single production pathway, resulting in limited comparative analysis of alternative electrolyser technologies within integrated green hydrogen supply chain frameworks. Third, while multiple-criteria decision-making tools such as analytic hierarchy process (AHP) are increasingly used in energy system assessment, their integration within mathematical optimisation models remains limited, and stakeholder preferences are therefore rarely embedded directly in supply chain design. Next, the majority of hydrogen supply chain models are static in nature. Thus, these models typically ignore evolving decision-maker priorities over time and how they affect the performance of the optimal supply chain configuration across periods over time. Finally, despite the substantial solar resource potential of the Gulf Cooperation Council (GCC), region-specific optimisation frameworks capable of supporting long-term hydrogen infrastructure planning have not yet been developed in the literature.

To address these limitations, this research develops a methodological progression that advances existing hydrogen supply chain modelling through two complementary stages. The initial study conducted for Kuwait first establishes a foundational benchmark by addressing several key methodological gaps in the existing literature. The case study introduces a comparative evaluation of a fully green hydrogen supply chain framework, rather than assuming a single production pathway. This enables the identification of technology-specific performance trade-offs (like for example electrolyser technologies) under the climatic and operational conditions relevant to the GCC. The model also introduces safety/risk as a third optimisation objective alongside cost and environmental impact, thereby extending conventional cost-emissions trade-off models towards a more comprehensive sustainability-oriented optimisation framework. Stakeholder preferences are incorporated into the supply chain design process by comparing a neutral optimisation scenario, in which all criteria receive equal weighting, with an AHP-informed framework that reflects expert priorities. This approach enables the analysis of how stakeholder-driven decision criteria influence the resulting optimal hydrogen supply chain configuration.

Building upon this baseline, the Saudi Arabia case study introduces a significant methodological advancement that addresses the static limitations of existing hydrogen supply chain models. Specifically, the study develops a dynamic mixed-integer linear programming (MILP) optimisation framework in which AHP-derived objective weightings evolve across multiple planning periods (2025-2060). Unlike conventional approaches in which objective weights remain fixed, this formulation allows the relative importance of cost, environmental performance, and safety/risk to change over time, reflecting the evolving priorities typically observed during the maturation of emerging energy systems. In addition, the multi-period framework enables the analysis of long-term infrastructure development pathways under varying demand scenarios, capturing the temporal evolution of hydrogen production, storage, and transportation systems. This provides a more realistic representation of hydrogen supply chain planning by accounting for the path dependency associated with large-scale infrastructure investments.

Together, these studies contribute to the advancement of hydrogen supply chain modelling by:

Introducing tri-objective optimisation incorporating cost, environmental impact, and safety/risk; providing a comparative evaluation of multiple production, storage and transportation technologies within a fully green hydrogen supply chain framework; embedding stakeholder preferences within optimisation-based supply chain design; and introducing a dynamic MILP formulation with time-dependent AHP weightings for long-term hydrogen infrastructure planning.

This research also provides one of the first optimisation-based planning frameworks tailored to the GCC region, supporting the strategic development of solar-driven hydrogen supply chains under evolving technological, economic, and policy conditions.

3. Methodology

3.1 Research Design

The overarching research design is a model-based optimisation framework with explicit integration of stakeholder preferences through multiple-criteria decision-making (MCDM). The study is structured as a two-stage methodological development, progressing from a static benchmark model in the Kuwait study to a dynamic, time-adaptive optimisation framework in the Saudi Arabia study. The Kuwait case study is designed as a static, preference-integrated optimisation. Here, a baseline optimisation architecture is established by integrating stakeholder preferences into a single-period (2050), tri-objective MILP framework. The model simultaneously minimises cost, carbon footprint, and a newly introduced safety/risk objective, while explicitly evaluating alternative configurations across production, storage, and transportation stages. The research design is constructed around two parallel modelling structures. First, the baseline no-priority optimisation (i.e. baseline configuration) assigns equal weightings to all decision criteria across the MILP framework. For production and storage, ten criteria are considered, thus, each criterion is assigned a weight of 0.1 ($w_k = 0.1$) while eleven criteria are used for transportation ($w_k = 1/11$).

$$\min Z = \sum_k w_k \cdot f_k(x) \qquad (1)$$

where, $f_k(x)$ represents the normalised performance of criterion k and w_k denotes the corresponding weight.

The MILP model optimises the total aggregated criteria score across the supply chain. In parallel, a TOPSIS analysis is conducted to rank alternatives based on their relative distance to ideal and non-ideal solutions, again with all criteria weighted equally. This dual structure enables a methodological comparison between optimisation-based selection (MILP) and distance-based ranking (TOPSIS) under identical, non-preferential conditions. To move beyond equal weighting assumptions and integrate stakeholder considerations, AHP is applied to derive the criteria-specific weightings based on expert judgement. These weights are first integrated into the TOPSIS analysis to refine the ranking of individual technologies, and subsequently embedded within the MILP objective function, replacing equal weights with preference-driven coefficients. This design allows for a direct comparison between neutral (equal-weighted) and preference-informed optimisation outcomes, enabling the identification of deviations between technically optimal and stakeholder-aligned configurations. In this context, TOPSIS serves as both a robustness tool, and a validation and interpretive layer, ensuring that technically optimal MILP-derived solutions are consistent and similar to subjective, multiple-criteria ranking logic. In this case study, low, medium and high demand scenarios are analysed in each of the MILP, TOPSIS and AHP-TOPSIS frameworks based on the projected penetration rate of green hydrogen in the transport sector, to determine the impact fluctuating demand has on the optimal configuration.

Building on the Kuwait baseline, the Saudi Arabia case study extends the MILP-AHP framework into a multi-period, dynamically weighted optimisation model. Unlike the Kuwait case study, in which TOPSIS is applied alongside MILP to provide a complementary distance-based ranking, TOPSIS is not employed in the Saudi Arabia framework, as its inherently static ranking structure is incompatible with the temporal continuity required by a multi-period optimisation model. As such, all scores reported for Saudi Arabia derive exclusively from the dynamic MILP-AHP formulation. The system is modelled over four planning periods (2025, 2035, 2045 and 2060), incorporating low, medium, and high demand scenarios in each year to capture uncertainty in hydrogen market development. In this case study, the core methodological advancement lies in the development of a dynamic weighted-sum MILP formulation, in which objective function weights are treated as time-dependent variables rather than fixed parameters, as follows:

$$\min\ Z_t = \sum_k w_{k,t} \cdot f_k(x_t) \qquad (2)$$

where, $w_{k,t}$ represents the weight of criterion k in planning period t. These weights are derived from AHP-pairwise comparisons conducted for each planning period, reflecting anticipated shifts in stakeholder priorities over time. More specifically: early-stage periods assign greater importance to economic feasibility (i.e. criteria such as CAPEX), while later periods progressively increase weighting on environmental performance criteria, such as carbon footprint. These evolving weights are directly embedded within the MILP objective function, allowing the optimisation process to adapt endogenously to changing decision priorities across time. Like in the Kuwait case study, the Saudi Arabia case study focuses on scenario-based demand variation, based on the different hydrogen demand penetration pathways across time. However, unlike the Kuwait case study, TOPSIS is not applied in the Saudi Arabia study due to fundamental methodological limitations in handling dynamic, multi-period optimisation problems. As TOPSIS is inherently a static ranking method, applying TOPSIS in this context would require decoupling each time period into independent ranking problems, thereby breaking the temporal continuity of the optimisation model and undermining the representation of long-term infrastructure planning. Instead, this case study adopts a fully integrated dynamic MILP approach, in which AHP-derived preferences are embedded directly into the optimisation structure. Subsequently, this ensures that stakeholder priorities influence decisions within the optimisation process itself and that system evolution is determined endogenously rather than through post hoc ranking.

3.2 Data Collection

The empirical data collection for this research was done via systematic extraction from existing literature and databases. As far as demand projections, for the Kuwait case study, the International Energy Agency (IEA) projects that hydrogen demand in the transport sector is expected to amount to 25% of total demand across all industries in Kuwait by 2050 [107]. Other analyses [108,109] also concluded similar findings. For the scenario-based analysis in this study, the 25% projection is used as a baseline, with conservative variations to reflect market uncertainty and policy evolution-i.e. the low, medium and high demand scenarios. Specifically, green hydrogen demand in the transport sector in the Kuwait case study is defined follows: low demand- 12.5% (representing 50% of the baseline projection), medium demand- 13.8% (55% of baseline), and high demand- 16.3% (65% of baseline). These scenarios correspond to energy demand values expressed in kWh, derived from the statistics regarding the projected penetration rate of hydrogen fuel cell electric vehicles (HFCVs) reported in the aforementioned literature. A similar approach was used for Saudi Arabia. For period 1 (2025), the known operational hydrogen vehicles in Saudi Arabia (presently 10) [110-111] were used to calculate demand. For each of these vehicles, the production of 1kg/ H_2 fuel via electrolysis requires 60 kWh of electricity, with each vehicle yielding a consistent driving operation of 400 km [112]. In this case study, demand values expressed in kW represent the average equivalent power required to produce the corresponding hydrogen demand via electrolysis on an annual basis. Converted to kW per vehicle, this yields- for 2025- a high demand scenario of 9 kW, so total high demand in this period is accepted as 90 kW based on the existing operational hydrogen vehicles in Saudi Arabia. Medium demand is considered 50% of high demand (45 kW for 2025) and low demand is considered 20% of high demand (18 kW). For the subsequent years analysed (2035, 2045 and 2060), the demand projections were also obtained according to demand projection reports. For 2035, Saudi Arabia is aiming for a green hydrogen production of 4 MTPA, with about 5% to be used for domestic transport [113]. This, therefore, yields a high demand of 760,000 kW for 2035. Using the same 50%, 20% breakdowns for medium and low demands this yields demands of 380,000 kW (medium) and 152,000 kW (low) for 2035, respectively. 2045 and 2060 demands are calculated using the same approach, accounting for Saudi Arabia's targeted hydrogen production in these years reported by the King Abdullah Petroleum Studies and Research Center (KAPSARC) [114] and the share of this production being allocated towards domestic HFCVs in 2045 and 2060. The full demands for both Kuwait and Saudi Arabia can be found in Chapters 4.1. and 4.2.1.

For electrolyser capital costs, operational costs and their projected evolution between 2025-2060, the data was obtained via the International Energy Agency (IEA)'s electrolyser technology data reports [115,116] and the IEA's levelized cost of hydrogen maps [117]. It should be noted that the efficiency values cited for each electrolyser technology vary across planning periods, reflecting projected improvements in technological performance over time as captured in the R&D trajectories embedded within the multi-period model; figures cited in earlier periods therefore represent current or near-term performance, while those in later periods reflect anticipated maturation under sustained investment and deployment.

Green hydrogen projects across Kuwait and Saudi Arabia currently use ThyssenKrupp technologies. Accordingly, the company database was used to obtain production criteria such as purity, capacity and efficiency, lifetime [118]. For storage and transportation, the data was obtained from the Ministry of Foreign Affairs and federal research institutes, namely Anwar Gargash Diplomatic Academy [119, 120].

With respect to salt cavern storage input parameters specifically, the following assumptions and data sources are noted for transparency. The capital cost (CAPEX) for salt cavern construction was derived from published estimates for GCC-analogous projects, based on depleted oil reservoir conversion costs reported in the literature for the GCC context [118, 119], with values expressed on a per-unit-capacity basis (\$/kg H_2 stored). The storage capacity assumption is based on an estimated 5% depletion rate applied to each GCC country's total national oil field volumes, as reported by OPEC [78], yielding the total available volume for conversion. The storage efficiency parameter (approximately 95%) is representative of underground geological storage under operational conditions, accounting for minor hydrogen losses due to pressure management and gas cushion requirements. The operational pressure range (up to 200 bar, depending on cavern depth) is consistent with published technical feasibility ranges for underground hydrogen storage in salt formations. The risk index assigned to salt cavern storage reflects its low surface infrastructure requirements and inherent geological containment, resulting in lower assigned risk relative to surface storage technologies. The operational lifetime is assumed to be 30 years, consistent with established geological storage infrastructure in the oil and gas sector.

Regarding the stakeholder survey conducted as part of the AHP weighting process: the survey was administered to a panel of 10 hydrogen energy experts, comprising academics, industry professionals, and policy advisors with relevant expertise in hydrogen supply chain design, GCC energy systems, and green infrastructure planning. Respondents were recruited through professional networks associated with the research team and through direct invitation to individuals with demonstrated expertise in the subject area. The survey was administered electronically using a structured pairwise comparison questionnaire based on Saaty's nine-point intensity scale. Each respondent independently completed pairwise comparisons for all criteria within each supply chain stage (production, storage, and transportation), and across both the Kuwait (single-period) and Saudi Arabia (multi-period, four-period) case studies. Individual responses were aggregated using the geometric mean method to produce a single consolidated pairwise comparison matrix per stage per period, consistent with standard AHP group decision-making practice. The resulting priority vectors (AHP weights) were then validated for logical consistency using the Consistency Ratio (CR) test, with all matrices confirmed to have $CR < 0.10$ prior to integration into the MILP framework. The full AHP matrices and derived weightings for all supply chain stages and planning periods are presented in Appendix B (Kuwait) and Appendix C (Saudi Arabia).

Since the collected data, especially future demand projections and technology cost estimates, are based on projections from literature and databases rather than observed field measurements, a sensitivity analysis was conducted in each case study to evaluate how uncertainties in these data inputs affect the resulting optimal supply chain configurations and ensure robustness.

3.3 Mathematical Modelling

3.3.1 Mixed Integer Linear Programming (MILP)

The original mathematical framework initially developed by Almansoori and Shah [87] is first employed in this work and extended to a multi-objective context by incorporating environmental and safety/risk objectives, alongside economic.

Sets and Indices

The sets and indices defining the structural dimensions of the optimisation model, capturing spatial, technological, and temporal components, are as follows:

Table 4: MILP formulation: Sets and Indices:

Symbol	**Description**
(g)	*grid/location node*
(g')	*destination grid*
(p)	*production technology*
(s)	*storage technology*
(l)	*transportation mode*
(t)	*planning period*

Parameters

The model parameters, representing the fixed quantitative data that govern production, storage, transportation, and operational characteristics, are defined as follows:

Table 5: MILP formulation: Parameters:

Parameter	**Description**
$D_{g,t}$	*hydrogen demand at grid (g) at period (t)*
$\left(Cap_p^P\right)$	*production capacity of technology (p)*
(Cap_s^S)	*storage capacity of technology (s)*
$FCC_{p,g}$	*facility capital cost*
$TCC_{l,g,g'}$	*transport infrastructure capital cost*
$FOC_{p,g}$	*facility operating cost*
$TOC_{l,g,g'}$	*transport operating cost*
$ESC_{l,g,g'}$	*Transport energy cost*
GP_p	*carbon footprint per kg* H_2 *produced*
GS_s	*carbon footprint per kg* H_2 *stored*
GT_l	*carbon footprint per kg* H_2 *per km transported*
$AG_{l,g,g'}$	*distance between grids for transport mode l*
RP_p	*risk index for production*
RS_s	*risk index for storage*
RT_l	*risk index for transport*
CCF	*capital charge factor*
α	*project lifetime*

Decision Variables

The decision variables, representing the controllable quantities within the optimisation model that determine production, storage, transportation, and infrastructure deployment across all periods, are defined as follows:

Table 6: MILP formulation: Decision Variables:

Variable	**Description**	**Variable Type**
$P_{p,g,t}$	*hydrogen produced at plant (p), grid (g), period (t)*	Continuous
$S_{s,g,t}$	*hydrogen stored using storage (s), at grid (g), period (t)*	Continuous
$H_{l,g,g',t}$	*hydrogen transported from grid (g) to (g') using mode (l) at period (t)*	Continuous
$Y_{p,g,t}$	*1 if production facility built/active, period (t)*	Binary
$Z_{s,g,t}$	*1 if storage facility built/active, period (t)*	Binary
$X_{l,g,g',t}$	*1 if transport mode built/active, period (t)*	Binary

3.3.2 Objective Functions

Economic Objective

The economic objective function calculates the total cost (TC, in \$) of establishing and operating the hydrogen supply chain, including production, storage, and transportation across all planning periods. Investment decisions and operational costs (e.g. total HSC CAPEX and OPEX) are also included in this function:

$$TC = \sum_{t} [\sum_{p,g} P_{p,g,t} \cdot FOC_{p,g} + \sum_{s,g} S_{s,g,t} \cdot SOC_{s,g} + \sum_{l,g,g'} H_{l,g,g',t} \cdot TOC_{l,g,g'} + \sum_{p,g} \frac{FCC_{p,g} \cdot Y_{p,g,t}}{\alpha \cdot CCF} + \sum_{s,g} \frac{SCC_{s,g} \cdot Z_{s,g,t}}{\alpha \cdot CCF} + \sum_{l,g,g'} \frac{TCC_{l,g,g'} \cdot X_{l,g,g',t}}{\alpha \cdot CCF} + \sum_{l,g,g'} H_{l,g,g',t} \cdot ESC_{l,g,g',t}] \quad (3)$$

where, the total cost (TC, in \$) is calculated by annualising the capital costs of facilities (*FCC*) and transportation (*TCC*) over the network's operating period (α) using the capital charge factor (*CCF*). The resulting annualised capital cost is then added to the operating costs of facilities (*FOC*) and transportation (*TOC*), as well as the energy costs for transportation (*ESC*), to determine the overall TC.

Environmental Objective

The environmental objective defines the total carbon footprint (measured in kgCO$_2$e) of hydrogen production, storage and transportation across planning periods:

$$CF_{tot} = \sum_{p,g,t} P_{p,g,t} \cdot GP_p + \sum_{s,g,t} S_{s,g,t} \cdot GS_s + \sum_{l,g,g',t} H_{l,g,g',t} \cdot GT_l \cdot AD_{l,g,g'} \quad (4)$$

where, ($P_{p,g,t}$) is the hydrogen produced at plant p grid g at time period t and (GP_p) is the carbon footprint per kg/H_2 produced at plant p. ($S_{s,g,t}$) is the hydrogen stored using technology s at grid g and GS_s is the carbon footprint per kg/H_2 stored for that technology. ($H_{l,g,g',t}$) is the hydrogen transported using mode l from grid g to g' in period t. (GT_l) is the carbon footprint per kg/H_2 per km for transportation mode l and $AD_{l,g,g'}$ is the distance between grids.

Risk Objective

The safety/risk objective quantifies the total operational risk of the hydrogen supply chain across production, storage, and transportation stages over all planning periods. It is calculated as:

$$TR = \sum_{p,g,t} P_{p,g,t} \cdot RP_p + \sum_{s,g,t} S_{s,g,t} \cdot RS_s + \sum_{l,g,g',t} H_{l,g,g',t} \cdot RT_l \cdot AD_{l,g,g'} \qquad (5)$$

where, ($P_{p,g,t}$) is the hydrogen produced at plant p grid g at time period t and RP_p is the risk index per kg/H_2 produced at plant p. ($S_{s,g,t}$) is the hydrogen stored using technology s at grid g and RS_s is the risk index per kg/H_2 stored with technology (s). ($H_{l,g,g',t}$) is the hydrogen transported using mode l from grid g to g' in period t and (RT_l) is the risk index per kg/H_2 per km for transportation mode l and $AD_{l,g,g'}$ is the distance between grids.

3.3.3 Weighted Sum Method- Traditional

In the weighted sum method, the three objective functions (economic, environmental and risk) are combined into a single objective function by multiplying each objective by a specific weight. The objectives are first normalised by adjusting the values of the objectives so that they have defined constraints that lie on a common scale between 0 and 1. Once the units are standardised, a combined objective function is constructed by summing the weighted normalised objectives. The problem is then converted into a single objective optimisation problem, as follows:

$$\min \mathrm{Z(x)} = \mathrm{w_1} \,.\, \mathrm{Z_1(x)} + \mathrm{w_2} \,.\, \mathrm{Z_2(x)} + \mathrm{w_3} \,.\, \mathrm{Z_3(x)} \ldots \ldots . + \mathrm{w_n} \,.\, \mathrm{Z_n(x)} \qquad (6)$$

where, (Z_n) represents objective function 'n' and (w_n) represents the respective weight of the objective function. For the objectives optimised in this work, the combined single objective is calculated as:

$$\min \mathrm{w_1}.\mathrm{TC} + \mathrm{w_2}.\mathrm{CF}tot + \mathrm{w_3}.\mathrm{TR} \qquad (7)$$

3.3.4 Weighted Sum Method- Dynamic

In the novel dynamic weighted sum method proposed in the Saudi Arabia case study, weightings are no longer static and instead, are automatically updated for each planning period based on the derived stakeholder preferences using the integrated AHP-MILP framework. The weightings of each objective function are time-dependent, reflecting the evolution of stakeholder priorities and system conditions across multiple planning periods. The single-objective function for period t is expressed as:

$$\min\ Z(t) = \sum_{n=1}^{N} w_n(t) \cdot Z_n(x) \qquad (8)$$

where, $Z_n(x)$ represents objective (n) (i.e. economic, environmental or risk), $w_n(t)$ is the dynamically updated weight for objective n at planning period t and N is the total number of objectives. For this study $N = 3$.

3.3.5 Constraints

The subsequent constraints define the physical, operational, and temporal limitations of the hydrogen supply chain in this work, ensuring that production, storage, and transportation decisions remain feasible while satisfying demand across all locations and planning periods.

Demand Satisfaction:

Ensures that hydrogen supply at each grid node meets or exceeds the corresponding demand in each planning period by accounting for local production, inflows, and outflows, as follows:

$$\sum_{p} P_{p,g,t} + \sum_{l,g'} H_{l,g',g,t} - \sum_{l,g'} H_{l,g,g',t} \geq D_{g,t}, \forall g, t \tag{9}$$

Production Capacity

Limits hydrogen production at each facility to its installed capacity, conditional on the facility being operational, as follows:

$$P_{p,g,t} \leq \mathrm{Cap}_{p}^{P} \cdot Y_{p,g,t}, \forall p, g, t \tag{10}$$

Storage Capacity

Restricts the amount of hydrogen stored at each location to the maximum capacity of the selected storage technology, as follows:

$$S_{s,g,t} \leq \mathrm{Cap}_{s}^{S} \cdot Z_{s,g,t}, \forall s, g, t \tag{11}$$

Transport Capacity

Constrains hydrogen flows between grid nodes based on the capacity of the selected transportation infrastructure, as follows:

$$H_{l,g,g',t} \leq \mathrm{Cap}^{T}_{l,g,g'} \cdot X_{l,g,g',t}, \forall l, g, g', t \qquad (12)$$

Storage Balance

Tracks the temporal evolution of stored hydrogen by linking storage levels across consecutive periods, accounting for production inflows and transport outflows, as follows:

$$S_{s,g,t} = S_{s,g,t-1} + P_{p,g,t} - \sum_{g'} H_{l,g,g',t}, \forall s, g, t \qquad (13)$$

Multiperiod Linkages

Ensures infrastructure continuity by enforcing that facilities, once established, remain active in subsequent planning periods, as follows:

$$Y_{p,g,t} \geq Y_{p,g,t-1}, Z_{s,g,t} \geq Z_{s,g,t-1}, X_{l,g,g',t} \geq X_{l,g,g',t-1} \qquad (14)$$

Binary/ Non-Negativity

Define the domain of decision variables, ensuring that infrastructure decisions are binary and that all flow and storage variables remain non-negative, as follows:

$$Y_{p,g,t}, Z_{s,g,t}, X_{l,g,g',t} \in \{0,1\}, P_{p,g,t}, S_{s,g,t}, H_{l,g,g',t} \geq 0 \qquad (15)$$

3.4 Technique for Order Preference by Similarity to Ideal Solution (TOPSIS)

In TOPSIS, the criteria are normalised on a scale between 0 and 1, as follows:

$$X_{n,ij} = \frac{X_{ij}}{\sqrt{\sum_{i=1}^{n} X_{ij}^2}} \tag{16}$$

where, ($X_{n,ij}$) is the normalised value of criterion *j* for alternative i, and *n* is the total number of alternatives.

The weighted normalised matrix is then obtained by multiplying each criterion by its corresponding weight, as follows:

$$V_{ij} = X_{n,ij} \cdot W_j \tag{17}$$

Best (V_j^+) and worst (V_j^-) values for each criterion are determined, taking into account whether a criterion is beneficial or non-beneficial. Distances of each alternative from the ideal and anti-ideal points are computed as:

$$S_i^+ = \sqrt{\sum_{j=1}^{m} (V_{ij} - V_j^+)^2}, \tag{18}$$

$$S_i^- = \sqrt{\sum_{j=1}^{m} (V_{ij} - V_j^-)^2} \tag{19}$$

Finally, the relative closeness to the ideal solution is calculated:

$$P_i = \frac{S_i^-}{S_i^+ + S_i^-} \qquad (20)$$

Higher P_i values indicate alternatives closer to the ideal solution and thus, higher rankings.

3.5 Methodological Limitations and Mitigation Strategies

The optimisation and ranking methodologies employed in this study, specifically the dynamic MILP framework and the TOPSIS multi-criteria evaluation- rely on several simplifying assumptions and fixed input parameters, especially in the years analysed across both case studies (2035, 2045, 2050 and 2060) where hydrogen demand is projected. These assumptions include- for the MILP: assumption of linear trade-offs between objectives and deterministic cost, demand, and risk parameters within each planning period. Meanwhile for TOPSIS, criteria are static and given equal importance unless explicitly weighted. These assumptions introduce sensitivity to variations in hydrogen demand projections, technology capital and operational costs, and risk indices. To address this, a robustness assessment was conducted using sensitivity analysis and scenario-based evaluation, as follows:

3.5.1 Sensitivity Analysis

The sensitivity analysis was designed to assess the stability of technology rankings and optimal solutions under incremental variations in individual criterion weights for all production, storage, and transportation criteria across the hydrogen supply chain. This analysis was conducted for the high-demand no-priority TOPSIS in the Kuwait case study, while for Saudi Arabia, the sensitivity analysis was conducted for the high-demand 2060 AHP-MILP hybrid. In both cases, the sensitivity analysis was conducted for the highest-demand scenario as a stress test, as this represents the conditions where the supply chain operates at peak performance and maximum capacity. Under these conditions, limitations and constraints become the most pronounced, making the HSC’s performance more susceptible to shifts in criteria weightings. Although in both cases, the AHP analysis already introduces a systematic weighting variation based on stakeholder preferences, it doesn’t explicitly test the impact of incremental weight changes on the supply chain outcomes. As such, for Kuwait, the sensitivity analysis was conducted in the no-priority TOPSIS, where all criteria are initially considered equally important, to evaluate how ranking outcomes shift under different weighting scenarios. Conversely, for Saudi Arabia, although the dynamic MILP framework incorporates time-varying AHP-derived weightings to reflect the evolving importance of criteria across planning periods, these weights remain fixed within each time period. As such, the sensitivity analysis in this case tests whether the optimal solutions identified by the dynamic MILP remain stable when individual criteria are emphasised or de-emphasised, thereby quantifying the impact of incremental deviations from the assigned weightings that are not explicitly captured within the core optimisation.

The methodology for the sensitivity analysis applied was as follows:

For each criterion across production, storage, and transportation, weights were incrementally varied such that:

$$w_i \in [0,1] \qquad (21)$$

The remaining weight (i.e., $1 - w_i$) was evenly distributed among all other criteria within the same category, according to:

$$\sum_{j=1}^{N} w_j = 1, j \neq i \qquad (22)$$

$$w_j = \frac{1 - w_i}{N - 1}, \forall j \neq i \qquad (23)$$

where, w_i is the weight assigned to criterion i, w_j is the weight of the remaining criteria, and N is the total number of criteria within the respective category (i.e. production, storage, or transportation).

As an example, in the case of hydrogen production, if a given criterion (e.g. production capacity) was assigned a weight of $w_i = 0.4$, the remaining weight $(1 - w_i) = 0.6$ was equally distributed among the remaining $N - 1$ criteria, resulting in:

$$w_j = \frac{0.6}{10} = 0.06$$

The same procedure was applied across all production, storage and transportation criteria.

The results of the sensitivity analyses for both Kuwait and Saudi Arabia are presented in Chapters 4.1.3 and 4.2.5. These analyses highlight the robustness of the MILP-derived optimal solutions under incremental deviations from assigned weights, as well as the most influential criteria that significantly affect technology selection and system performance across economic, environmental and safety/risk objectives.

By integrating the sensitivity analysis, this research accounts for parameter uncertainty and potential stakeholder preference fluctuations, strengthening the confidence in the derived supply chain configurations and highlighting areas where policy or investment decisions may have the largest impact. Additionally, scenario-based variations in low, medium, and high demand pathways further complement the robustness assessment by capturing broader market and policy uncertainties.

4. Regional Case Studies

4.1 GCC-Specific Modelling Considerations

The climatic and physical conditions of the GCC region introduce operational constraints that are not captured in standard hydrogen supply chain parameter sets and require explicit methodological accommodation. Both case studies therefore incorporate region-specific adjustments to reflect the realities of large-scale hydrogen system operation in an arid, water-scarce environment. Operational and maintenance costs (OPEX) are marginally increased across all supply chain stages to account for the elevated cooling requirements and the higher cost of process water, which in the GCC context is predominantly sourced through energy-intensive desalination rather than conventional freshwater supply. With respect to transportation, both case studies assume the construction of entirely new pipeline infrastructure for hydrogen delivery, rather than retrofitting existing natural gas networks- a decision justified by the thermodynamic and materials incompatibility of hydrogen with conventional natural gas pipeline specifications, as discussed in Chapter 2.3.3. For risk assessment, production, storage, and transportation technologies are each classified under a standardised three-tier risk framework- low, moderate, or high- applied consistently across both case studies to ensure comparability of safety and risk outcomes. The risk classifications adopted are presented in Table 7.

Table 7: Three-tier risk framework for hydrogen production, storage and transportation methods

Production	**Risk rating**	**Reasoning**	
AEM	Moderate	• Works in a highly diluted alkaline environment, making it safe to handle. • Gas cross-permeation between hydrogen and oxygen can cause ignition.	[121] [122]
PEM	Moderate	• The chemical modification of the solid polymer electrolyte or use of catalytic H_2/O_2 recombiners can maintain crossover values at a safe level. • Like with AEM, there is the potential risk of ignition from the hydrogen/oxygen gas crossover.	[123] [124]
Alkaline water	High	• Low performance caused by the thick membrane used increases the electrical resistance and subsequently, the risk for ignition caused by a potential hydrogen/ oxygen gas crossover.	[125]

Storage			
Compressed hydrogen (tanks)	High	• In its gaseous state, hydrogen is stored at high pressures (350-700 bar), resulting in a higher risk of explosion in the event of road accidents or fires.	[126]
Salt caverns	Low	• Salt caverns offer safe and efficient possibilities for underground hydrogen storage. • Underground rock salt formations are generally impermeable, meaning that the gas cannot escape and is not exposed to external influences that could contaminate it. • Depending on their depth, salt caverns may be operated at pressures up to 200 bar, allowing for large-volume hydrogen storage to be safely stored under pressure.	[127] [128] [129] [130]
Cryogenic/liquid hydrogen	Moderate	• Adequate ventilation will help reduce the possible formation of flammable mixtures in the event of a hydrogen leak or spill and helps to eliminate the potential hazard of asphyxiation. • Nonetheless, there still lies the potential risk of both. • Liquid hydrogen evaporates almost immediately upon release, due to the rapid increase in temperature above its boiling point	[131] [132] [132]

		(-252.8 °C). Ignited releases can result in flash fires, pool fires, and deflagrations (primary and secondary).	
Transportation			
Trucks (compressed gas)	Moderate	• Like compressed storage, hydrogen gas trucks operate at very high pressure (350-700 bar), making this system susceptible to potential fire hazards, due to the two risk factors of high pressure and medium ignitability. • However, these risks only present in the unlikely failure of a hydrogen fuel system and the ignition of the subsequently released compressed hydrogen.	[133] [134]
Pipelines	Low	• Correct infrastructural developments for hydrogen pipelines can prevent and mitigate risks when accounting for human, environmental and financial parameters.	[135]
Cryogenic trucks	Moderate	• Liquefied hydrogen in poorly insulated or uninsulated tanks can liquefy the surrounding air in the event of a leakage. • If there is a gas leak in a cryogenic hydrogen storage tank the liquid hydrogen will turn into gaseous hydrogen due to boil-off, which adds the risks of fire hazards present in hydrogen gas trucks.	[136] [137]

4.2 Kuwait

For geospatial representation, Kuwait is divided into 15 grids (Figure 1) considering the mainland area (excluding Bubiyan and Az Zawr islands). Each grid represents an area where green hydrogen can be produced, stored and transported via all assessed methods presented in Figure 2.

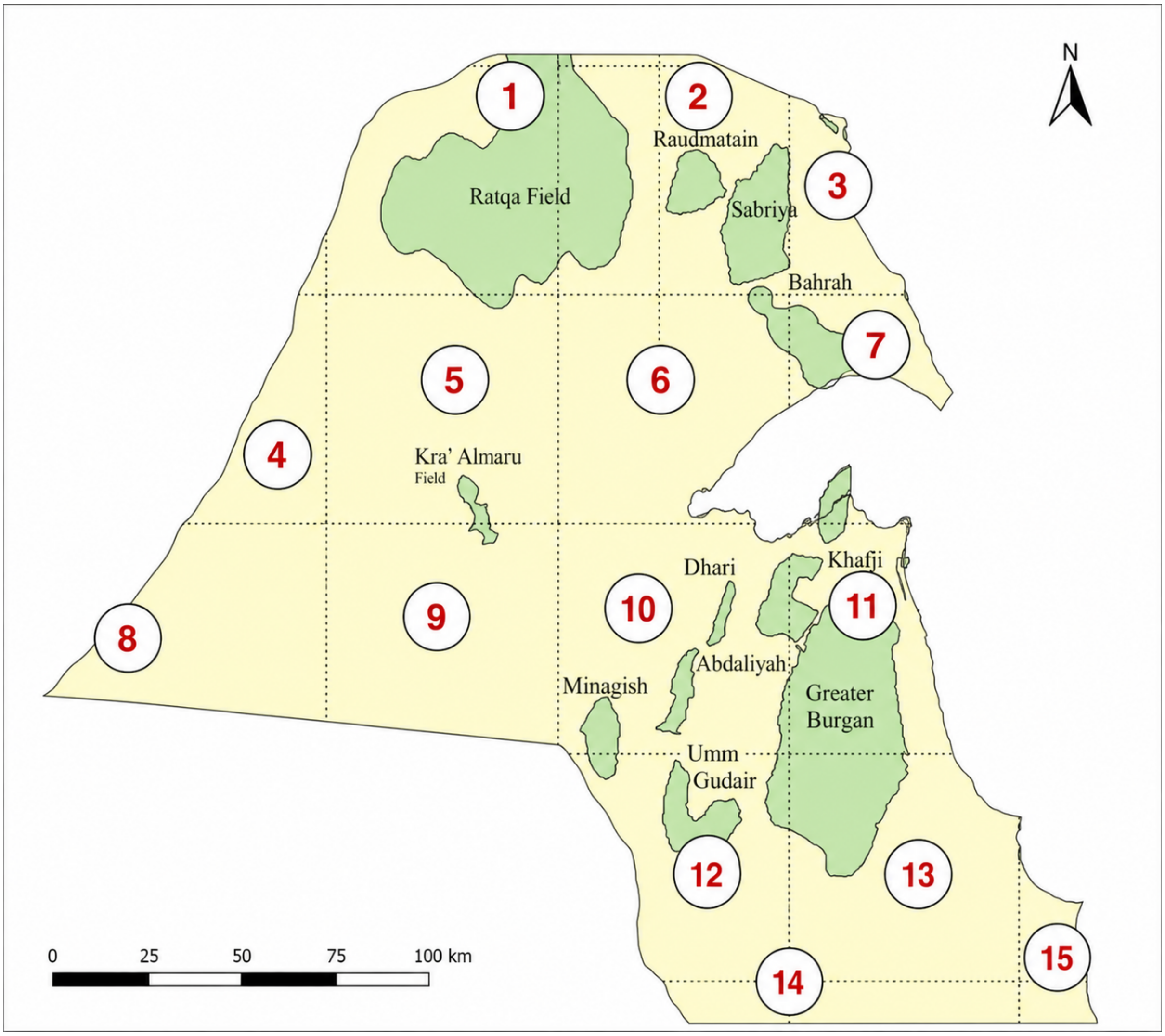


Figure 1: Kuwait geospatial grids

The green areas in Figure 1 represent Kuwait's existing oil fields, where 5% of each field is assumed to be depleted and suitable for conversion into salt cavern storage for hydrogen, as per the analysis in Chapter 2.3.2.

The results in the subsequent case studies are each evaluated under low, medium and high demand scenarios for sufficient consideration of demand fluctuations. Chapter 4.1.1. presents the results for the weighted-sum MILP HSC network under a no-priority assumption, where no explicit weighting is assigned to individual criteria. Chapter 4.1.2. evaluates the no-priority TOPSIS framework, enabling comparative ranking of technologies without preference weighting. Chapter 4.1.3. extends this analysis through the integration of AHP-derived weights within the TOPSIS framework, thus incorporating stakeholder-driven prioritisation into the decision-making process. The demand scenarios are defined based on the analysis in Chapter 3.2., which projects HFCV demand within Kuwait's transport sector in 2050. To recapitulate, the demand levels assessed in the case studies are 12.5% for low demand, representing a 50% green hydrogen penetration rate of a 25% total baseline, 13.8% (55% of 25%) for medium 16.3% (65% of 25%) for high. The hydrogen demand values, expressed in kWh, along with the associated penetration rates, are summarised in Table 8.

Table 8: Kuwait green hydrogen demand projections 2050

Penetration rate		**Green hydrogen demand (kWh)**
Low	12.5%	**15,000,000**
Medium	13.8%	**20,000,000**
High	16.3%	**25,000,000**

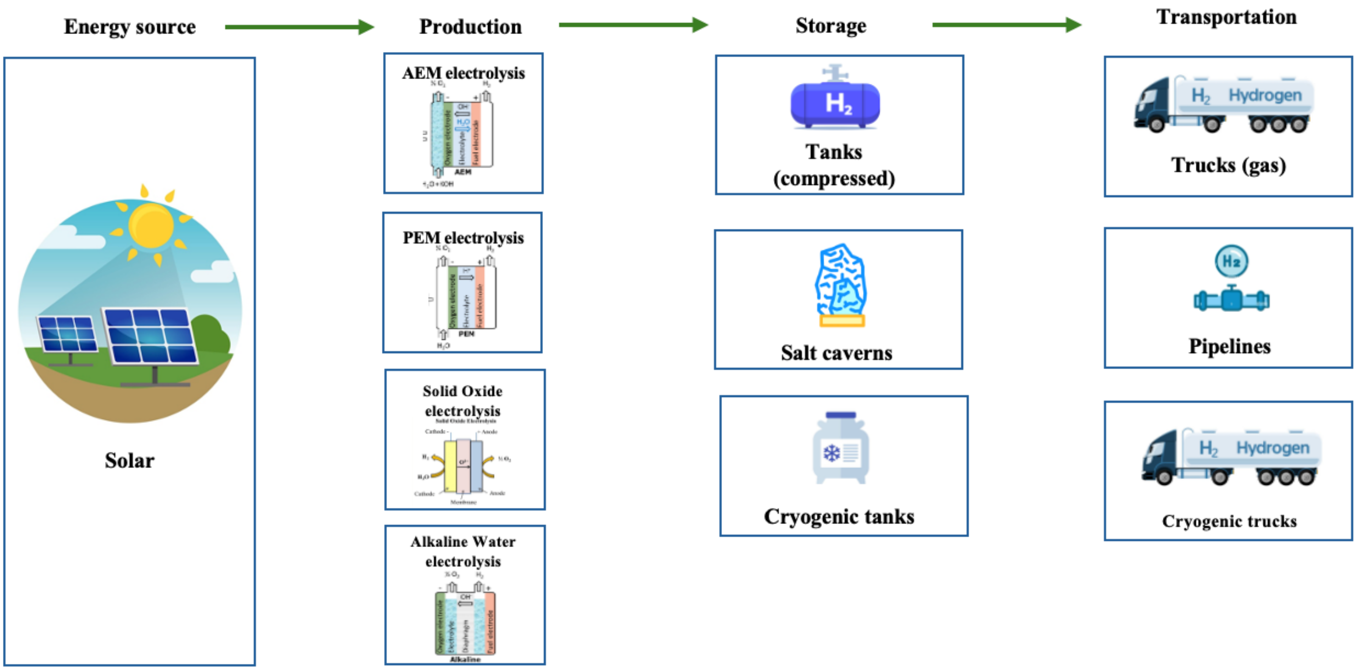


Figure 2: Kuwait hydrogen supply chain network configuration and assessed technologies

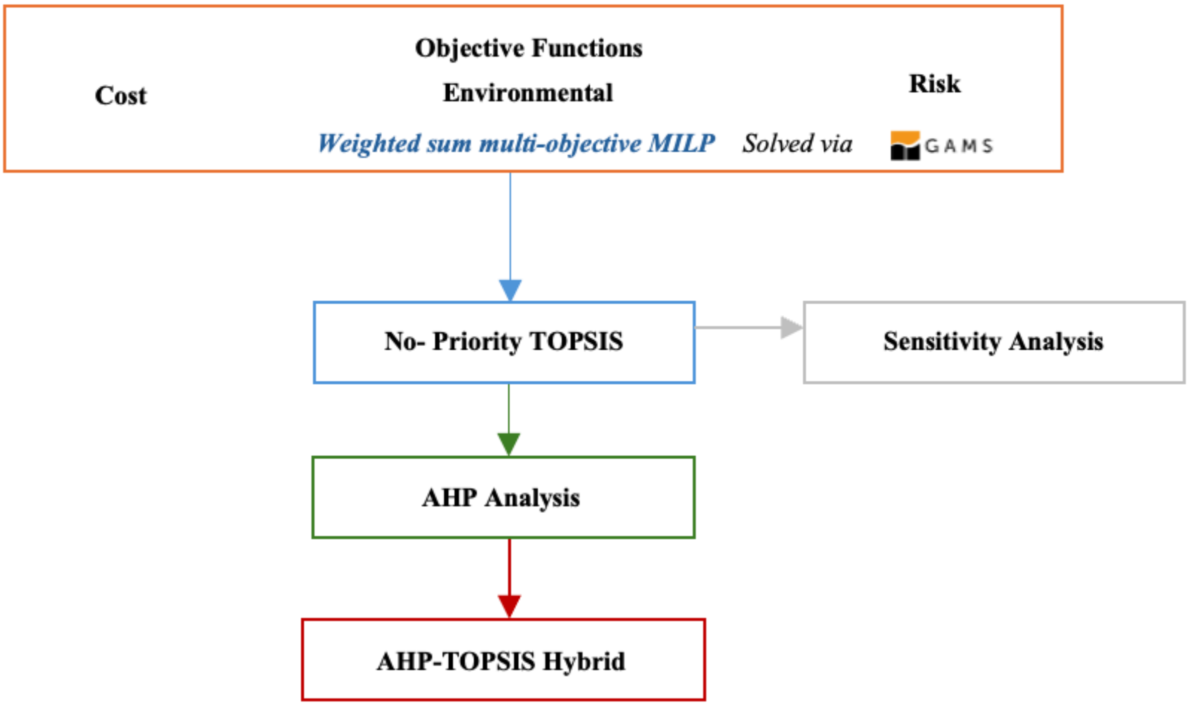


Figure 3: Schematic overview of the integrated MILP–AHP–TOPSIS optimisation framework- Kuwait

Figures 4–6 present the pairwise comparison matrices for the criteria analysed across production, storage and transportation for the Kuwait case studies. These matrices follow a hierarchal structure in which the overall objective function represented at the top level, followed by the evaluation criteria, and subsequently the decision alternatives, enabling systematic comparison of relative importance across each level.

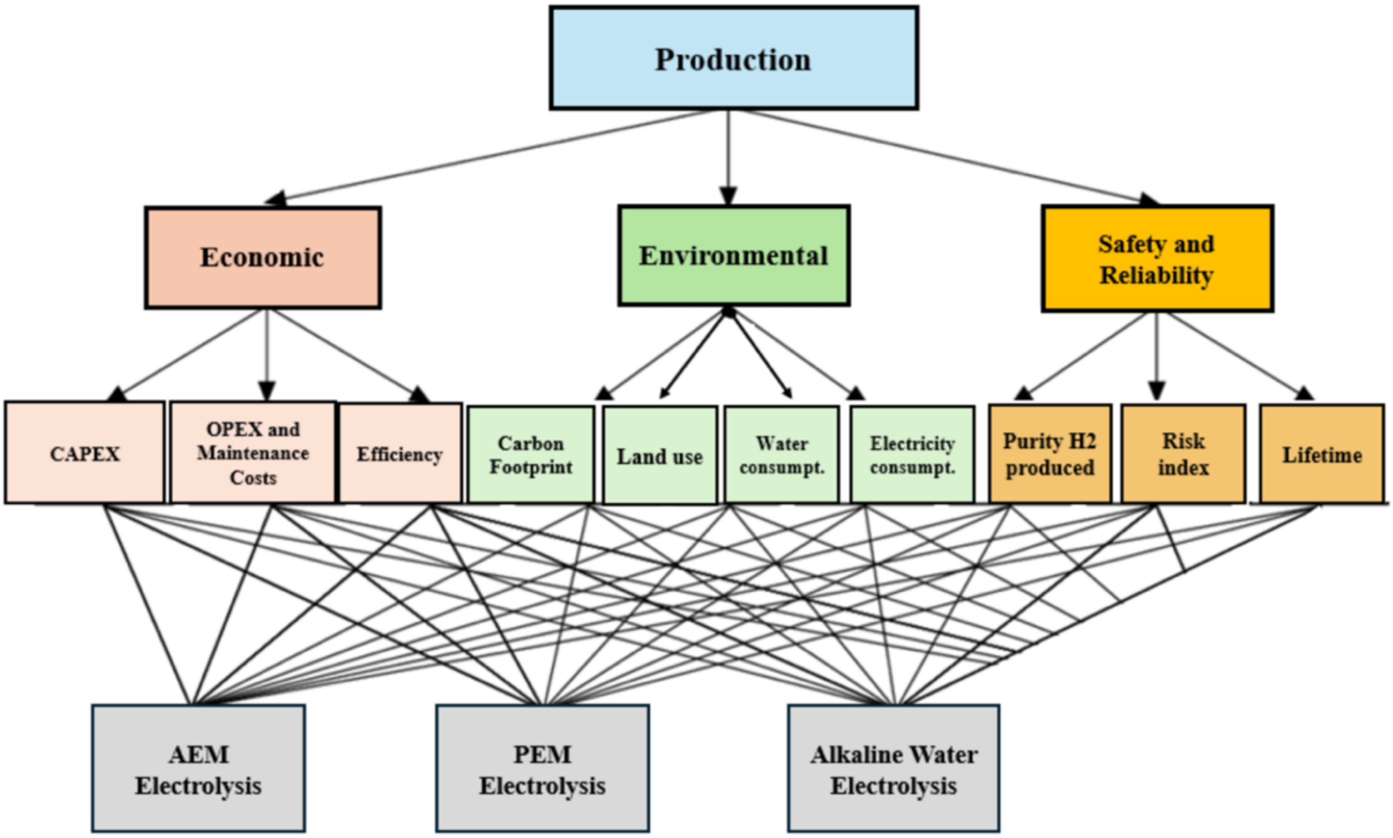


Figure 4: AHP hierarchical schematic for hydrogen production criteria- Kuwait

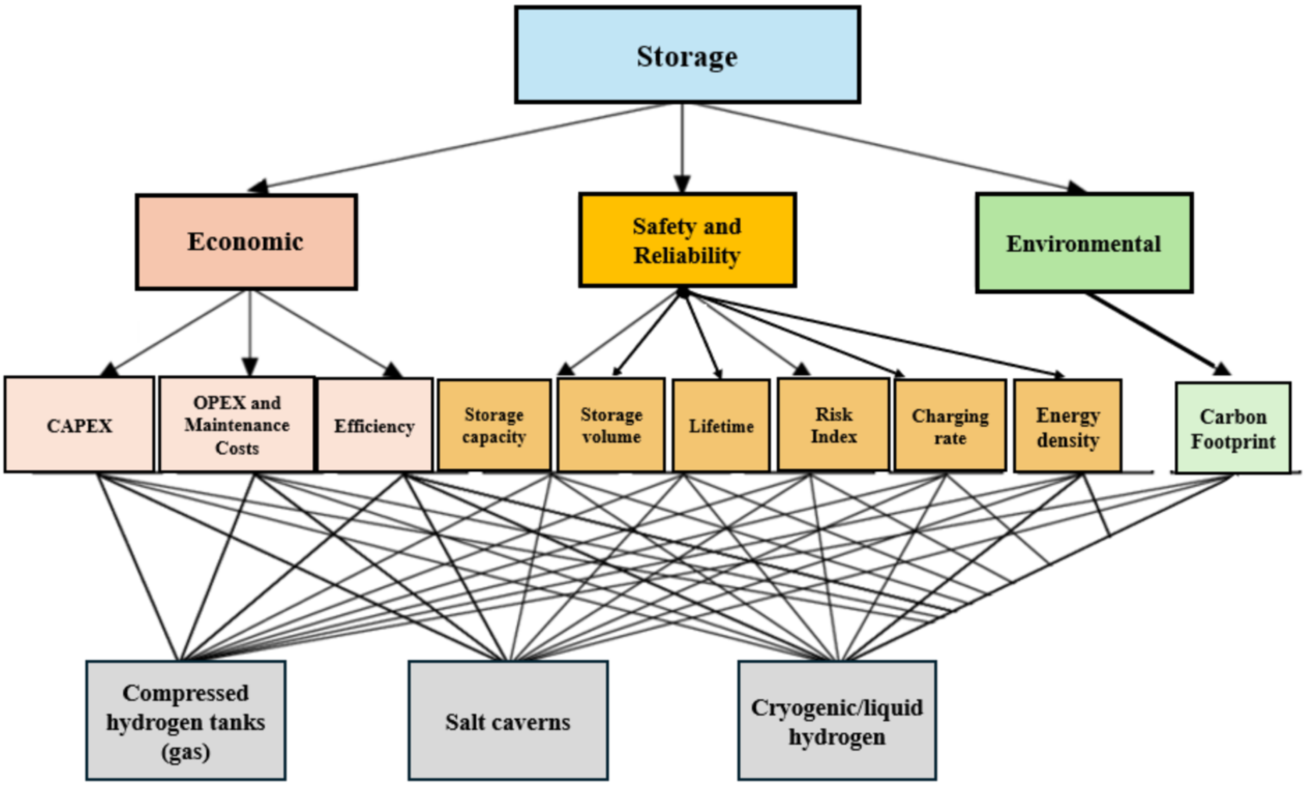


Figure 5: AHP hierarchical schematic for hydrogen storage criteria- Kuwait

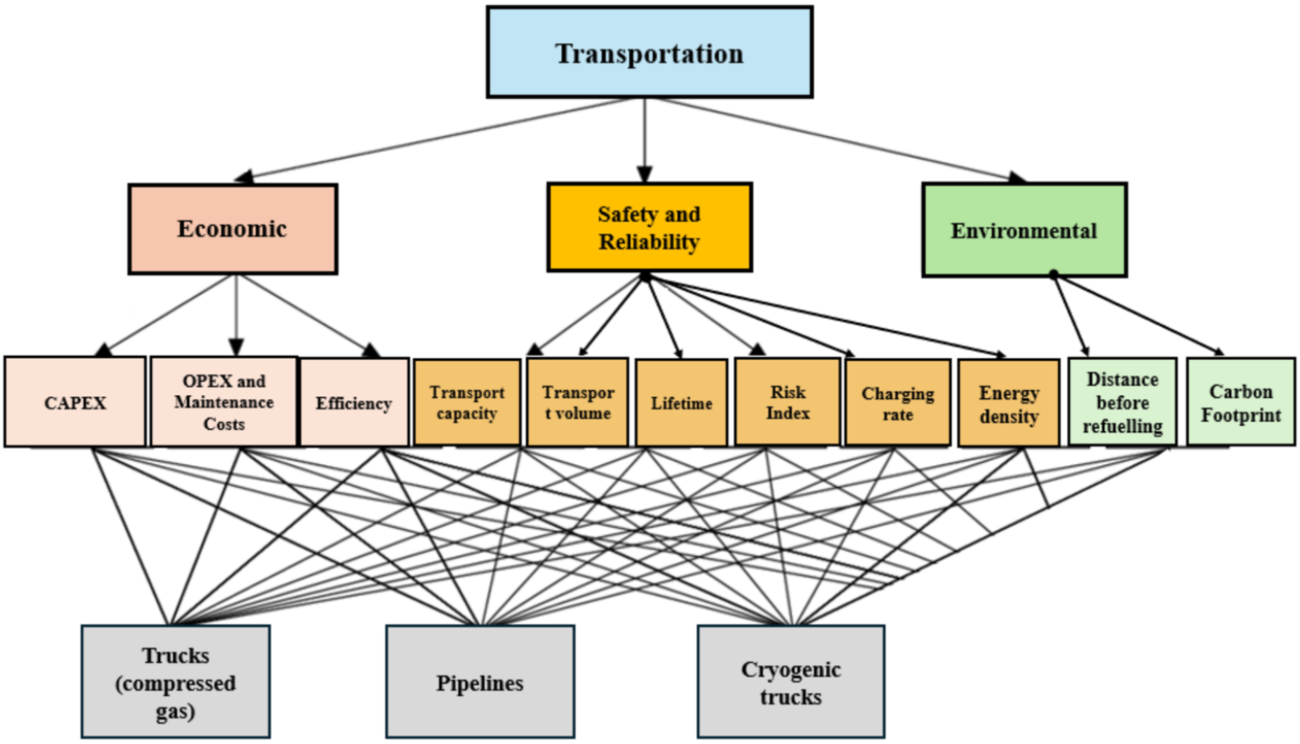


Figure 6: AHP hierarchical schematic for hydrogen transportation criteria- Kuwait

The same criteria are analysed across production, storage and transportation for the Kuwait and Saudi Arabia case studies. However, in the subsequent Saudi Arabia case study, production capacity is added as an explicit evaluation criterion, but is emitted from the Kuwait case. This choice reflects a deliberate methodological distinction based on the relative influence of capacity constraints on system performance. In the Kuwait case study, production capacity is implicitly accounted for within the optimisation framework through demand satisfaction constraints, ensuring that all selected technologies are capable of meeting the specified demand levels. Under these conditions, capacity does not act as a primary differentiating factor between technologies, and its explicit inclusion as a separate criterion would introduce redundancy and potential double counting within the evaluation. In contrast, the Saudi Arabia case study considers a broader system context in which demand levels are substantially higher and infrastructure deployment is scaled accordingly. Under these conditions, variations in production capacity across technologies become a critical determinant of system feasibility, scalability, and long-term performance. The explicit inclusion of production capacity therefore enables the model to distinguish between technologies based on their ability to operate effectively under large-scale deployment conditions, where capacity limitations may directly influence investment decisions, infrastructure expansion, and overall system efficiency across time periods. This context-specific treatment of production capacity ensures that the criteria set remains both non-redundant and representative of the dominant system constraints in each case study, thereby enhancing the robustness and interpretability of the optimisation results.

4.2.1 Kuwait Results 1 - No-Priority MILP

In the no-priority MILP scenario, all evaluation criteria are assigned equal weights to ensure an unbiased assessment across competing objectives. For hydrogen production and storage, where $N = 10$ (i.e. 10 criteria are considered), each criterion is assigned a uniform weighting of $w_i = 0.1$, such that $w_i = 0.1 \ \forall i \in \{1, \dots, 10\}$. In the case of transportation, where $N = 11$, each criterion is assigned an equal weighting of $w_i = \frac{1}{11}$, such that $w_i = \frac{1}{11} \ \forall i \in \{1, \dots, 11\}$. This uniform weighting structure eliminates preferential bias across criteria and enabling the identification of Pareto-optimal solutions across the three objectives and ensures that $\sum_{i=1}^{N} w_i = 1$. The resulting optimisation outcomes are presented in Figures 7–9 for the low, medium and high demand scenarios, respectively, while Table X summarises the corresponding performance scores and rankings for each hydrogen production, storage, and transportation technology.

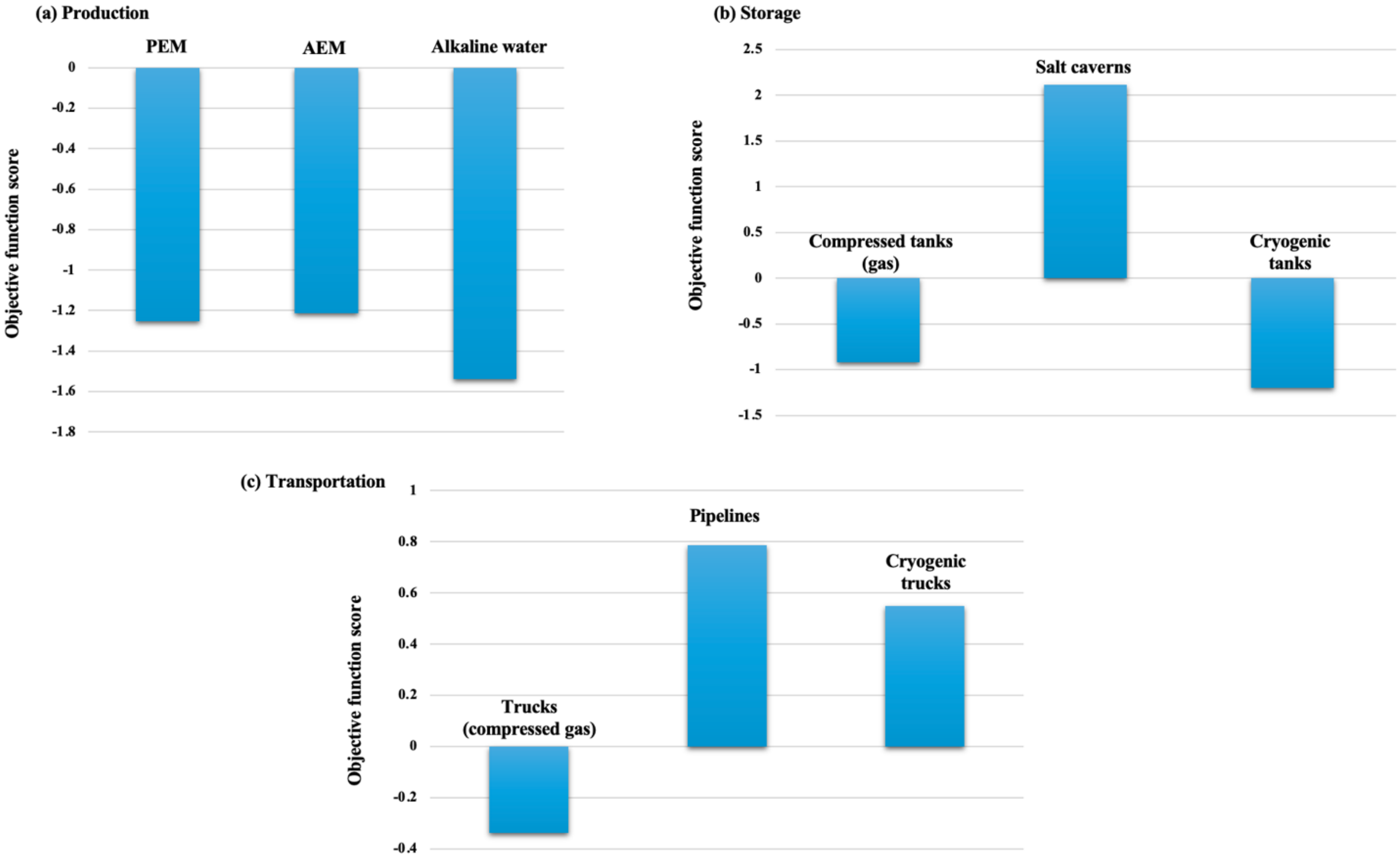


Figure 7: No-priority MILP results- low demand scenario, Kuwait

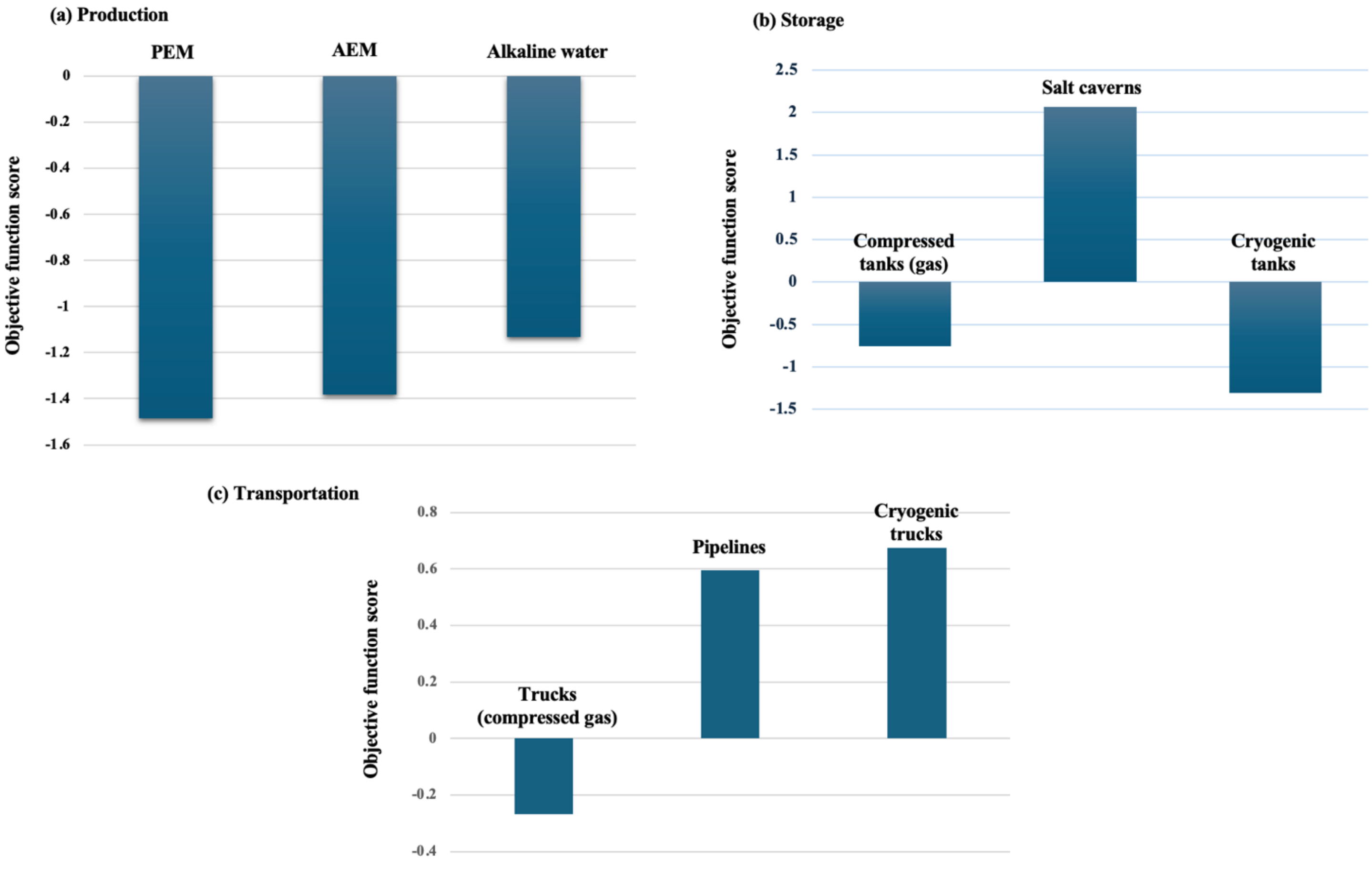


Figure 8: No-priority MILP results- medium demand scenario, Kuwait

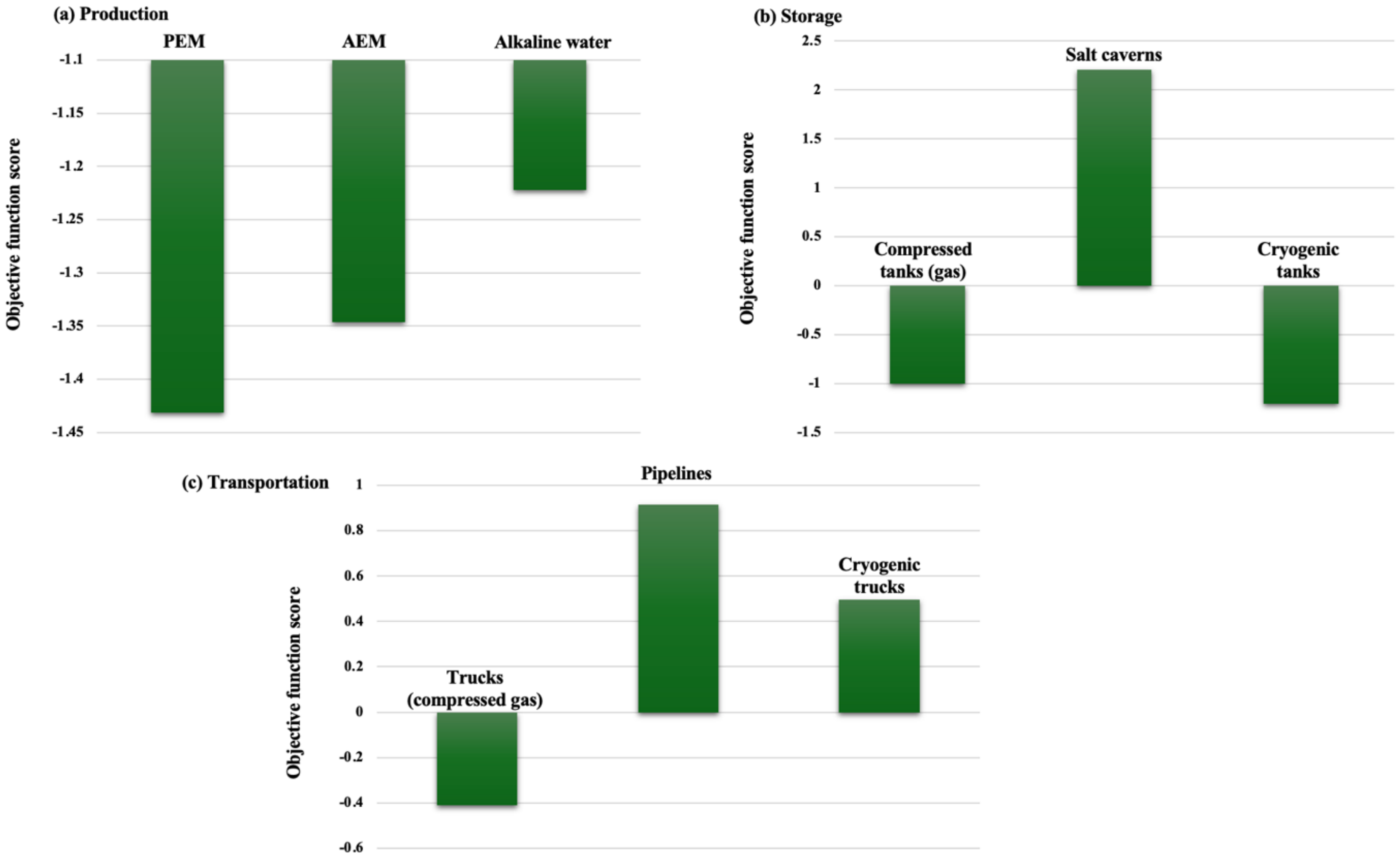


Figure 9: No-priority MILP results- high demand scenario, Kuwait

Table 9: No-priority MILP scores and rankings across low, medium, and high demand scenarios. Scores rounded to two decimal places. Rank 1 denotes optimal technology within each category. Rank colours: green = optimal (1), amber = second (2), red = lowest (3).

	Low Demand		**Medium Demand**		**High Demand**	
Technology	**Score**	**Rank**	**Score**	**Rank**	**Score**	**Rank**
Production						
PEM Electrolysis	-1.48	3	-1.25	2	-1.43	3
AEM Electrolysis	-1.38	2	**-1.21**	**1**	-1.35	2
Alkaline Water Electrolysis	**-1.13**	**1**	-1.54	3	**-1.22**	**1**
Storage						
Compressed Gas Tanks	-0.76	2	-0.93	2	-0.99	2
Salt Caverns	**2.07**	**1**	**2.12**	**1**	**2.21**	**1**
Cryogenic Tanks	-1.31	3	-1.20	3	-1.21	3
Transportation						
Compressed Gas Trucks	-0.27	3	-0.34	3	-0.41	3
Pipelines	0.59	2	**0.79**	**1**	**0.91**	**1**
Cryogenic Trucks	**0.67**	**1**	0.55	2	0.50	2

Across the evaluated demand scenarios, the optimal technology selection varies primarily within the production and transportation stages, while storage remains consistently stable. In the low-demand scenario, alkaline water electrolysis emerges as the optimal hydrogen production technology and cryogenic trucks emerge as the preferred transportation mode. In the medium-demand scenario, AEM electrolysis becomes the highest-ranked production option, while pipelines become the optimal transportation solution. In the high-demand scenario, alkaline water electrolysis again ranks as the optimal production technology, and pipelines remain the preferred transport option. Across all three demand cases, salt caverns consistently emerge as the optimal storage solution.

These results indicate that hydrogen production technologies are the most sensitive to variations in demand. Although alkaline water electrolysis is optimal in two out of the three scenarios, suggesting strong overall performance, the shift observed in the medium-demand case highlights the dependence of electrolyser performance on operating conditions. Electrolysers have optimal efficiency ranges, typically ranging between 60-87% that are linked to their capacity utilisation. AEM electrolysers have an efficiency of about 79%, while PEM can reach as high as 86%. In the case of low demand, running an electrolyser below its capacity can decrease its efficiency, lowering the overall score of the electrolyser. Conversely, in a high demand scenario, running the electrolyser at full capacity can also impact efficiency and subsequently, operational and maintenance costs. It is important to note however, the magnitude of the score differences across scenarios. For storage technologies, salt caverns consistently outperform alternatives by a substantial margin, with score differences of 2.83 in the low-demand case, 3.05 in the medium-demand case, and 3.2 in the high-demand case. This indicates strong robustness and clear dominance of salt cavern storage across all demand conditions. For production technologies, the differences between electrolyser options remain relatively small across all scenarios. The gap between the highest- and lowest-ranked production technologies is 0.35 in the low-demand case, 0.29 in the medium-demand case, and 0.21 in the high-demand case. These differences, all below 0.5, indicate that no single electrolyser technology is clearly dominant under a no-priority weighting structure. Instead, the alternatives are closely parallel in performance, meaning that relatively small changes in input assumptions such as electricity cost, efficiency, or CAPEX could shift the preferred option, as evidenced by the medium-demand scenario.

For transportation, the observed results indicate a lower sensitivity to demand variations compared to production, but a higher sensitivity than storage. In the low-demand scenario, cryogenic trucks emerge as the optimal transport mode, outperforming the third-ranked option (compressed gas trucks) by 0.94. However, the difference between cryogenic trucks and pipelines is only 0.08, which is relatively marginal. This outcome is predominantly driven by the lower upfront capital investment associated with cryogenic truck-based systems compared to the establishment of a pipeline network. In the medium and high-demand scenarios, pipelines become the preferred transportation option. In the medium-demand case, pipelines outperform cryogenic trucks by 0.24, and this margin increases to 0.41 in the high-demand scenario. Despite their higher initial capital costs, the improved performance of pipelines at higher demand levels indicates the presence of economies of scale, whereby the system becomes increasingly cost-effective under sustained and large-volume hydrogen transport requirements. Although, as with the production technologies, the relatively small differences in scores indicate that transportation remains sensitive to demand assumptions, pipelines are nevertheless likely to represent the most practically suitable long-term transport option. This is primarily due to system-level compatibility, as both production and storage pathways favour hydrogen in gaseous form, making pipeline infrastructure more aligned with the overall supply chain configuration than liquid-based alternatives. Finally, carbon footprint and risk indices were included as evaluation criteria; however, these parameters remained constant across all demand scenarios for each transport option. As a result, in this case, they were not likely to influence changes in ranking between scenarios and therefore have limited impact on the observed sensitivity patterns.

4.2.2 Kuwait Results 2- No-Priority TOPSIS

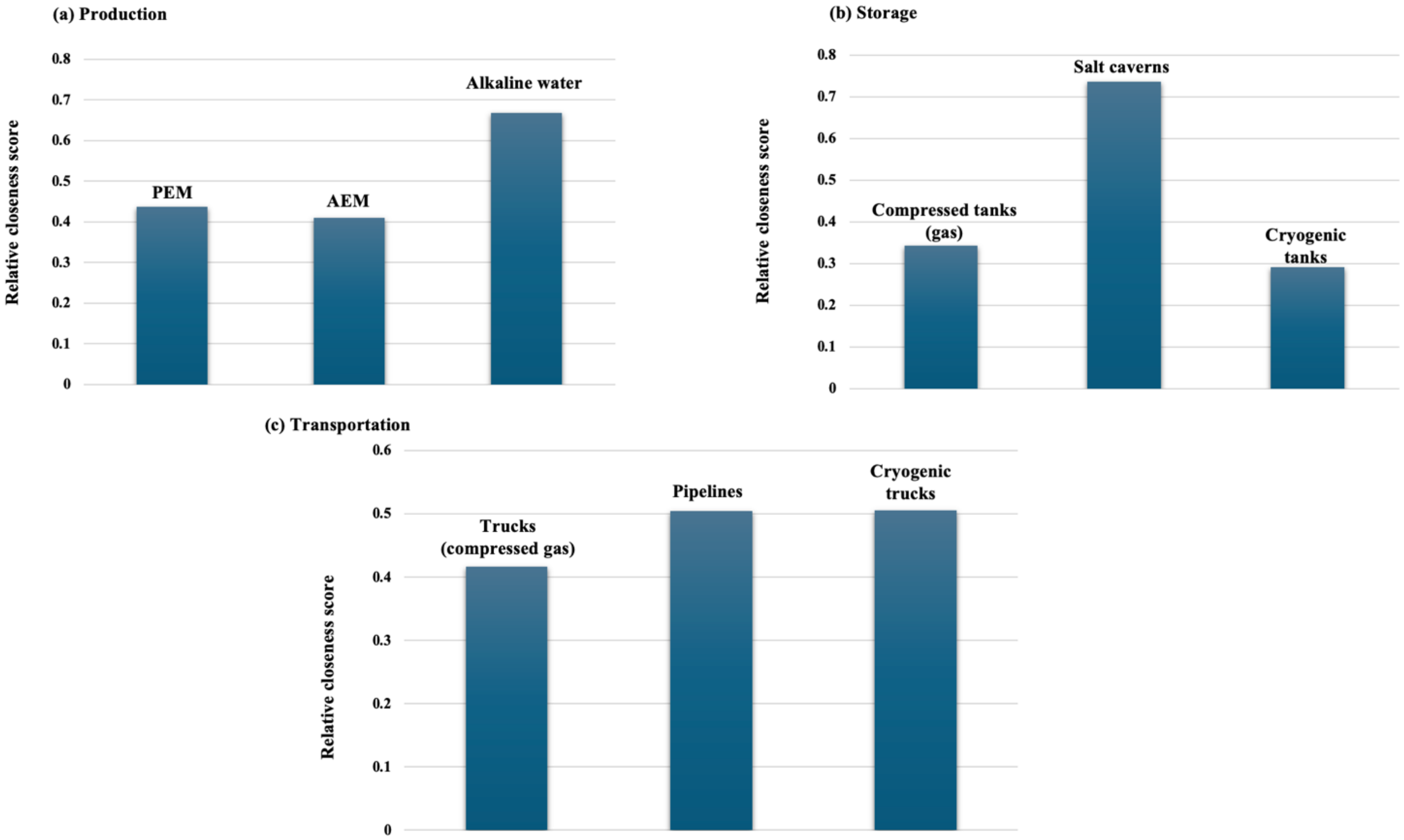


Figure 10: No-priority TOPSIS results- low demand scenario, Kuwait

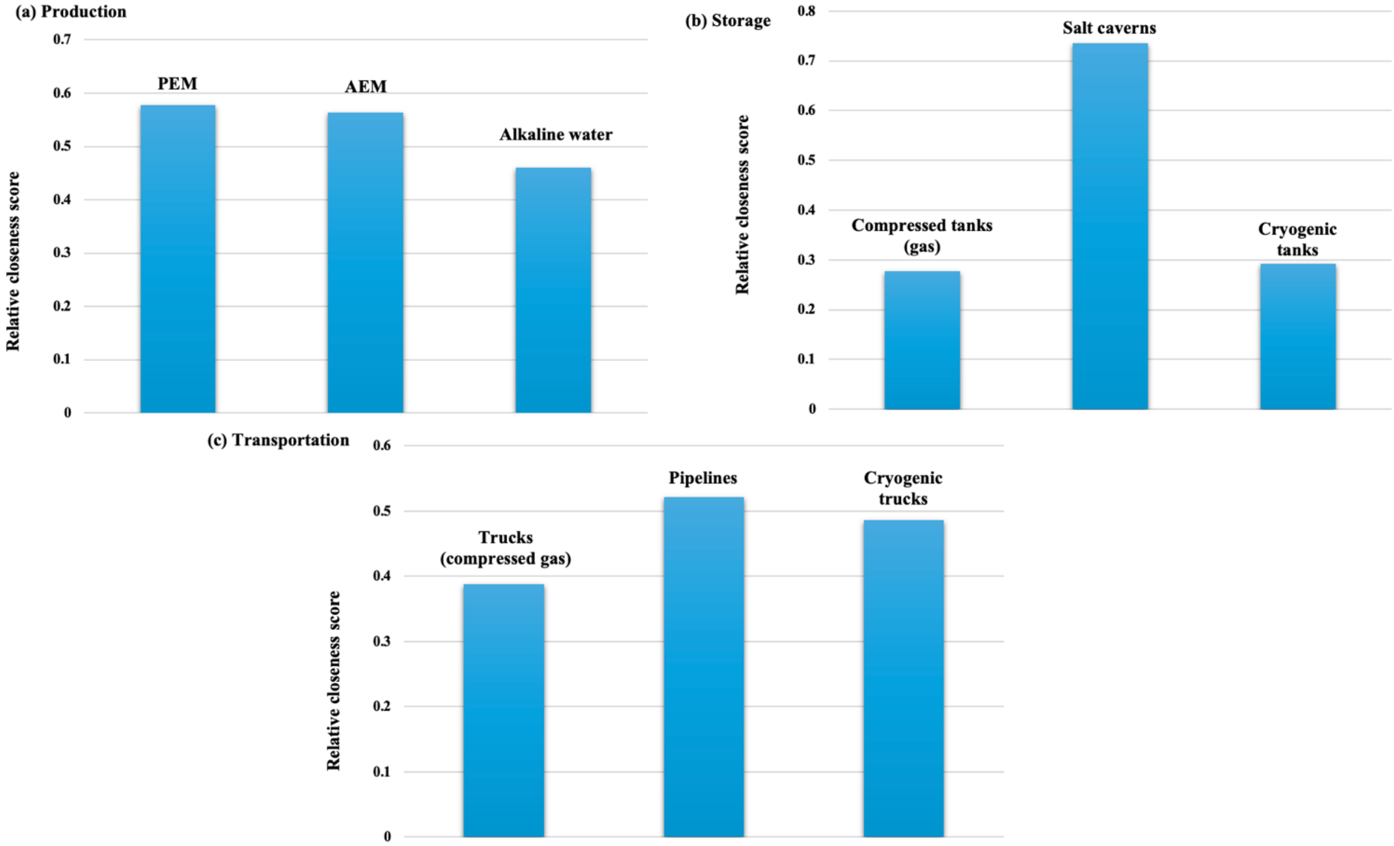


Figure 11: No-priority TOPSIS results- medium demand scenario, Kuwait

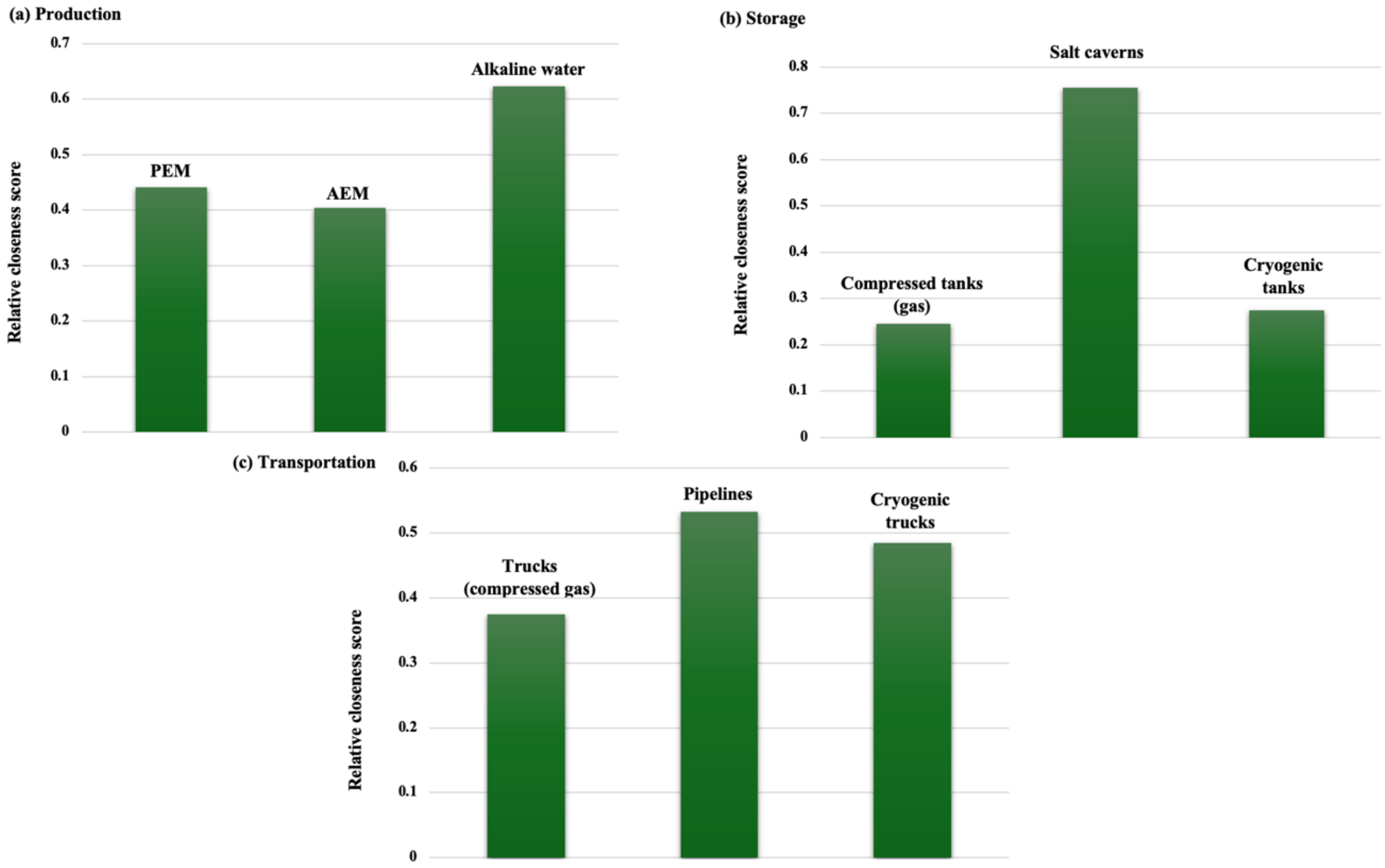


Figure 12: No-priority TOPSIS results- high demand scenario, Kuwait

Table 10: No-priority TOPSIS scores and rankings across low, medium, and high demand scenarios. Scores rounded to two decimal places. Rank 1 denotes optimal technology within each category. Rank colours: green = optimal (1), amber = second (2), red = lowest (3).

	Low Demand		**Medium Demand**		**High Demand**	
Technology	**Score**	**Rank**	**Score**	**Rank**	**Score**	**Rank**
Production						
PEM Electrolysis	0.44	2	**0.58**	**1**	0.44	2
AEM Electrolysis	0.41	3	0.56	2	0.40	3
Alkaline Water Electrolysis	**0.67**	**1**	0.46	3	**0.62**	**1**
Storage						
Compressed Gas Tanks	0.34	2	0.28	3	0.25	3
Salt Caverns	**0.74**	**1**	**0.73**	**1**	**0.76**	**1**
Cryogenic Tanks	0.29	3	0.29	2	0.27	2
Transportation						
Compressed Gas Trucks	0.42	3	0.39	3	0.37	3
Pipelines	0.50	2	**0.52**	**1**	**0.53**	**1**
Cryogenic Trucks	**0.51**	**1**	0.49	2	0.48	2

The results obtained from the no-priority TOPSIS analysis (Figures 10–12) are largely aligned with those from the no-priority MILP in terms of the identified optimal configurations for hydrogen production, storage, and transportation. For production, alkaline water electrolysis is again ranked as the optimal option in both the low and high-demand scenarios, consistent with the MILP outcomes. The key distinction between the two methods lies in how the results are evaluated. TOPSIS ranks alternatives based on their relative proximity to an ideal solution and therefore does not generate negative values. In contrast, the MILP formulation determines optimality based on the least negative objective function value due to its weighted-sum structure. This difference in methodological approach helps explain why PEM electrolysis is identified as the optimal technology in the medium-demand scenario under TOPSIS. In this case, PEM performs closer to the ideal solution across one or more criteria, which results in a higher overall ranking. However, it is important to consider the magnitude of the score differences. As observed in the MILP results, the variation between electrolyser scores remains small: 0.26 in the low-demand scenario, 0.12 in the medium-demand scenario, and 0.22 in the high-demand scenario. These consistently narrow margins further confirm that electrolyser selection is highly sensitive to demand and that no single technology clearly dominates under a no-priority weighting structure.

For storage, salt caverns remain the highest-ranked option across all demand scenarios, indicating a stable and robust performance under the conditions considered for Kuwait. While the optimal choice remains unchanged, some variation is observed in the ranking of the second- and third-best storage options compared to the MILP results. This can be attributed to the different optimisation mechanisms employed by TOPSIS and MILP rather than any significant change in underlying performance.

For transportation, the rankings are identical to those obtained from the MILP analysis across all demand scenarios. Cryogenic trucks are preferred in the low-demand case, which can be linked to their lower initial capital requirements. As demand increases, pipelines become the optimal option, reflecting economies of scale associated with higher transport volumes and lower unit costs despite higher upfront investment.

From a decision-making perspective, the consistency between the MILP and TOPSIS results suggests a clear and predictable transition point at which pipelines begin to outperform cryogenic trucks as demand increases. This provides a reliable basis for infrastructure planning in relation to projected demand growth. More broadly, the agreement between the optimal configurations identified by both approaches reduces uncertainty in system design, as similar outcomes are obtained under different modelling frameworks. This consistency strengthens confidence in the results and supports their application in practical infrastructure planning.

4.2.3 Kuwait Results 3- Sensitivity Analysis

To evaluate the effect of individual criterion weight variations on the final rankings within the no-priority TOPSIS framework, a sensitivity analysis was performed to examine ranking stability and identify the most influential parameters. While the AHP framework introduces structured weighting based on stakeholder preferences, it remains static in a single-period formulation and does not explicitly test the impact of incremental weight changes on system outcomes. Therefore, the sensitivity analysis was implemented within the no-priority TOPSIS model, where all criteria are initially assigned equal importance, allowing the isolated effect of weight variation to be assessed.

For each production, storage, and transportation category, a single criterion was selected, and its weight was varied between 0 and 1. For each tested value w_i, the remaining weight $(1 - w_i)$ was distributed equally across all other criteria in the same category. For example, in hydrogen production with 10 criteria, if CAPEX was assigned $w_i = 0.3$, then each of the remaining 9 criteria received a weight of $(1 - 0.3)/9$. The same approach was applied to transportation, where 11 criteria were considered; if one criterion was set to $w_i = 0.4$ the remaining 10 criteria each received $(1 - 0.4)/10$.

The full sensitivity results and corresponding weight matrices for production, storage, and transportation are provided in the Appendix, while the effects of weight variation are illustrated in Figures 13–15. The analysis focuses on the high-demand scenario, which serves as a stress test representing peak system operation. Under these conditions, system constraints are most pronounced, and the supply chain is more responsive to variations in criterion weighting.

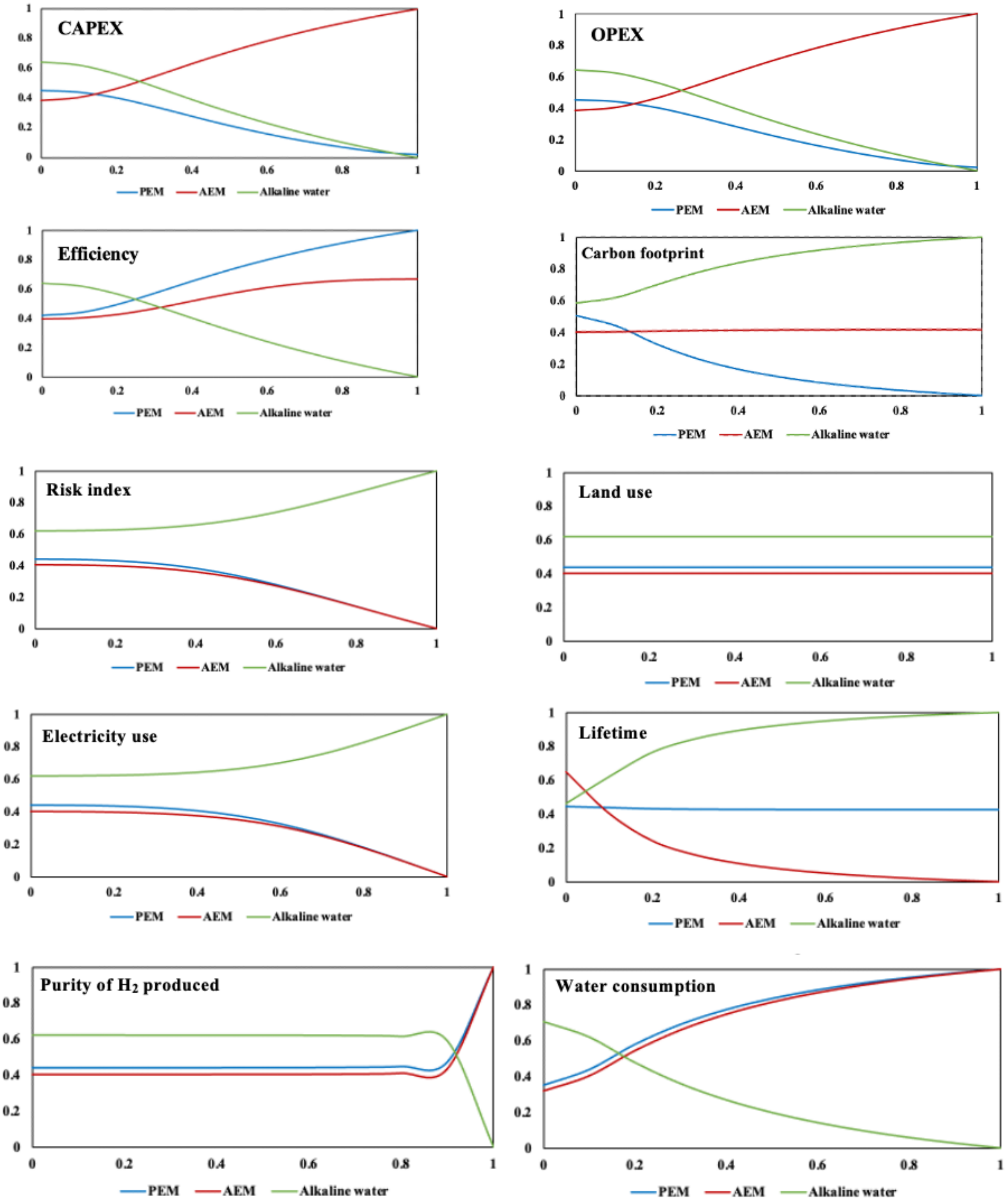


Figure 13: Sensitivity analysis- hydrogen production criteria, Kuwait

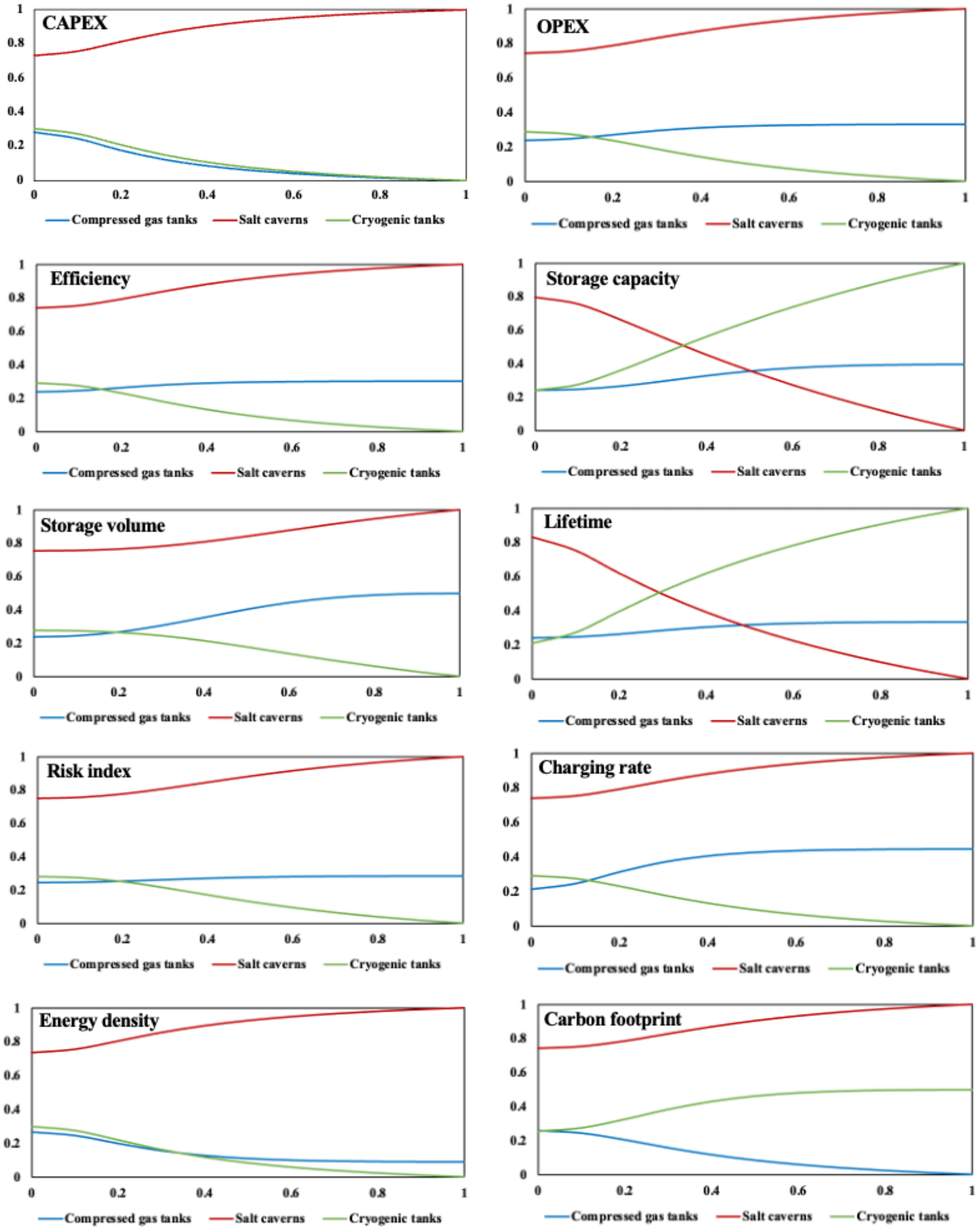


Figure 14: Sensitivity analysis- hydrogen storage criteria, Kuwait

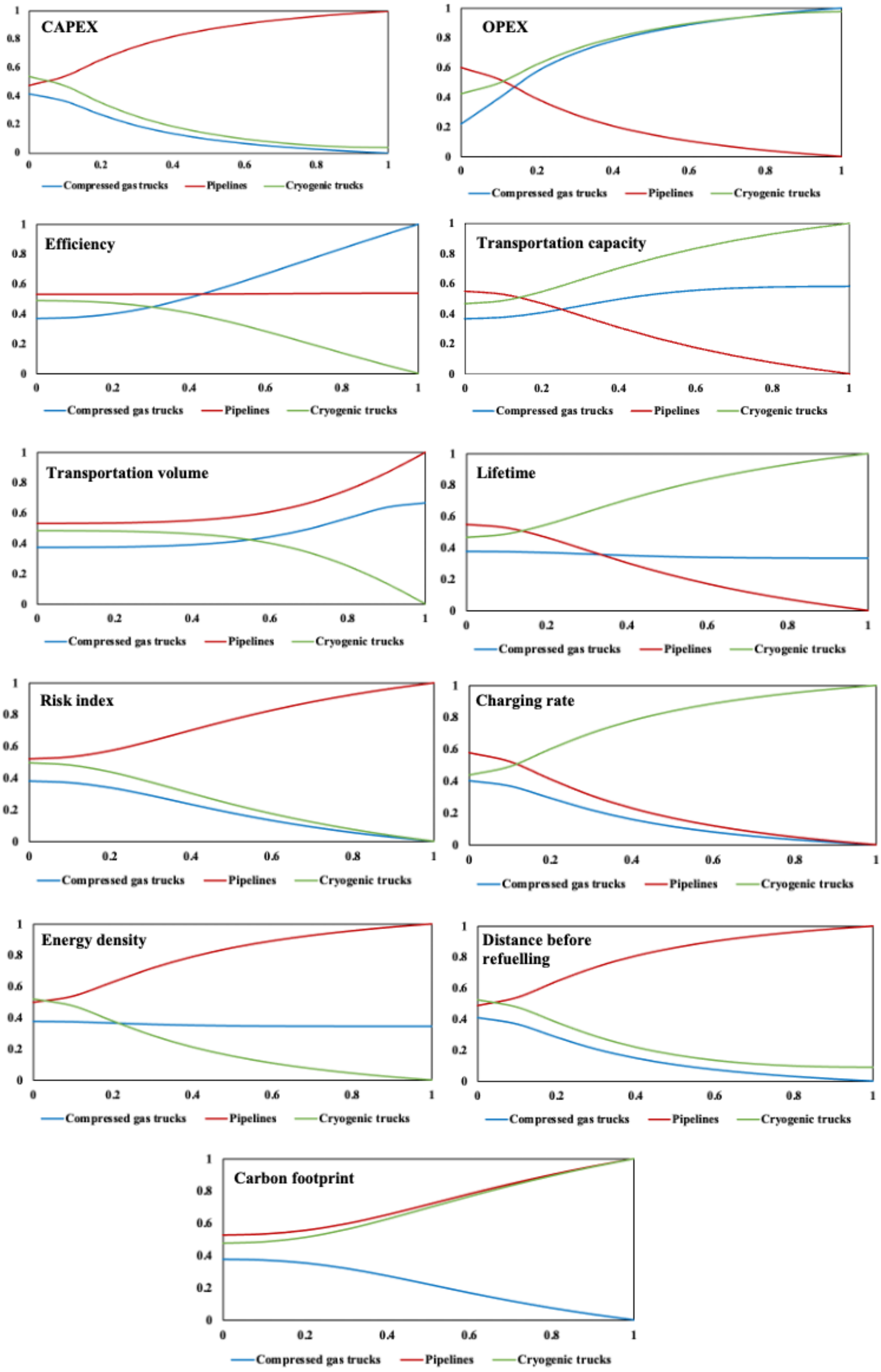


Figure 15: Sensitivity analysis- hydrogen transportation criteria, Kuwait

Although alkaline water electrolysis is identified as the optimal production option under equal weighting, the sensitivity analysis highlights several underlying behaviours that limit its robustness when decision priorities shift. A consistent trend is the improved performance of AEM electrolysis as individual criteria are increasingly emphasised. This indicates that while alkaline water electrolysis performs well as a balanced option, AEM becomes more competitive when specific performance factors are prioritised. A key relationship is observed between electricity consumption and efficiency. While alkaline electrolysis shows the lowest electricity consumption in absolute terms, it exhibits the largest performance decline when electricity-related criteria are assigned higher weight. This reflects the dependence of electricity use on efficiency, particularly at scale. As previously established, PEM electrolysis can reach efficiencies of up to 86%, AEM operates at approximately 79%, and alkaline systems around 65%. At higher production levels, lower efficiency leads to increased electricity consumption per unit of hydrogen, making alkaline systems more sensitive under electricity-weighted conditions despite lower baseline usage. A further observation concerns the link between efficiency and electricity price sensitivity. AEM and PEM, although more efficient, show greater sensitivity to electricity price fluctuations. This suggests that their cost structures are more heavily dependent on electricity, increasing exposure to operational cost variability. In contrast, alkaline systems are more influenced by fixed CAPEX components, which reduces their sensitivity to electricity price changes. As such, higher efficiency does not directly correspond to lower cost sensitivity; rather, the outcome depends on how electricity costs are weighted within the decision framework. Carbon footprint and risk on the other hand have minimal influence on production rankings, indicating that the primary trade-offs are driven by cost-energy-efficiency interactions rather than environmental or safety considerations.

For storage, salt caverns consistently rank highest across all weighting scenarios, confirming their robustness irrespective of preference structure. The main sensitivity effects are observed in cryogenic tanks, which show strong dependence on energy density. Their performance improves significantly when this criterion is prioritised, reflecting a reliance on volumetric efficiency rather than cost performance. A similar trend is observed for storage capacity, where cryogenic tanks exhibit the largest improvement in ranking when capacity is weighted more heavily, surpassing compressed gas storage and narrowing the gap with salt caverns. This indicates that cryogenic storage becomes more competitive when spatial efficiency is prioritised. However, under broader weighting conditions, higher costs reduce their overall ranking. Consequently, cryogenic tanks are more suitable in applications where space is constrained, such as urban environments, where storage density outweighs cost considerations.

For transportation, the results clearly demonstrate economies of scale associated with pipelines. Pipeline performance increases significantly with higher CAPEX weighting (from 0.479 at zero weighting to 1.0 at full weighting), indicating that pipelines are preferred when long-term investment performance is prioritised over initial cost. Cryogenic trucks remain competitive under low CAPEX weighting due to lower upfront costs, but their ranking declines as CAPEX weighting increases. Similar behaviour is observed for OPEX and efficiency, where cryogenic trucks perform well at lower weightings but are overtaken by pipelines as system scale increases. This confirms that their advantage lies in operational flexibility rather than large-scale efficiency. For transport capacity and volume, cryogenic trucks perform better when these criteria are given lower importance, reflecting suitability for smaller-scale, flexible distribution. As weighting increases, pipelines become dominant, reinforcing their suitability for high-volume transport. When charging rate and energy density are prioritised, cryogenic trucks again perform strongly, indicating their relevance in applications requiring rapid delivery and high energy transfer. As with production and storage, carbon footprint and risk have negligible impact on transportation rankings, confirming that system behaviour is primarily governed by cost-efficiency-capacity trade-offs.

Overall, the sensitivity analysis provides clear insights for demand-responsive infrastructure planning. CAPEX has limited influence at low demand levels but becomes increasingly important as demand increases. This suggests that early-stage hydrogen systems are more likely to favour lower-CAPEX options such as cryogenic tanks and trucks due to their flexibility and lower initial investment requirements. As demand stabilises and increases, higher-CAPEX but more efficient infrastructure, such as salt caverns and pipelines, becomes more economically viable. Salt caverns consistently demonstrate strong performance, although their applicability depends on geological availability. Cryogenic tanks, while more expensive, may be preferable in space-constrained environments due to their performance under energy density and capacity-focused conditions. Pipelines emerge as the dominant transport solution in medium- to high-demand scenarios due to economies of scale. In contrast, cryogenic trucks are better suited to low-demand conditions, offering flexibility and lower upfront costs. This supports a staged infrastructure development approach, where truck-based systems are deployed initially, followed by gradual investment in pipeline networks as demand increases. A hybrid system combining both transport modes may provide an effective balance between flexibility and long-term cost efficiency under variable demand conditions.

4.2.4 Kuwait Results 4- AHP-TOPSIS Hybrid

An AHP analysis was implemented to provide a structured and systematic basis for assigning weights to the evaluation criteria. In the no-priority scenarios, the objective was to design and assess a hydrogen supply chain using two complementary approaches: a model that optimises the aggregated criteria score (MILP), and a model that ranks alternatives based on proximity to an ideal solution (TOPSIS). In both approaches, all criteria were initially treated as equally important, which may not reflect the differentiated priorities of stakeholders in practical applications. As outlined previously, the AHP flowcharts and corresponding criteria are shown in Figures 4–6, while the associated pairwise comparison matrices are provided in the Appendix. The criteria weightings derived from the AHP analysis were first propagated through the TOPSIS framework, allowing the ranking process to explicitly reflect stakeholder-informed preferences via distance-to-ideal evaluation. The resulting prioritised weight structure was then integrated into the MILP formulation, replacing the uniform weighting assumption with AHP-informed coefficients within the objective function. This sequential AHP-TOPSIS-MILP integration introduces a preference-consistent optimisation layer, enabling direct comparison between equal-weight and prioritised scenarios. As such, it allows assessment of whether the solutions identified as optimal under a purely robustness-driven MILP framework remain stable when subjected to structured, stakeholder-derived weighting schemes, thereby strengthening the overall validity and interpretability of the results.

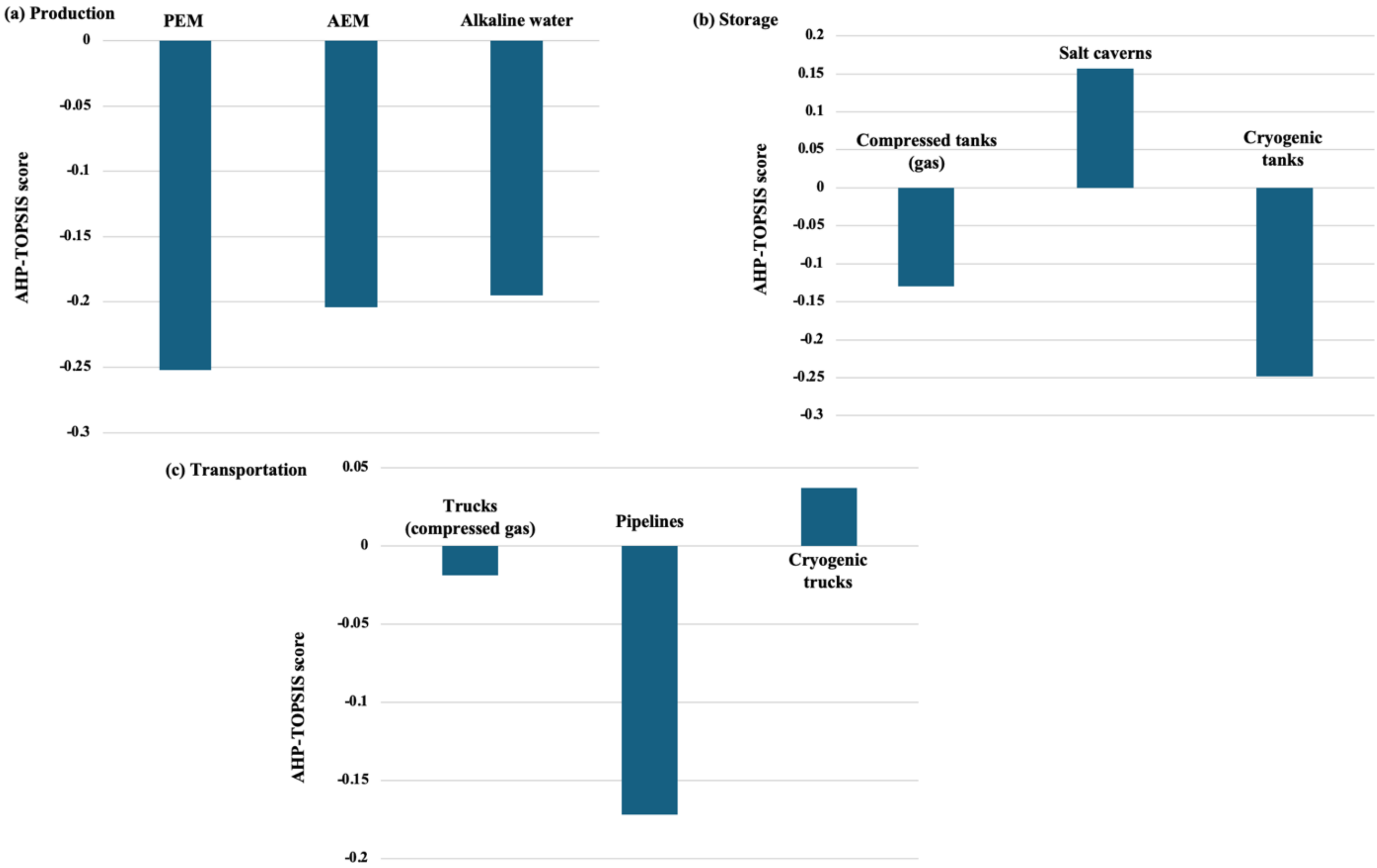


Figure 16: AHP-TOPSIS hybrid results- low demand scenario, Kuwait

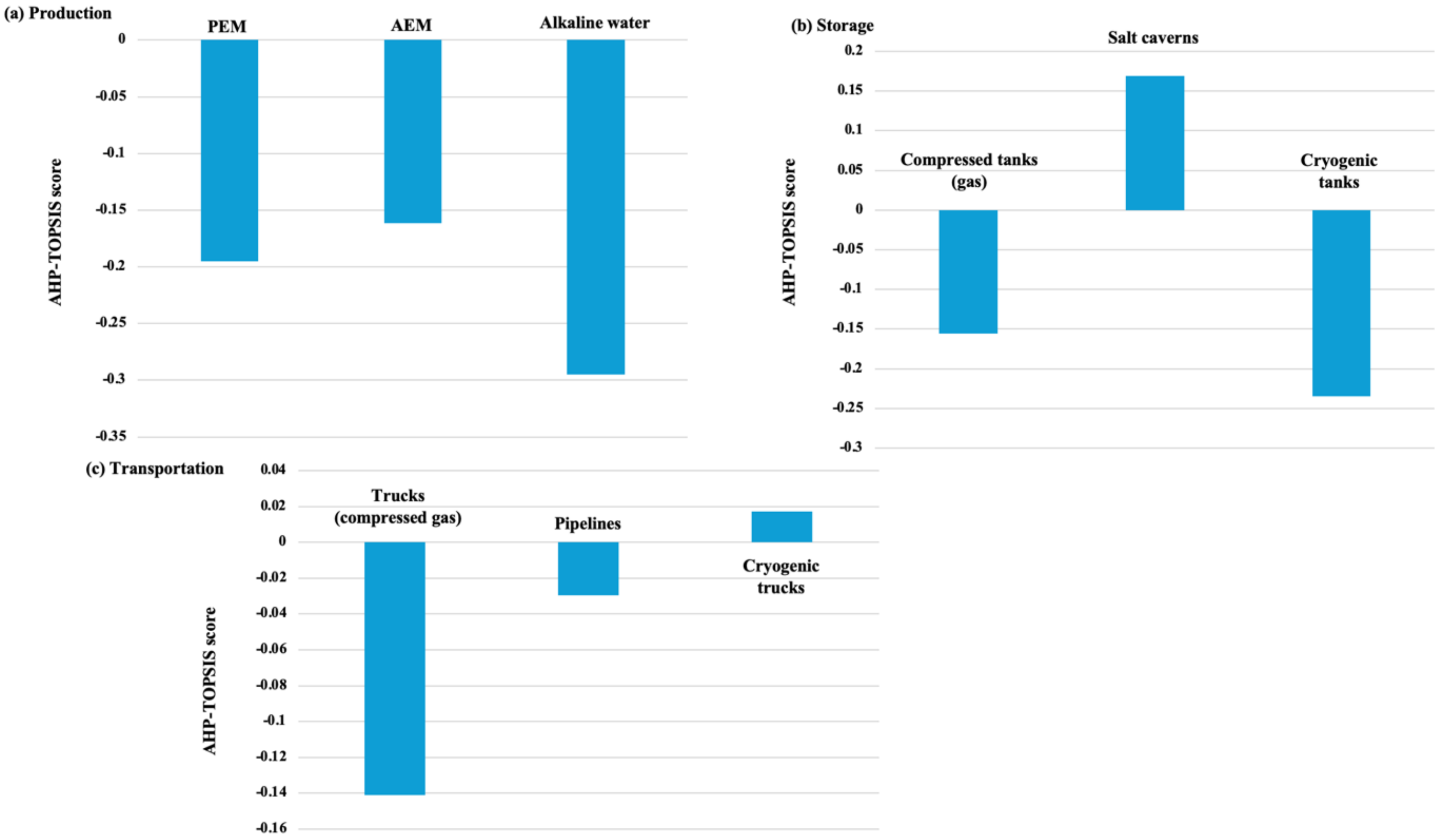


Figure 17: AHP-TOPSIS hybrid results- medium demand scenario, Kuwait

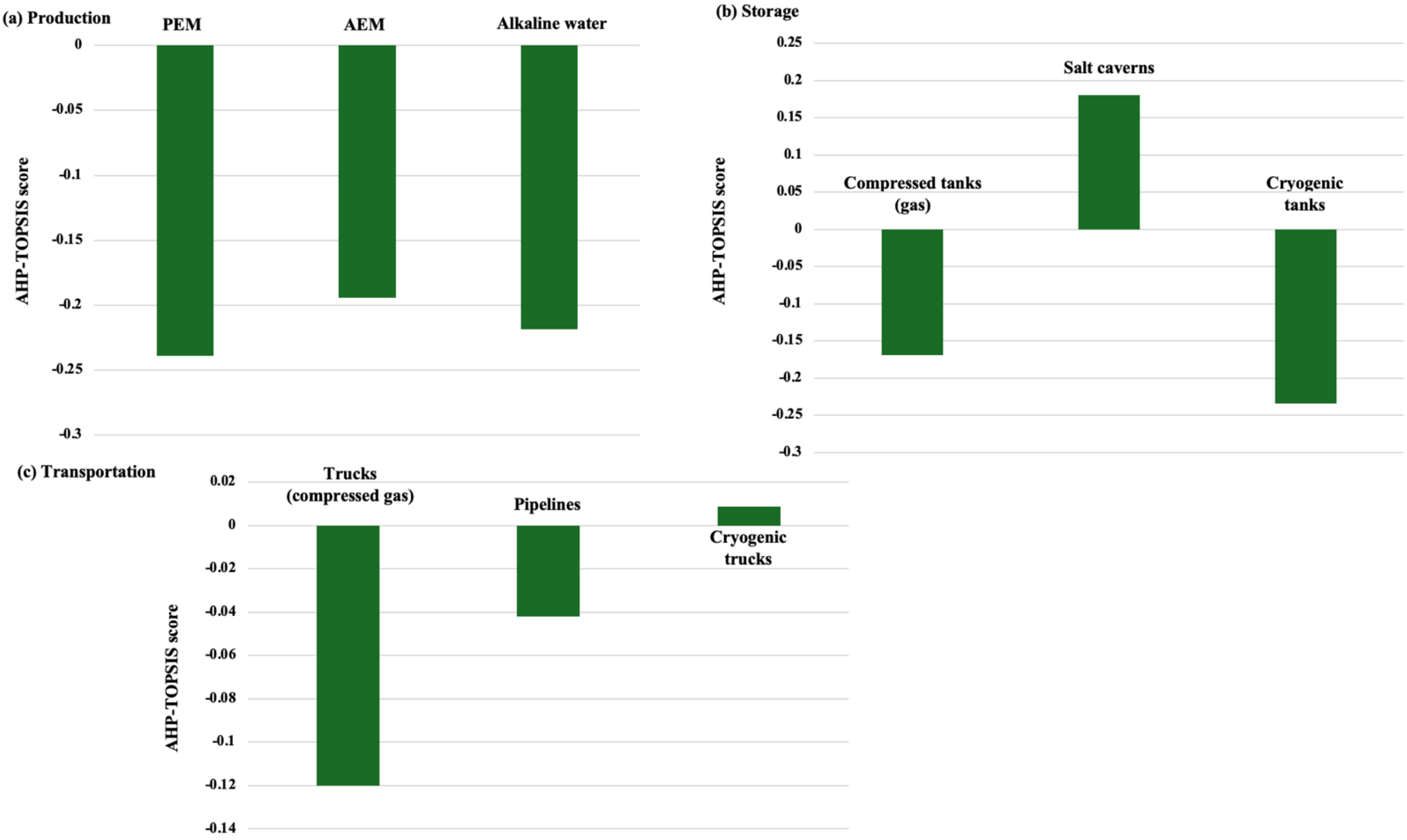


Figure 18: AHP-TOPSIS hybrid results- high demand scenario, Kuwait

Table 11: AHP-TOPSIS hybrid scores and rankings across low, medium, and high demand scenarios. Scores rounded to two decimal places. Rank 1 denotes optimal technology within each category. Rank colours: green = optimal (1), amber = second (2), red = lowest (3).

	Low Demand		Medium Demand		High Demand	
Technology	**Score**	**Rank**	**Score**	**Rank**	**Score**	**Rank**
Production						
PEM Electrolysis	-0.25	3	-0.19	2	-0.24	3
AEM Electrolysis	-0.20	2	**-0.16**	**1**	**-0.19**	**1**
Alkaline Water Electrolysis	**-0.19**	**1**	-0.29	3	-0.22	2
Storage						
Compressed Gas Tanks	-0.13	2	-0.16	2	-0.17	2
Salt Caverns	**0.16**	**1**	**0.17**	**1**	**0.18**	**1**
Cryogenic Tanks	-0.25	3	-0.23	3	-0.23	3
Transportation						
Compressed Gas Trucks	-0.02	2	-0.14	3	-0.12	3
Pipelines	-0.17	3	-0.03	2	-0.04	2
Cryogenic Trucks	**0.04**	**1**	**0.02**	**1**	**0.01**	**1**

When stakeholder-informed preferences are incorporated, the resulting optimal hydrogen supply chain configurations across demand scenarios remain largely consistent with the no-priority cases. In the low-demand scenario, the optimal configuration is unchanged, with alkaline water electrolysis, salt caverns, and cryogenic trucks again identified as the best-performing combination. This suggests that even when preferences are explicitly introduced through AHP-derived weightings, they remain broadly aligned with the technically optimal solutions obtained under equal weighting.

For hydrogen production, alkaline water electrolysis remains optimal under low demand, while AEM electrolysis becomes the highest-ranked option in both the medium and high-demand scenarios. Consistent with the previously discussed relationship between part-load operation and efficiency, an additional observation relates to the interaction between CAPEX and demand level. Although alkaline water electrolysis has a higher CAPEX than AEM, it still performs best in the low-demand case despite CAPEX being strongly prioritised. This indicates that at low demand, fixed capital cost alone is not the dominant driver of performance. Instead, cost behaviour is more strongly influenced by the relationship between electricity consumption, efficiency, and the actual hydrogen output. At low utilisation, AEM's higher efficiency does not translate into a large operational advantage because overall electricity consumption is relatively low. However, as demand increases, the benefit of higher efficiency becomes more pronounced due to larger production volumes and associated electricity use. Nonetheless, it is important to highlight that the score differences between the highest and lowest performing electrolysers remain very small: 0.06 in low demand, 0.10 in medium demand, and 0.05 in high demand. This confirms that all electrolyser technologies remain closely parallel in performance, reinforcing their high sensitivity to demand conditions. From a long-term perspective, this suggests that technologies performing well under medium to high-demand conditions may offer more stable outcomes as system scale increases and efficiency-related criteria become more influential.

For storage, salt caverns remain the highest-ranked option across all demand scenarios, confirming their robustness even under weighted stakeholder preferences. Compared to the no-priority case, however, the score separation between salt caverns and alternative storage methods is reduced, with differences of 0.41 (low), 0.40 (medium), and 0.41 (high). This reduction is driven by the fact that prioritised criteria amplify secondary performance aspects where alternative storage technologies perform relatively better. In particular, salt caverns have the lowest energy density among the storage options, allowing compressed gas and cryogenic storage systems to gain relative advantage when this criterion is weighted more heavily. This reduces their overall dominance in the aggregated scoring. In practical terms, this highlights an important trade-off. Salt caverns remain the most cost-effective solution for large-scale storage, but their feasibility is highly dependent on geological availability. In contrast, compressed gas and cryogenic storage systems, despite higher costs, offer greater flexibility in regions where suitable geological formations are not available. In the case of Kuwait, favourable geological conditions- such as depleted oil reservoirs and extensive flat land- generally support the use of salt caverns, reducing this constraint. Overall, salt caverns still perform best across economic, environmental, and risk criteria, regardless of weighting structure.

For transportation, cryogenic trucks remain the optimal option across all demand scenarios under the AHP-weighted case, in contrast to the no-priority MILP results where pipelines become optimal in medium and high demand cases. This difference is mainly driven by the strong prioritisation of CAPEX, where cryogenic trucks benefit from significantly lower initial investment compared to pipeline infrastructure. Similar to the production case, pipelines are unable to fully realise their scale advantages at lower demand levels. Regardless, the score differences still remain small. Pipelines score 0.21 lower than cryogenic trucks in the low-demand scenario, while the difference reduces to 0.05 in both medium and high demand cases. This indicates that even under high CAPEX prioritisation, pipelines remain highly competitive as demand increases. Again, this reflects their underlying economies of scale, where transport cost per unit decreases significantly with increasing volume. In contrast, cryogenic trucks experience increasing marginal energy and operational costs as additional units are deployed.

From a system design perspective, this highlights the importance of demand level in infrastructure selection. At early stages of development, low demand and strong CAPEX sensitivity favour flexible, low-investment solutions such as cryogenic trucks. However, as demand increases, efficiency and scale effects become more dominant, favouring pipeline deployment despite higher upfront costs. This suggests that infrastructure planning should consider staged transitions between transport modes rather than a single static solution. Across all modelling approaches, the results consistently favour a gaseous hydrogen supply chain over a liquid-based alternative. This consistency indicates that both technically optimal solutions and stakeholder-weighted solutions converge on similar system structures. As demand increases, the dominant drivers shift from capital cost considerations towards efficiency and scalability effects.

From an environmental perspective, salt caverns and pipelines, due to their ability to handle larger hydrogen volumes, exhibit lower emissions per unit of hydrogen transported or stored, particularly at higher demand levels. This improvement is mainly due to reduced relative energy losses and improved system efficiency at scale. However, these outcomes are influenced by regional conditions such as energy mix and policy frameworks. In regions with strong renewable energy potential, such as Kuwait, large-scale hydrogen deployment can significantly improve environmental performance due to lower lifecycle emissions per unit hydrogen. In contrast, in regions with less favourable energy systems, scaling up may not provide the same environmental benefit. Policy incentives similarly affect feasibility, with stronger policy support enabling faster deployment of large-scale hydrogen infrastructure.

Finally, risk considerations become more relevant under the AHP-weighted framework, particularly in medium and high demand scenarios. Although alkaline electrolysis is associated with higher risk levels, it still ranks highest in low-demand conditions due to compensating advantages in other criteria such as emissions and system lifetime effects. Because AHP weights are fixed, higher-priority criteria become more influential as system scale increases, while secondary criteria play a larger role at low demand. Medium and high demand cases therefore provide a clearer representation of trade-offs between technologies, particularly in terms of efficiency and scalability.

The Kuwait case study revealed that electrolyser performance is highly demand-sensitive, and that there is a threshold of hydrogen demand that needs to be passed in order for comparative advantages such as higher efficiency to initiate. Similar observations were made in the transportation methods, where pipelines' superior performance emerged at higher demands. These results highlight that the construction of a supply chain in real-time will need to align greatly with expected demand profiles, as at some point operational efficiency and scalability offset higher initial capital investments, which can actually be more cost-effective in the long run. The same stands for environmental performance and risk, where static AHP weightings overemphasised secondary criteria at low demand but levelled the criteria to a more realistic reflective level in medium and high scenarios. However, the Kuwait case study considered a single period focusing on long term dynamics. The subsequent Saudi Arabia case studies in Chapter 4.3. adopt a multi-period framework to capture temporal variations in demand, technological maturity, and cost dynamics. To capture the transitional dynamics in the decades from 2025-2060, the Saudi Arabia case study provides a broader range of demand variability to determine if electrolysers, storage and transport systems can achieve their optimal performance when operating at intermediate maturity levels to test if early-stage inefficiencies make alternatives more viable during this period. Furthermore, in this study, AHP rankings were treated as static due to the focus on a one-period model, with weightings assigned based on stakeholder preferences relative to this specific period. However, the multi-period framework in Chapter 4.3., dynamic re-evaluations of AHP weightings are incorporated for each of the 4 time periods analysed to reflect evolving stakeholder priorities.

4.3 Saudi Arabia

The Saudi Arabia case study focuses on the multi-period design of a green HSC network for the Northwestern region of Saudi Arabia, presented in Figure 19. The Northwestern region encompasses the provinces of Al Jawf, Tabuk, Hail, and Al Madinah, spanning a total length of 1,809 km and a total area of 477,089 km² [138,139]. This region in particular is of vast importance to a large number of cross-industry stakeholders, such as investors and policymakers, due to the Northwestern region being where Saudi Arabia's famous NEOM Green Hydrogen Project is situated. This project aims to become the world's largest commercial hydrogen facility focusing entirely on renewable-based, green hydrogen [140]. Furthermore, the Northwestern region is located directly along the coast of the Red Sea, where currently ~14% of global maritime trade and 30% of global containerised trade transit annually [141]. With the establishment of a hydrogen supply chain, the region could benefit from facilitated exports via these well-established export corridors.

Figure 19: Northwestern Saudi Arabia study region

4.3.1 Grid-Based Spatial Assessment

The Northwestern region is spatially discretised into 40 grid cells to ensure adequate geographic representation across the study area. Grid allocation was proportional to the relative land area of each province, as presented in Table 12, yielding the following distribution: Tabuk (12 grids), Al Madinah (12 grids), Hail (10 grids), and Al Jawf (6 grids). The resulting spatial configuration is presented in Figure 22. Each grid cell represents a candidate location for hydrogen production, storage, and transportation via all infrastructure options assessed in this study, as illustrated in Figure 20, which also presents the three objective functions and the four planning periods- 2025, 2035, 2045, and 2060- evaluated across the case study. The integrated MILP–AHP optimisation framework underpinning the Saudi Arabia analysis is presented in Figure 21.

Table 12: Saudi Arabia provincial areas and grid allocation

Province	Area (in km^2)
Al Jawf	85,212
Tabuk	136,000
Hail	103,887
Al Madinah	151,990

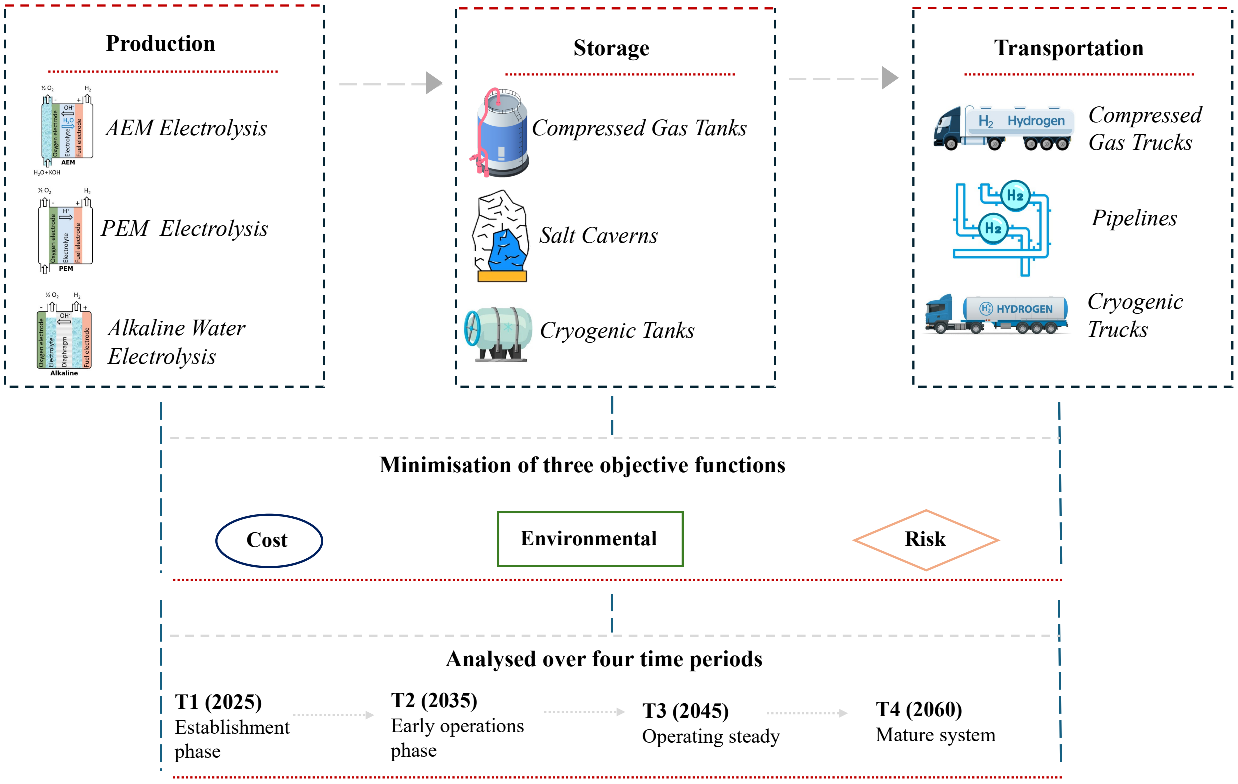


Figure 20: Saudi Arabia hydrogen supply chain network configuration, assessed technologies and planning periods

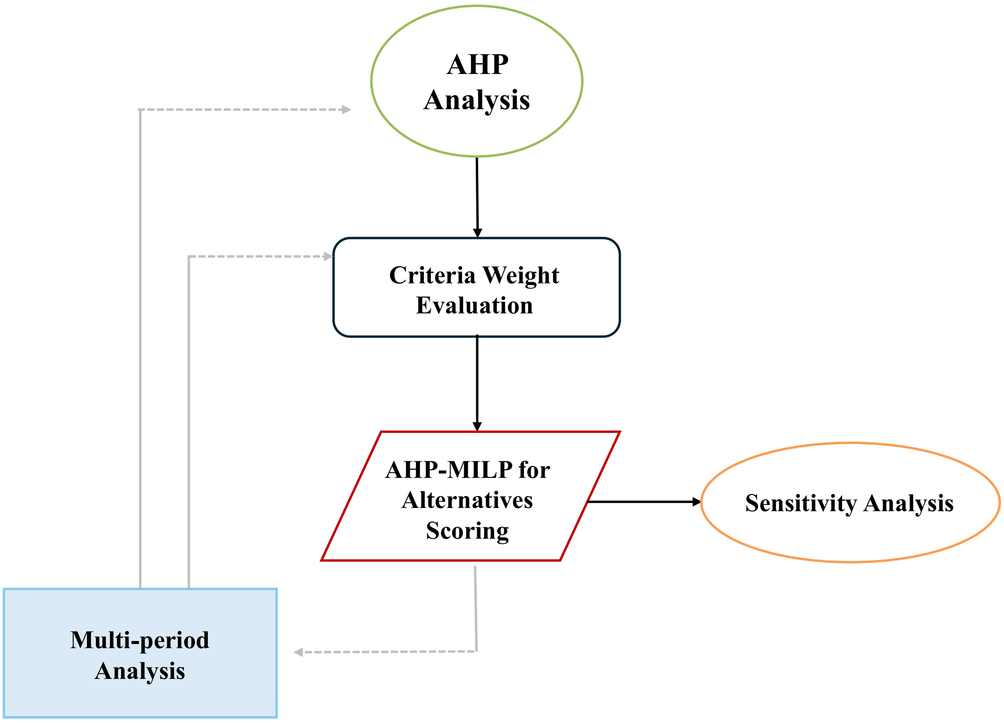


Figure 21: Schematic overview of the integrated MILP–AHP optimisation framework- Saudi Arabia

Similar to Kuwait, Saudi Arabia has no identified salt cavern formations for hydrogen storage and the existing depleted oil reservoirs are located in the Eastern Province, outside the study boundary. This spatial separation removes access to the conventional large-scale geological storage options typically used in hydrogen systems, namely salt caverns and depleted hydrocarbon fields, within the region considered in this study. In the absence of salt cavern storage, the Saq Aquifer is selected as the primary underground storage option. The Saq Formation is a deep, laterally continuous confined aquifer and is treated here as a suitable alternative for porous-media hydrogen storage where evaporite-based formations are unavailable. Within GCC geological settings, aquifer storage is already recognised as a relevant substitute for salt cavern storage in regions lacking suitable halite deposits [142]. In this context, salt caverns would normally represent the preferred geological option due to their high injectivity, excellent sealing characteristics, and cyclic operability. However, given their absence in the Northwestern region, the Saq Aquifer provides the closest large-scale subsurface alternative in terms of storage capacity and seasonal buffering potential.

Sections of the Saq Formation satisfy key technical requirements for underground hydrogen storage, including depths of approximately ~1,100 m and pressures of ~300 bar, which fall within reported feasibility ranges for porous-media hydrogen containment and gas cushion stability [143]. When compared to non-geological alternatives such as compressed gas tanks and cryogenic storage, aquifer-based storage provides significantly higher effective capacity and reduced surface infrastructure requirements, making it more suitable for long-duration and grid-scale storage applications. Based on standard aquifer storage assumptions, approximately 10% of the total estimated aquifer volume of 65 billion cubic metres (BCM) [144] is considered technically accessible and operationally usable for hydrogen storage, corresponding to a storage capacity of 6.5 BCM. This fraction reflects typical practical limitations in porous media systems, including pressure management, sweep efficiency, and operational safety margins, rather than full geological availability. This assumption provides a consistent and comparable basis for modelling large-scale hydrogen storage in the Northwestern region under conditions where salt cavern storage is not geographically available. In the overall system framework, this substitution directly replaces the role that salt caverns would otherwise play in balancing supply variability and providing seasonal storage flexibility, ensuring comparability between the Saudi Arabia case and systems where salt cavern storage is present.

Consistent with the methodological approach established in the Kuwait case study, region-specific parameter adjustments were applied to reflect the climatic and infrastructural conditions of Saudi Arabia. Operational and maintenance costs (OPEX) were marginally increased across all supply chain stages to account for the elevated cooling demands and higher process water costs associated with Saudi Arabia's arid climate (>30 °C) and reliance on energy-intensive desalination as the primary freshwater source, an approach consistent with that adopted in the Kuwait case study and supported by precedent in the literature.

With respect to pipeline transportation, the thermodynamic and materials incompatibility of hydrogen with conventional natural gas infrastructure necessitates the assumption of entirely new pipeline construction rather than network retrofitting. Hydrogen requires approximately four times the energy to transport through a repurposed natural gas pipeline relative to natural gas itself, rendering retrofitting both operationally inefficient and economically unjustifiable at the system scales considered in this study. Accordingly, the capital cost of hydrogen pipeline installation is taken as approximately 68% above that of an equivalent natural gas pipeline [145]. In the Saudi Arabian context, the Master Gas System (MGS)- the nation's primary natural gas transmission network- provides the most appropriate cost benchmark, with an estimated installation cost of approximately USD 1.9 million per kilometre [146]. Applying the 68% hydrogen pipeline cost premium to the Northwestern region's total pipeline corridor length of 1,809 km yields a total capital investment requirement of approximately USD 3.44 billion for the construction of a dedicated hydrogen pipeline network within the study boundary.

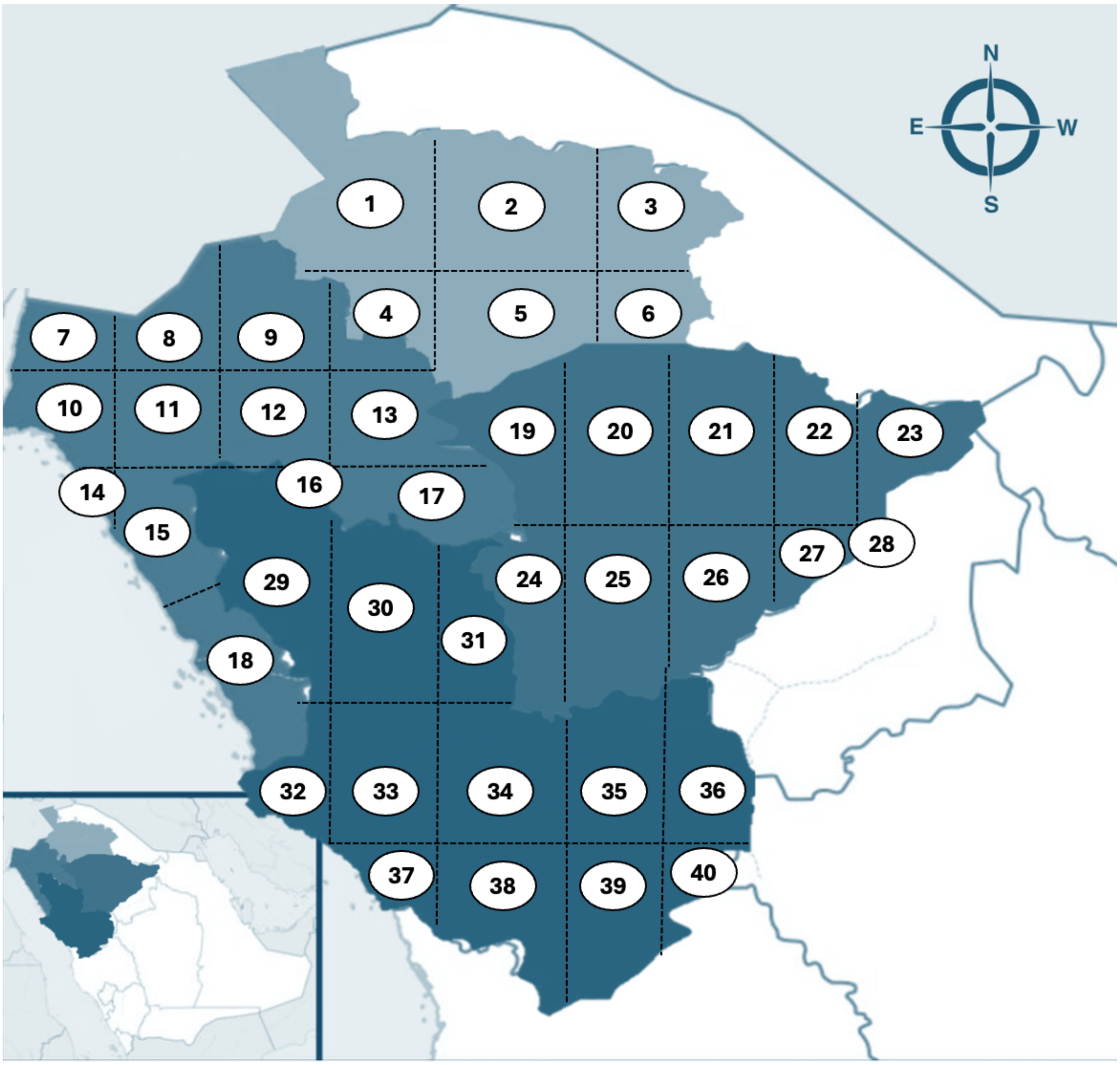


Figure 22: Northwestern Saudi Arabia geospatial grid distribution

Four case studies are defined in Chapters 4.3.2–4.3.5, corresponding to four temporal system stages: T1: 2025 (establishment phase), T2: 2035 (early operations), T3: 2045 (steady-state operations), and T4: 2060 (mature system). For each time period, three demand conditions are evaluated (low, medium, and high), constructed to reflect uncertainty in hydrogen fuel cell vehicle (HFCV) penetration over time. Demand estimation is based on projected HFCV adoption rates mentioned in Chapter 3.2. and is converted into equivalent electrical power requirements for hydrogen production via electrolysis. In this formulation, demand (kW) represents the annualised average electrical load required to satisfy hydrogen fuel consumption.

For T1 (2025), Saudi Arabia is assumed to be in an early demonstration stage for HFCVs, with approximately 10 operational hydrogen vehicles reported in the literature [110-111]. Hydrogen consumption is derived using a conversion of 1 kg H_2 requiring 60 kWh of electricity for production via electrolysis, with each vehicle assumed to support an average driving range of 400 km per kg H_2 [112]. This establishes a per-vehicle equivalent demand of 9 kW, resulting in a total high-demand case of 90 kW for T1. Medium and low demand cases are defined through proportional scaling of the high-demand case, set at 50% (45 kW) and 20% (18 kW), respectively. For T2 (2035), demand is based on Saudi Arabia's hydrogen production target of 4 MTPA, of which 5% is assumed to be allocated to domestic transport applications [113]. The resulting hydrogen allocation is converted into an equivalent electrolysis electricity demand, yielding a high-demand value of 760,000 kW. Applying the same proportional scaling structure produces medium- and low-demand cases of 380,000 kW and 152,000 kW, respectively. The same methodology is extended to T3 (2045) and T4 (2060), using projected national hydrogen production levels and assumed domestic allocation shares for HFCV usage. This ensures consistency in demand construction across all temporal stages while preserving comparability between scenarios. Final demand values for all time periods are summarised in Table 13.

Table 13: Saudi Arabia green hydrogen demand in the transport sector (2025-2060)

Time period	**Low (kW)**	**Medium (kW)**	**High (kW)**
T1 (2025)	18	45	90
T2 (2035)	152,000	380,000	760,000
T3 (2045)	209,000	522,500	1,045,000
T4 (2060)	562,800	1,407,000	2,814,000

Figures 23-25 present the schematic AHP pairwise matrices for each of the economic, environmental and safety/risk criteria evaluated in the case studies.

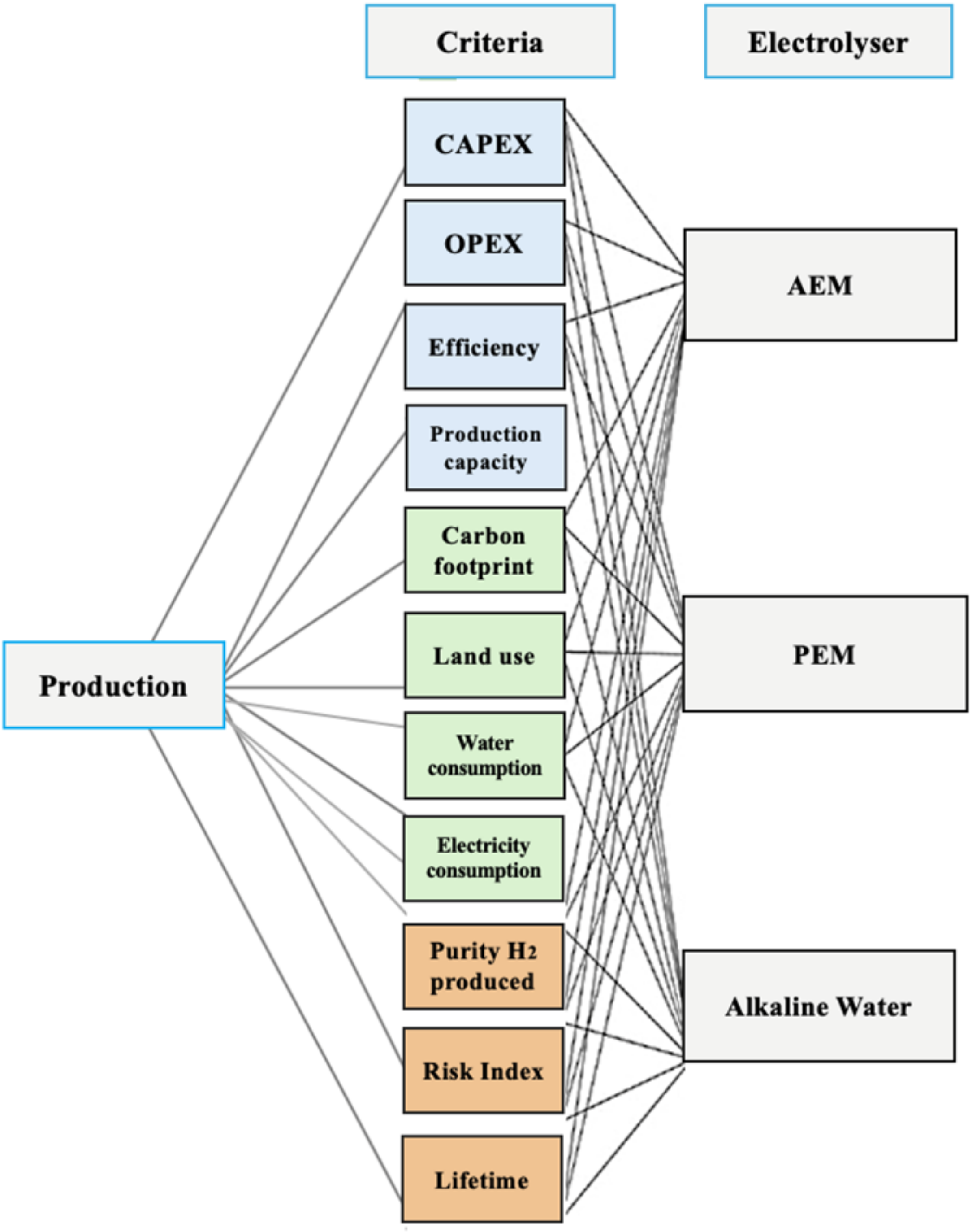


Figure 23: AHP hierarchical schematic for hydrogen production criteria- Saudi Arabia

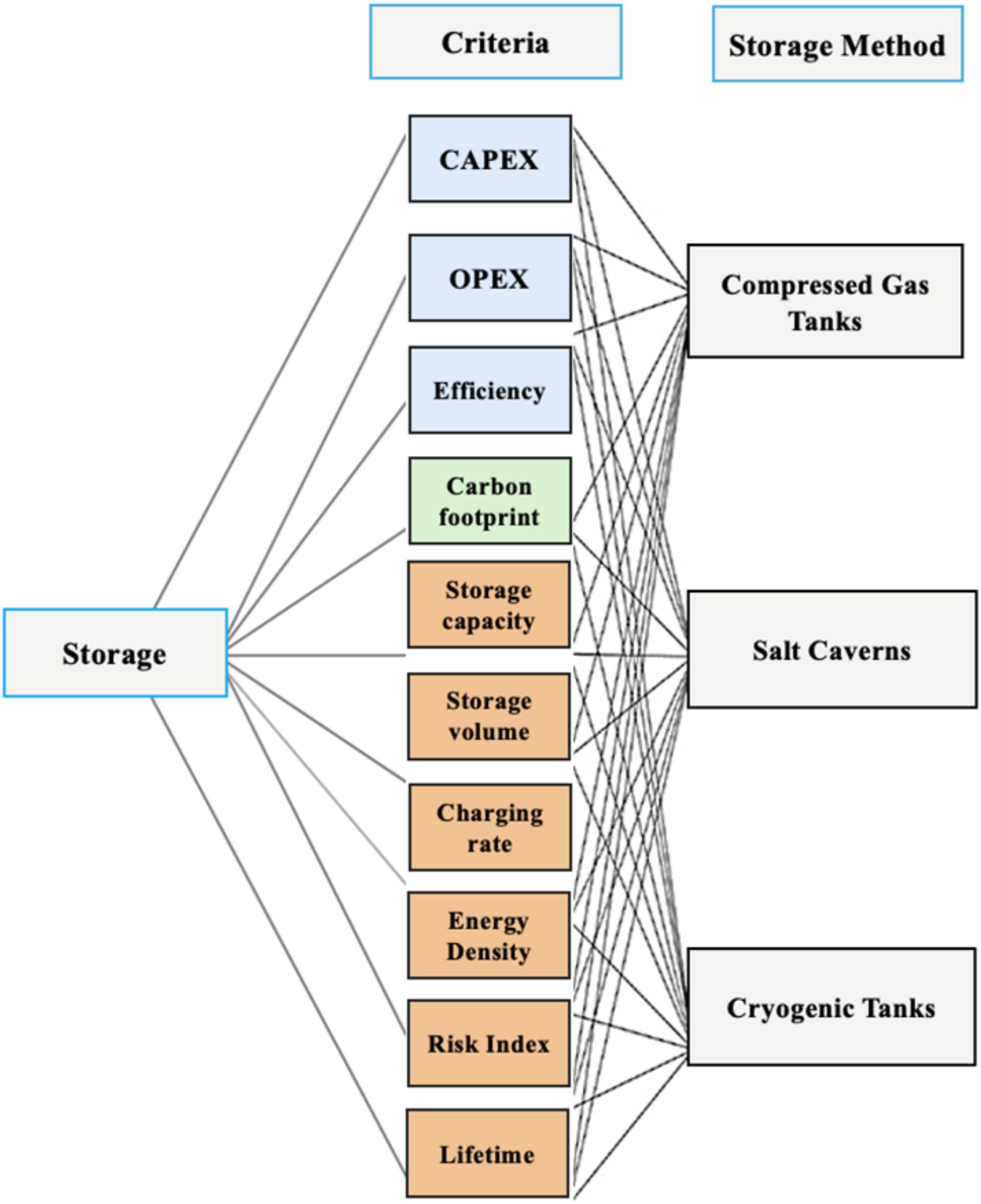


Figure 24: AHP hierarchical schematic for hydrogen storage criteria- Saudi Arabia

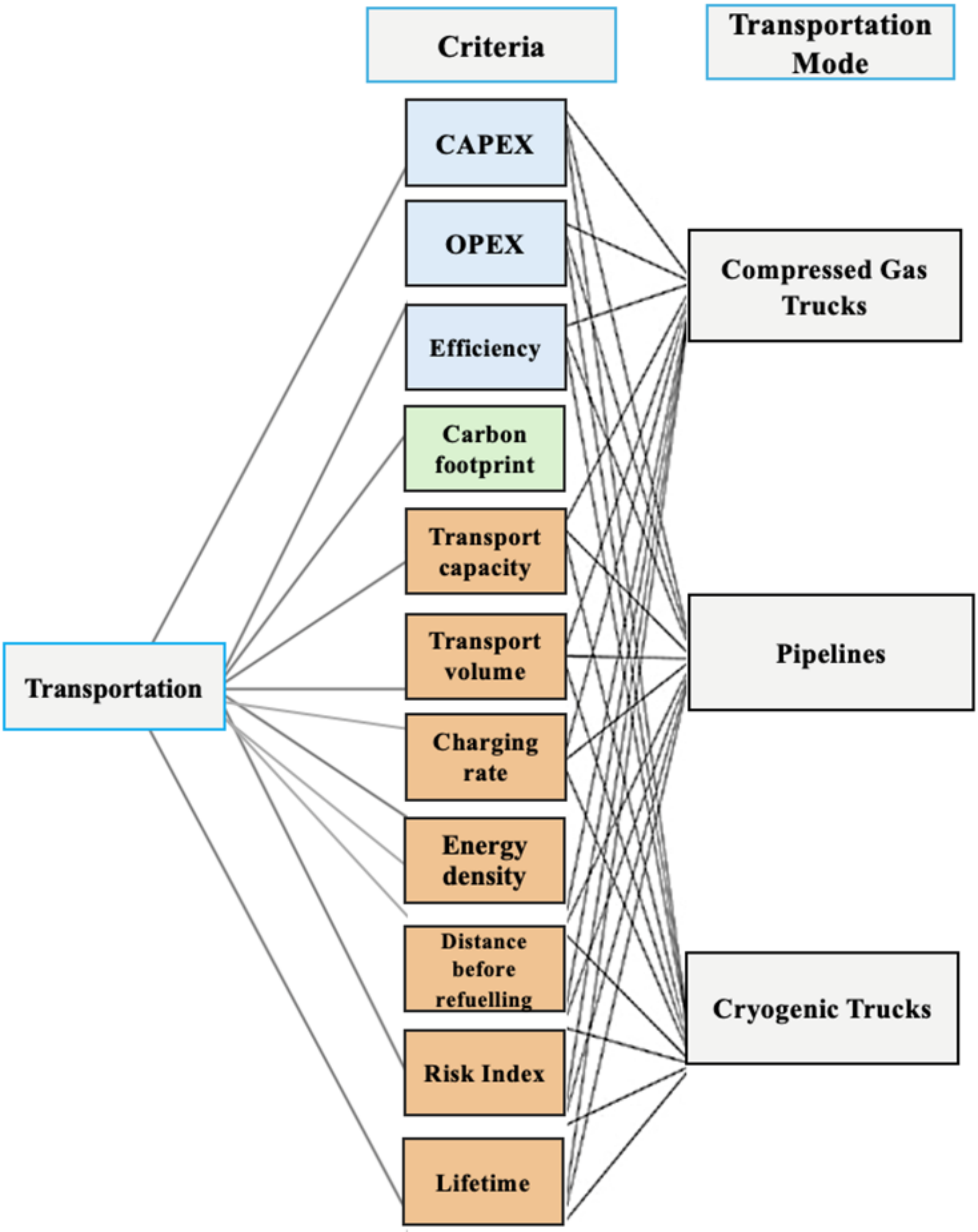


Figure 25: AHP hierarchical schematic for hydrogen transportation criteria- Saudi Arabia

As mentioned in Chapter 4.1., the same core criteria are assessed across production, storage, and transportation in both the Kuwait and Saudi Arabia case studies. However, in the Saudi Arabia case study, production capacity is introduced as an explicit evaluation criterion, whereas it is excluded in the Kuwait case. This distinction is based on the different roles that capacity constraints play in each system context. In the Kuwait case study, production capacity is already implicitly enforced through the demand satisfaction constraints within the optimisation model. As a result, any selected technology must inherently meet the required demand levels, meaning capacity does not independently influence technology discrimination. Including it as a separate criterion in this case would therefore be redundant and could lead to overlapping representation of the same constraint within both the objective function and the decision matrix.

In contrast, the Saudi Arabia case study operates under a more expansion-oriented system structure across multiple time periods. Under these conditions, differences in production capacity between technologies become more pronounced and directly relevant to system scalability. Capacity is no longer only a feasibility constraint embedded in demand satisfaction, but also a distinguishing factor affecting expansion potential, investment scaling, and long-term deployment strategy. For this reason, explicitly including production capacity in the Saudi Arabia evaluation framework allows the model to capture technology-specific limitations under low, medium and high-scale operation conditions. This improves the ability of the optimisation to differentiate between technologies not only on cost and efficiency, but also on their suitability for sustained large-scale hydrogen production over time. Overall, this asymmetric treatment ensures that the criteria set in each case study remains context-dependent, non-redundant, and aligned with the dominant system drivers, thereby improving both methodological consistency and interpretability of the results.

4.3.2 2025 (T1) Results- Saudi Arabia

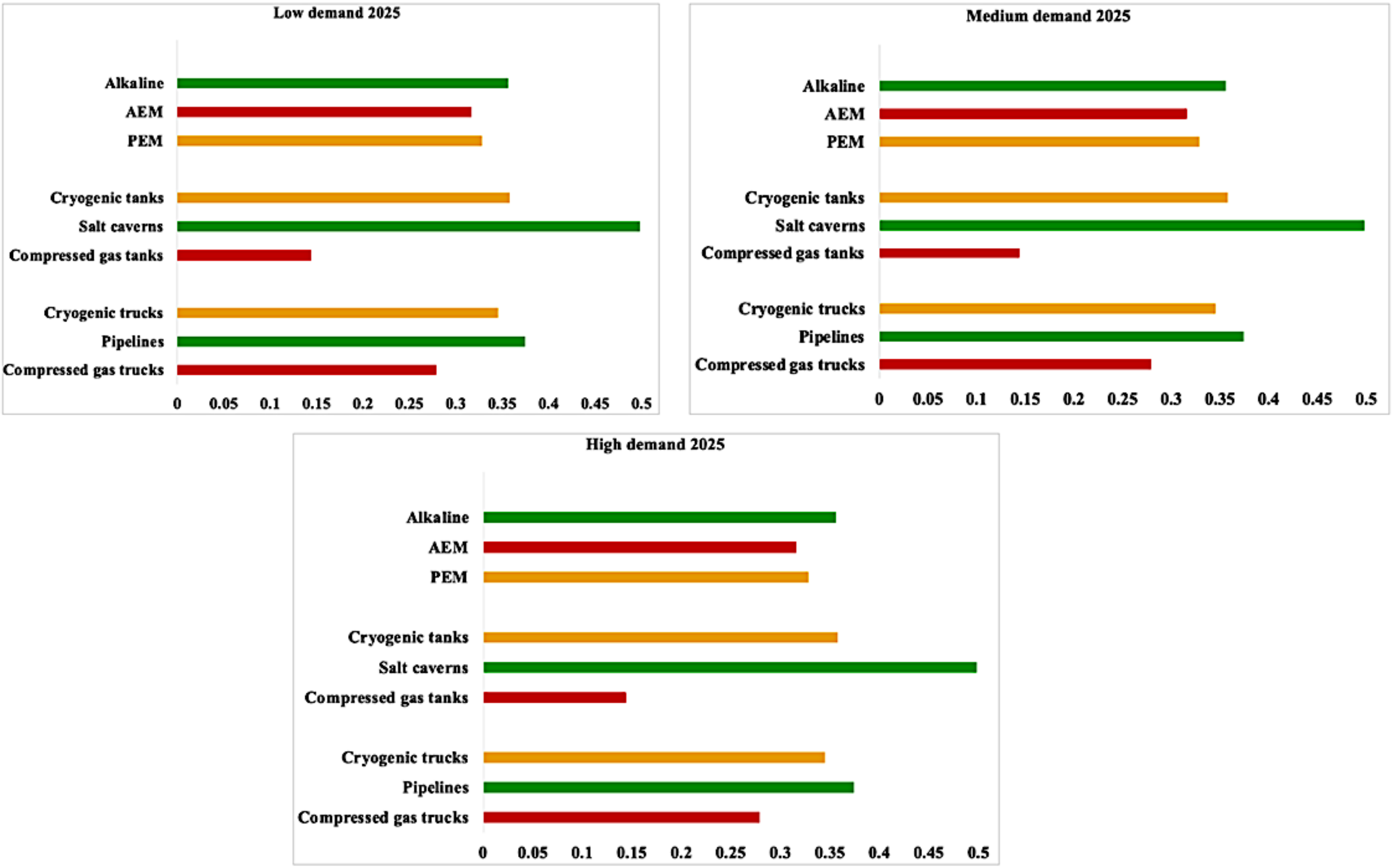


Figure 26: Dynamic MILP results- T1 2025, low, medium and high demand, Saudi Arabia

In the results figures, the green bar indicates the highest-ranked option, yellow represents the second-best, and red denotes the lowest-performing alternative. For hydrogen production in the establishment phase (T1: 2025), alkaline water electrolysis emerges as the top-performing technology. At first inspection, this outcome appears to be primarily driven by the high weighting assigned to CAPEX, as alkaline systems exhibit the lowest capital cost among the electrolysers. However, this explanation alone is insufficient, particularly given that pipelines rank highest in transportation despite having the highest CAPEX within that category. This indicates that single-criterion dominance does not fully explain ranking outcomes, and that multi-criteria interactions must be considered to properly decipher these outcomes. A more complete explanation lies in the interaction between production capacity utilisation and efficiency. In T1, efficiency is also a highly weighted criterion, and alkaline water electrolysis is, in absolute terms, the least efficient technology. Despite this, it performs best, indicating that efficiency must be evaluated relative to operating conditions rather than as a fixed parameter, similar to the results obtained in the Kuwait case study. At low demand levels, electrolysers operate below nominal capacity, and under these conditions, alkaline systems demonstrate greater tolerance to part-load operation, maintaining relatively stable efficiency. In contrast, PEM and AEM electrolysers experience more pronounced efficiency degradation when operating below optimal utilisation levels, as reflected in their reduced performance within the model. This establishes a key system-level dynamic: under early-stage deployment conditions, technologies with higher operational flexibility can outperform those with higher peak efficiency. Since demand in T1 is both low and uncertain, the ability to sustain stable performance under partial load becomes more influential than maximum efficiency at full capacity. As a result, alkaline water electrolysers benefit not only from lower CAPEX but also from reduced sensitivity to underutilisation, which strengthens their overall ranking under the applied weighting structure. A related interaction is observed in relation to risk. Although alkaline electrolysis is characterised by a higher inherent risk index, it still ranks highest despite risk being strongly weighted. This reflects the coupling between utilisation, operational stability, and effective risk exposure. Under low-demand conditions, systems operate away from high-intensity regimes, reducing the likelihood of failure modes associated with dynamic or unstable operation. Because alkaline electrolysers maintain stable performance under partial load, the operational manifestation of risk is effectively moderated relative to technologies that experience efficiency variability under the same conditions. As a result, the static risk classification does not directly translate into equivalent system-level impact, allowing alkaline systems to retain a competitive advantage.

For storage, salt caverns consistently rank as the optimal solution across demand scenarios. In contrast to electrolysers, storage technologies are not strongly affected by utilisation levels. CAPEX is defined per unit of installed storage capacity rather than per unit of hydrogen actively stored, meaning that underutilisation does not impose a direct performance penalty. Salt caverns, characterised by very high storage capacity and low normalised CAPEX, therefore maintain strong performance even when demand is low and available capacity is not fully utilised. This highlights a fundamental distinction between production and storage subsystems: production performance is utilisation-dependent, whereas storage performance is capacity-driven. Consequently, large-scale geological storage options such as salt caverns provide system-level value through long-term buffering capability, enabling demand growth without requiring immediate full utilisation. This structural advantage explains their consistent dominance across weighting scenarios.

For transportation, pipelines rank highest in T1 despite CAPEX being the most heavily weighted criterion. This outcome is not driven by a single dominant parameter, but rather by a compensatory multi-criteria aggregation effect. While pipelines are penalised under CAPEX, this disadvantage is offset by strong performance across multiple highly weighted criteria, including efficiency, operational stability, lifetime, and transport capacity. Unlike storage, where dominance is primarily capacity-driven, pipeline performance emerges from alignment across several system-relevant dimensions. Efficiency plays a critical role in this context. Although cryogenic trucks exhibit a slightly higher nominal efficiency (60%) compared to pipelines (57%), this metric must be interpreted within a system-level framework. Pipeline transport maintains relatively stable efficiency without requiring continuous external energy input, whereas cryogenic transport depends on energy-intensive liquefaction processes and ongoing boil-off management. These additional energy requirements introduce implicit penalties across multiple criteria, particularly OPEX and overall system efficiency, which are captured within the evaluation framework. As a result, pipelines achieve a higher overall score despite marginally lower nominal efficiency, due to their more stable and less energy-dependent operation. This reinforces a broader pattern observed across both production and transportation: technologies that deliver stable, scalable performance under real operating conditions outperform those with higher theoretical efficiency but greater sensitivity to operational constraints.

The T1 results demonstrate that early-stage hydrogen system design is governed not solely by capital cost, but by the interaction between utilisation effects, efficiency stability, and compensatory multi-criteria trade-offs.

4.3.3 2035 (T2) Results- Saudi Arabia

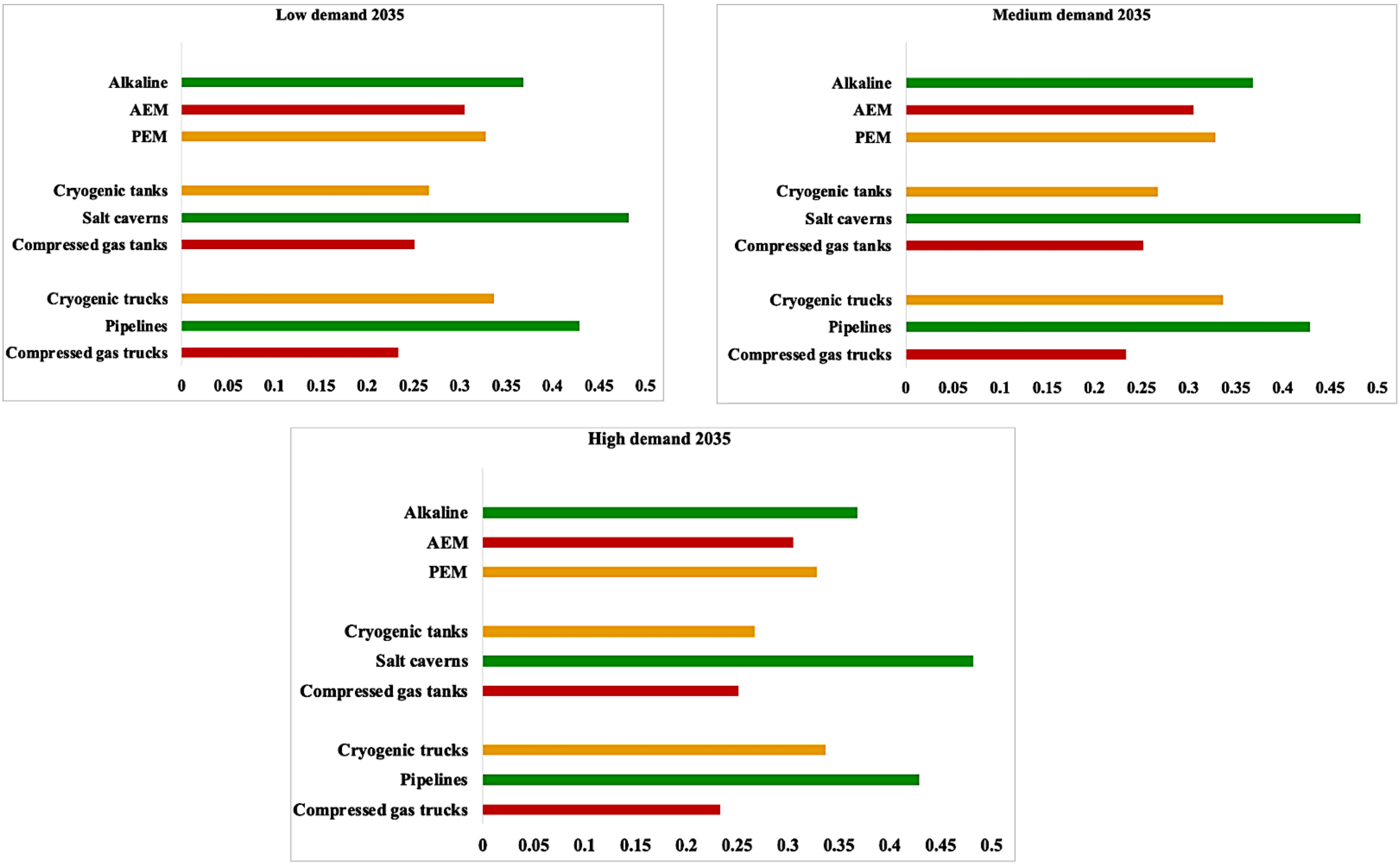


Figure 27: Dynamic MILP results- T2 2035, low, medium and high demand, Saudi Arabia

For production, similarly to T1, alkaline water electrolysis remains the highest-ranked electrolyser across demand scenarios. However, unlike T1, where performance was primarily driven by part-load tolerance under low utilisation, the dominance of alkaline water in T2 (2035) is increasingly governed by scale-dependent effects. As demand rises, electrolysers operate closer to nominal capacity, and the ability to deliver large absolute hydrogen volumes per unit becomes a more significant determinant of system performance. In this context, alkaline water electrolysers, with higher individual unit capacities (≈20 MW), reduce the need for modular scaling through multiple smaller units. This consolidation effect lowers system-level CAPEX not only through reduced equipment count but also through balance-of-plant simplification and lower installation complexity. As a result, the capital cost advantage of alkaline systems is reinforced rather than diminished at higher demand. In addition to capacity effects, the interaction between production scale and renewable integration becomes more pronounced. Larger-capacity alkaline units allow for more stable operation under fluctuating renewable input, particularly in solar-dominated systems typical of the GCC. Rather than requiring frequent ramping across multiple smaller units, higher-capacity systems can absorb variability more effectively at the system level, maintaining operation within efficient load bands. This reduces dynamic efficiency penalties and contributes to more stable overall performance under variable supply conditions. A further relationship that becomes critical at this stage is the coupling between efficiency, lifetime, and utilisation. Although PEM electrolysers exhibit slightly higher nominal efficiency (≈75%) compared to alkaline systems (≈70%), this advantage must be evaluated in the context of sustained high utilisation. In T2, where electrolysers operate closer to full capacity, cumulative operating hours increase significantly, and lifetime becomes a key economic parameter. Alkaline electrolysers, with longer operational lifetimes (≈90,000 hours vs ≈70,000 hours for PEM), distribute both CAPEX and OPEX over a greater total hydrogen output. This effectively lowers the levelized cost of production when evaluated over the system lifetime. Moreover, higher utilisation intensifies maintenance cycles in PEM systems due to increased operational stress, particularly under near-continuous operation. This introduces additional OPEX burdens and potential downtime, which are implicitly captured in the model through reduced effective performance. As a result, the marginal efficiency advantage of PEM is offset by reduced durability and higher maintenance intensity under scaled conditions. Consequently, alkaline electrolysis maintains the highest ranking due to its combined advantages in capacity, lifetime, and operational stability, which together outweigh marginal differences in nominal efficiency. These results indicate that as hydrogen systems transition from low to medium demand, the dominant performance drivers shift from flexibility under underutilisation to durability and scale efficiency under sustained operation. Technologies that can maintain stable performance over extended operating hours become increasingly advantageous within system-level optimisation.

For storage, salt caverns again emerge as the optimal option. At this stage, the interaction between efficiency, energy density, and OPEX becomes more structurally significant. Salt caverns exhibit very high storage efficiency (≈95%) but relatively low energy density (≈7 kg/m^3), whereas cryogenic storage offers significantly higher energy density (≈70.8 kg/m^3) but lower efficiency (≈60%) and higher operational costs. While energy density provides an advantage in space-constrained systems, its relative importance decreases in large-scale, land-abundant contexts such as the GCC, where spatial constraints are less binding. As system throughput increases in T2, cumulative energy losses associated with storage become more impactful. Cryogenic storage incurs continuous energy penalties due to liquefaction requirements and boil-off losses, which scale with stored volume and duration. These losses translate directly into higher OPEX and reduced effective system efficiency. In contrast, salt caverns, once pressurised, require minimal additional energy input to maintain stored hydrogen, resulting in significantly lower marginal energy losses over time. This makes storage efficiency a dominant factor at higher demand levels, outweighing the benefits of higher volumetric density. A further advantage arises from the interaction between storage capacity and lifetime. Salt caverns provide very large storage capacities with long operational lifetimes, allowing them to accommodate increasing demand without requiring proportional reinvestment. This creates a structural advantage in system planning, as capacity expansion does not necessitate repeated infrastructure deployment. In contrast, cryogenic systems require continuous capital and operational input for refrigeration infrastructure, and their shorter lifetimes introduce recurring replacement costs. These factors collectively increase lifecycle cost and reduce their competitiveness under scaled conditions.

For transportation, pipelines again rank highest in T2, but the underlying dynamics differ from T1. The score difference between pipelines and cryogenic trucks increases (≈0.08 in 2035 compared to ≈0.02 in 2025), despite CAPEX being more heavily weighted in T1. This indicates a shift in dominant performance drivers from capital sensitivity to scale-dependent efficiency and throughput. At low demand (T1), cryogenic trucks are penalised by inefficiencies associated with small, intermittent flows. Liquefaction energy requirements and boil-off losses represent a disproportionately large fraction of total transported energy, reducing overall efficiency. Pipelines, by contrast, benefit from continuous flow and low operational variability, allowing them to maintain stable performance even under low utilisation. As demand increases in T2, flow rates become larger and more consistent, allowing both transport modes to operate closer to their optimal conditions. However, pipelines exhibit stronger scaling behaviour due to their non-linear cost structure, where marginal transport cost per unit decreases with increasing throughput. This is driven by the fact that pipeline energy consumption does not increase proportionally with transported volume, enabling higher efficiency at scale. Cryogenic trucks, while benefiting from improved utilisation at higher demand, still incur cumulative energy penalties associated with liquefaction and boil-off, which scale with total transported volume. In addition, increased fleet requirements introduce logistical complexity and rising marginal costs. As a result, although cryogenic transport becomes more competitive relative to T1, pipelines strengthen their advantage under higher demand due to superior scalability, lower marginal energy losses, and more stable operational characteristics.

The T2 results demonstrate a clear transition in system behaviour. As demand increases, performance is no longer dominated by flexibility under low utilisation, but by the ability to operate efficiently at scale, minimise cumulative losses, and sustain long-term operation. This shift reinforces the importance of considering dynamic demand conditions in hydrogen supply chain design, as the relative advantages of technologies are highly dependent on system scale and utilisation regime.

4.3.4 2045 (T3) Results- Saudi Arabia

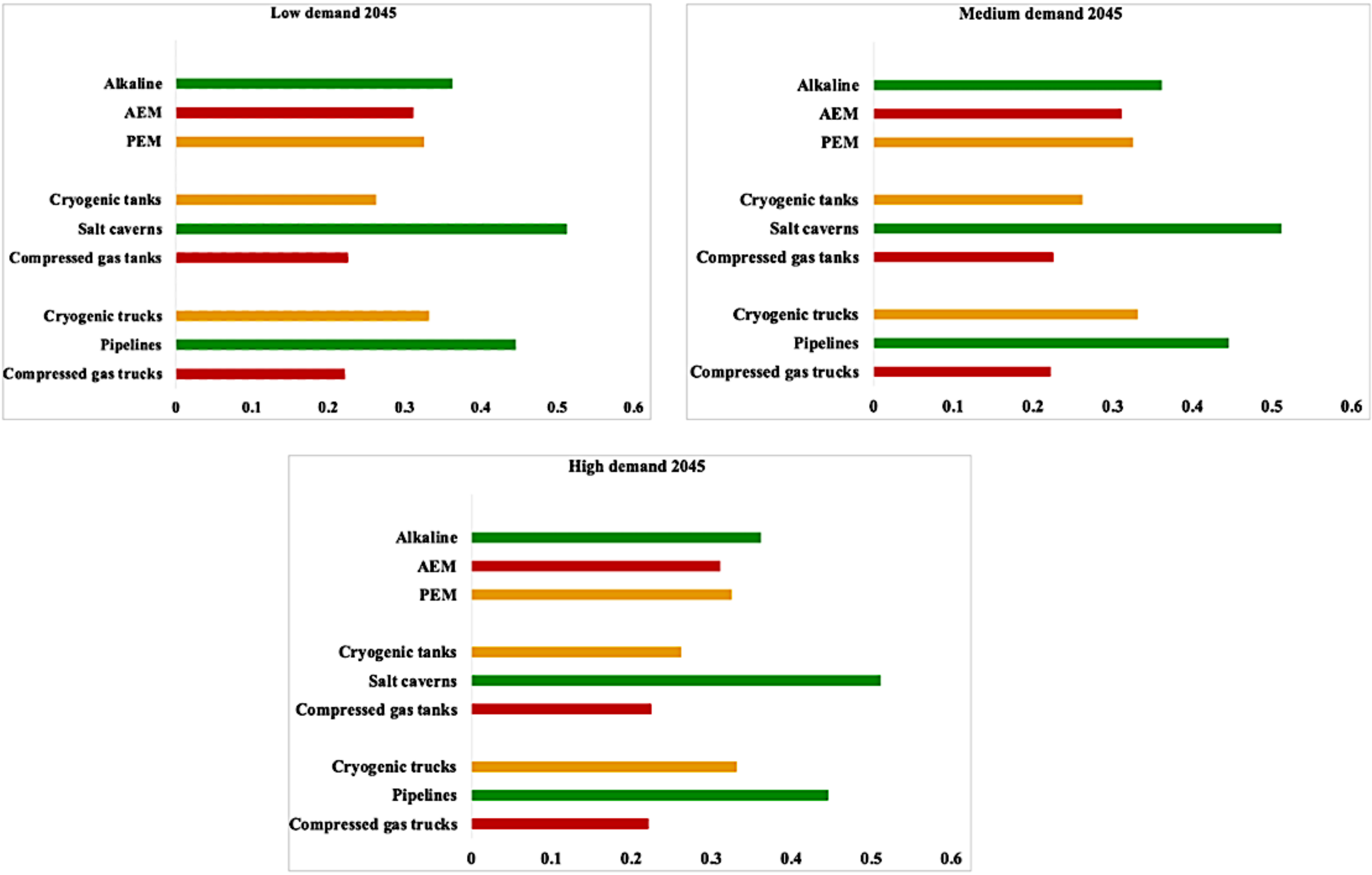


Figure 28: Dynamic MILP results- T3 2045, low, medium and high demand, Saudi Arabia

In T3, alkaline water electrolysis continues to rank as the optimal production technology across all demand scenarios. At this stage, production capacity becomes a structurally dominant factor in determining performance. By 2045, hydrogen demand is large, continuous, and industrially embedded, meaning that systems operate under sustained high utilisation. Under these conditions, alkaline water electrolysers, with high unit capacities (≈200 MW), reduce overall system complexity by limiting the number of required stacks and associated auxiliary components. This consolidation improves system availability by reducing points of failure and simplifying maintenance requirements. As a result, at mature stages of hydrogen system development, technologies that enable large-scale, centralised production provide a clear advantage in maintaining operational stability while minimising infrastructure redundancy. However, the performance gap between alkaline water and PEM narrows (≈0.03) in 2045. This is not due to a decline in alkaline performance, but rather reflects a shift in the relative influence of key criteria, particularly risk and carbon footprint, under high-demand conditions. As demand increases, electrolysers operate closer to their nominal capacity for extended periods, meaning that risk is no longer mitigated by underutilisation, as was the case in earlier stages. Instead, the inherent risk characteristics of each technology become more directly expressed at the system level. For alkaline electrolysis, operating near its full 200 MW capacity increases exposure to potential failure modes, making risk penalties more binding within the evaluation. In contrast, PEM electrolysers, which have a lower inherent risk profile, experience less amplification of risk under these conditions. This reduces the performance gap, as risk transitions from a secondary factor to a constraint that directly influences system feasibility at scale. This demonstrates that, as hydrogen infrastructure matures, operational risk becomes increasingly critical, particularly for technologies deployed in large, continuously operating facilities. A further mechanism contributing to this convergence is the interaction between carbon footprint and risk at scale. In 2045, both criteria carry high weightings (carbon footprint ≈0.135; risk ≈0.136), and their effects are not independent. Alkaline electrolysis exhibits a significantly lower carbon footprint (≈2.41 kg CO_2e/kg H_2) compared to PEM (≈6.07 kg CO_2e/kg H_2), which strongly incentivises its deployment at large scale due to cumulative emissions savings. However, this same scaling effect increases system exposure, as larger and more centralised facilities concentrate production, thereby increasing the impact of potential operational failures. As a result, a coupled trade-off emerges: while lower carbon intensity promotes large-scale deployment, it simultaneously amplifies the consequences associated with higher-risk technologies. In this context, the environmental advantage of alkaline electrolysis indirectly intensifies its risk disadvantage, allowing PEM to gain relative competitiveness despite its higher emissions intensity. This highlights an important system-level interaction in large-scale hydrogen design, where environmental and risk criteria become interdependent under high utilisation.

For storage, salt caverns remain the dominant option in 2045 (≈0.512), significantly outperforming compressed gas tanks (≈0.225) and cryogenic storage (≈0.262). At this stage, storage capacity becomes a system constraint rather than a secondary attribute. With capacity carrying the highest weighting (≈0.124), and salt caverns offering very large storage volumes (≈20,000 tonnes), they are uniquely capable of decoupling continuous hydrogen production from variable consumption patterns. This decoupling function is critical at high demand levels. Rather than requiring storage systems to dynamically respond to fluctuations in demand, salt caverns absorb variability, allowing production to operate continuously at optimal conditions. This behaviour is consistent across all demand scenarios, indicating that system optimisation prioritises buffering capability over responsiveness. If storage were tightly coupled to consumption, lower-demand scenarios would favour modular and flexible systems such as cryogenic tanks. However, the consistent dominance of salt caverns suggests that large-scale hydrogen systems derive greater value from storage technologies that stabilise system operation rather than track demand variability. Risk dynamics further reinforce this outcome. The risk associated with salt cavern storage remains relatively constant across demand levels, as it is largely governed by geological stability rather than throughput. In contrast, tank-based systems experience increasing risk with higher throughput due to pressurisation cycles, thermal management requirements, and operational handling. This creates an asymmetry in risk scaling: while tank-based storage becomes more exposed as demand increases, salt caverns maintain stable risk characteristics. Combined with their buffering capability, this effectively decouples production from consumption variability, strengthening their system-level advantage.

For transportation, pipelines again emerge as the optimal mode in 2045. At this stage, performance is primarily governed by efficiency, continuity, and risk rather than capital cost. Similar to T2, the score gap between pipelines and cryogenic trucks increases relative to 2025, reflecting a shift in dominant performance drivers as demand scales. At high demand levels, cryogenic transport incurs increasing efficiency penalties due to its reliance on energy-intensive liquefaction and continuous boil-off management. These processes introduce persistent energy losses that scale with transported volume, reducing overall system efficiency. In contrast, pipelines benefit from continuous flow and lower marginal energy requirements per unit transported, allowing them to maintain stable and scalable efficiency. This efficiency differential also propagates into carbon performance. Lower efficiency in cryogenic transport increases the energy required per unit of hydrogen delivered, resulting in higher associated emissions. Pipelines, by maintaining higher effective efficiency, achieve lower emissions per unit transported, creating a reinforcing effect where efficiency and carbon footprint jointly favour pipeline transport. As a result, the economies of scale associated with pipelines become fully evident in 2045. While their high CAPEX remains a disadvantage in early-stage deployment, at mature demand levels this is offset by superior performance across efficiency, emissions, operational stability, and transport capacity. This confirms that, as hydrogen systems scale, transport optimality shifts from flexible, low-investment solutions towards infrastructure that delivers stable, high-throughput performance over long operating periods.

The T3 results indicate that the hydrogen supply chain is entering a scale-intensive transitional regime, in which system behaviour is increasingly shaped by sustained high utilisation, but has not yet reached full saturation where all technologies operate at their intrinsic performance limits. At this stage, optimal configurations favour solutions that reduce system fragmentation and support centralised, high-throughput operation, with alkaline electrolysis, salt cavern storage, and pipeline transport emerging as preferred options due to their ability to deliver stable performance under large-scale deployment conditions. As demand increases, capacity, operational continuity, and system-wide efficiency become progressively more influential, while flexibility and modularity begin to lose relative importance. Risk and environmental performance also become more structurally embedded at system level, although their effects remain partially mediated by operating conditions rather than fully expressed. In this context, alkaline electrolysis benefits from its suitability for large, continuous production blocks, while salt caverns and pipelines reinforce system stability through high-capacity buffering and low-loss transport. Nevertheless, the relatively narrow performance differentials between technologies at T3 indicate that the system has not yet undergone full behavioural divergence. Instead, this period represents a transitional consolidation phase in which scale begins to restructure preferences, but where subsequent increases in demand are still expected to re-balance trade-offs as technologies operate closer to their intrinsic efficiency and risk characteristics in later stages.

4.3.5 2060 (T4) Results- Saudi Arabia

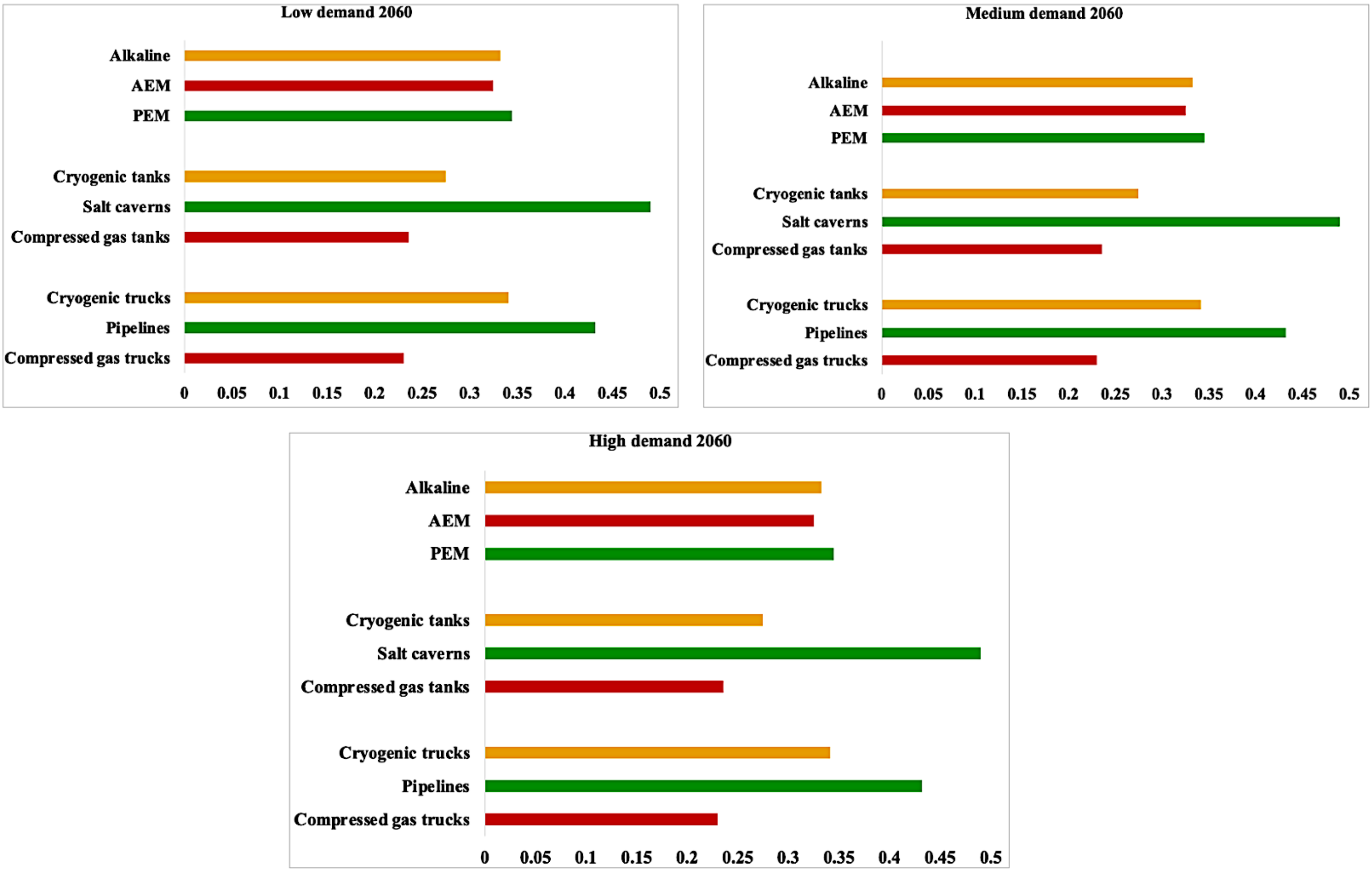


Figure 29: Dynamic MILP results- T4 2060, low, medium and high demand, Saudi Arabia

A change in ranking is observed in 2060 for hydrogen production, where PEM becomes the optimal electrolyser across demand scenarios, overtaking alkaline water electrolysis. This shift is primarily driven by system scale reaching a level where PEM can operate continuously within its optimal efficiency range (~82%). Unlike earlier periods (2025–2045), where PEM performance was constrained by transitional operating conditions and partial-load effects, 2060 demand levels are sufficiently high and stable to ensure continuous utilisation. As a result, PEM’s efficiency advantage is no longer theoretical but fully realised in operational terms, allowing its performance to translate directly into higher overall scores. The key mechanism behind this transition is the removal of part-load penalties. In earlier periods, PEM systems operated below optimal utilisation, which increased maintenance intensity and reduced effective efficiency. By 2060, this constraint is no longer present, meaning that performance is governed primarily by intrinsic efficiency rather than utilisation mismatch. In contrast, alkaline water electrolysis does not exhibit meaningful efficiency gains with increased load. As demand increases, both technologies converge in utilisation, but only PEM benefits from efficiency amplification, which explains the reversal in ranking. Risk becomes increasingly influential at this stage and acts as a secondary driver of the shift. At 2060 scale, alkaline systems operate at very large, centralised capacities (500 MW), meaning that system exposure is no longer diluted by underutilisation. This increases the effective weight of operational risk within the decision framework. PEM, in contrast, benefits from modular deployment, where capacity is distributed across multiple units. This reduces concentration risk and improves system redundancy. The result is that risk transitions from a marginal criterion in earlier periods to a structural constraint at high demand levels, favouring modular technologies. A further interaction occurs between carbon footprint and risk, which becomes more pronounced at scale. Although alkaline water electrolysis has a lower carbon footprint (2.41 kg CO_2e/kg H_2), this advantage incentivises large-scale centralised deployment. At 2060 demand levels, this scaling effect increases system concentration, which in turn amplifies operational risk exposure. This creates a coupled effect where environmental advantage indirectly strengthens a disadvantage in system safety. PEM, despite a slightly higher carbon footprint, avoids this amplification due to its distributed structure, resulting in a more balanced trade-off between emissions and risk.

For storage, salt caverns continue to dominate, and their advantage becomes more structurally entrenched. The widening gap relative to cryogenic tanks reflects not marginal improvements, but scaling behaviour differences across technologies. Salt caverns achieve very high storage efficiency (~99.5%) with minimal active energy input (~0.2 kg CO_2e/kg H_2), meaning that efficiency directly translates into low emissions. This creates a reinforcing relationship between energy use and carbon footprint, where reductions in one simultaneously improve the other. Cryogenic storage follows the opposite pattern. Despite higher energy density, it requires continuous refrigeration, leading to persistent energy losses and higher emissions (~2.8 kg CO_2e/kg H_2). As demand increases, these losses scale with throughput, making cryogenic storage progressively less competitive for long-duration and system-balancing roles. In addition, salt caverns provide inherently high storage capacity, allowing them to absorb large fluctuations without additional infrastructure expansion. This decouples storage from short-term demand variability, which becomes increasingly important at high system scale.

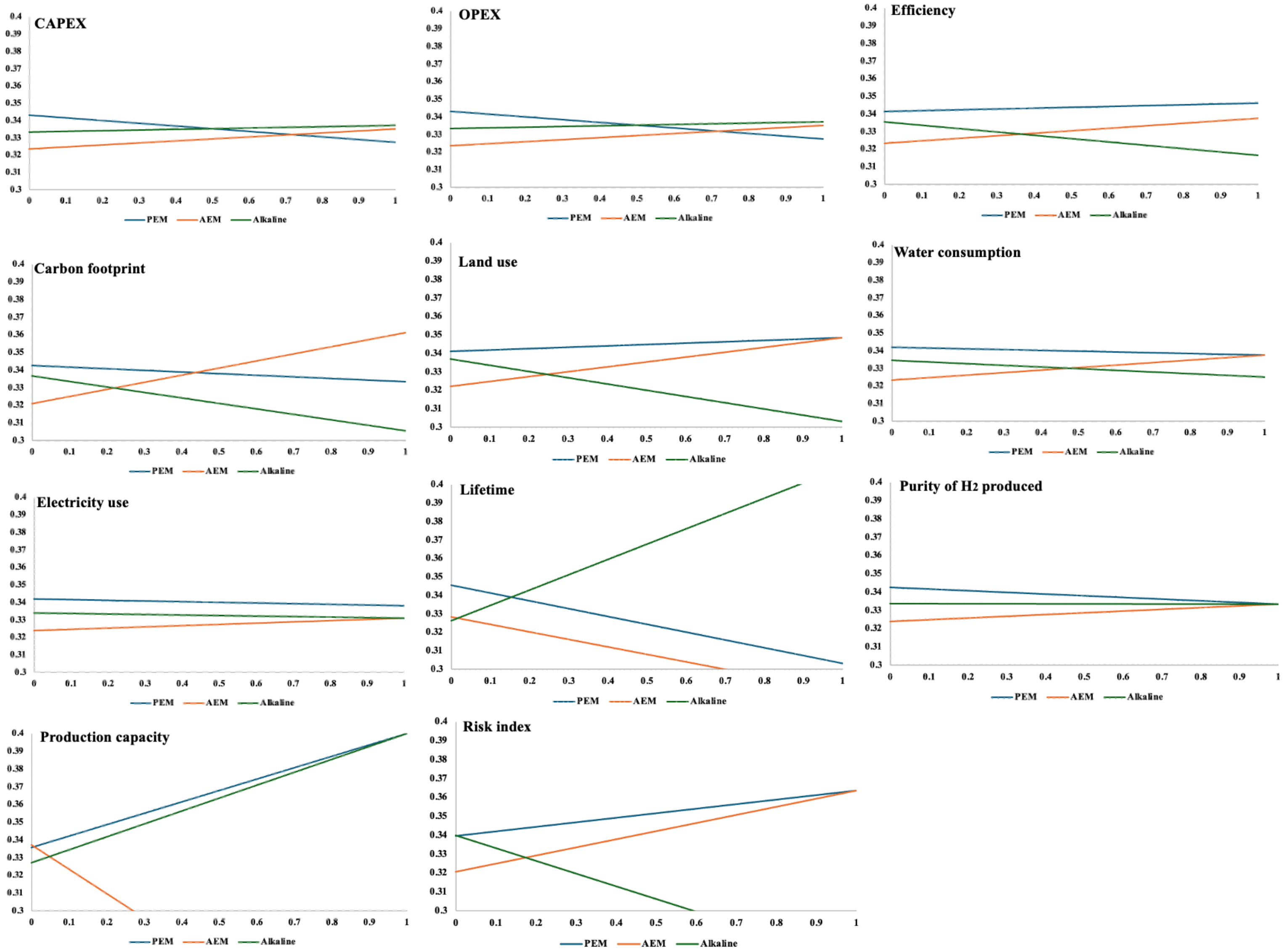
For transportation, pipelines again emerge as the optimal option in 2060, with a larger performance gap compared to cryogenic trucks than in earlier periods. This is not driven by CAPEX, but by cumulative operational advantages that become more dominant at scale. Pipelines operate as a steady-state system with no liquefaction requirement, no boil-off losses, and minimal energy input during transport. This creates simultaneous improvements across efficiency, emissions, and operational stability. Cryogenic trucks, while flexible and competitive in energy density and range, are constrained by continuous energy requirements for liquefaction and storage maintenance. These requirements introduce persistent energy losses, which scale with hydrogen throughput. As demand increases, these losses directly affect both efficiency and carbon footprint, creating compounding penalties across multiple criteria. Pipelines avoid this coupling effect, allowing their advantages to accumulate rather than trade off against each other.

The 2060 results indicate a structural transition in system behaviour. At this stage, technology selection is no longer governed by isolated criteria such as cost or efficiency, but by how strongly performance advantages are preserved or amplified under full-scale, continuous operation. Technologies that exhibit reinforcing performance across multiple criteria become dominant, while those reliant on flexibility or localised advantages lose relative competitiveness as system scale increases.

4.3.6 2060 (T4) Sensitivity Analysis (High-Demand Scenario)- Saudi Arabia

For Saudi Arabia, the sensitivity analysis was conducted for the high-demand scenario at 2060 levels. This selection is justified on the basis that 2060 represents the terminal and fully scaled operating state of the modelling horizon, where the hydrogen system has transitioned into a structurally mature configuration and demand reaches its maximum projected level. At this stage, production, storage, and transportation systems operate near full utilisation, meaning that system performance is governed primarily by intrinsic technology characteristics and binding physical and operational constraints rather than transitional deployment effects such as underutilisation or early-stage capacity ramp-up. Earlier periods (2025- 2045) are characterised by structural transition effects, including partial asset utilisation, incomplete realisation of economies of scale, and stronger CAPEX-dominated selection behaviour. While these conditions can generate local variability in rankings, they are heavily influenced by deployment-stage inefficiencies and therefore do not reflect stable system operation. In such regimes, apparent sensitivity to weighting changes is partially endogenous to the transition dynamics themselves rather than to robust multi-criteria trade-offs, which reduces their suitability for testing structural stability of the optimisation framework. In contrast, the 2060 high-demand case represents a near steady-state, high-utilisation regime in which all technologies are operating within their effective design envelopes. Under these conditions, ranking outcomes are no longer driven by feasibility thresholds or transitional underperformance, but by convergent marginal trade-offs across efficiency, risk, capacity, and lifecycle criteria. This produces a tightly constrained decision space in which alternative technologies exhibit reduced score separation, increasing the relevance of testing whether small perturbations in weighting structure can alter dominance relations. Importantly, while high demand does not automatically guarantee maximum sensitivity, it does maximise the number of simultaneously binding constraints across subsystems (production capacity limits, storage buffering requirements, and transport throughput constraints). This increases the dimensional coupling between criteria, meaning that ranking outcomes are more strongly determined by multi-criteria interaction effects rather than single dominant drivers. As a result, the 2060 high-demand case provides a conservative stress test of ranking robustness under fully coupled system operation, where both convergence of alternatives and constraint saturation are simultaneously active. Accordingly, conducting sensitivity analysis at this stage ensures that observed rankings are not artefacts of transitional system behaviour, nor dependent on narrow weighting perturbations in low-utilisation regimes, but instead reflect structurally stable solutions under maximum system scale and full operational coupling.

Figures 30-32 present the sensitivity analyses results for production, storage and transportation criteria.



CAPEX

OPEX

Efficiency

Carbon footprint

Land use

Water consumption

Electricity use

Lifetime

Purity of H2 produced

Production capacity

Risk index

Figure 30: Sensitivity analysis- hydrogen production criteria, Saudi Arabia (2060 high demand)

For production, the sensitivity analysis identifies risk as the most influential criterion under the 2060 high-demand scenario. At this stage, the system operates in a high-utilisation regime where production assets function close to their nominal design capacities, and ranking sensitivity reflects marginal changes in system-level exposure rather than transitional deployment effects. Within this regime, alkaline water electrolysis exhibits pronounced sensitivity to increases in risk weighting, with small perturbations leading to a rapid reduction in its score and a corresponding increase in PEM performance. This indicates that at full-scale operation, risk behaves as a capacity-amplified criterion, where its influence increases with the centralisation of production assets. This behaviour is consistent with a regime shift in risk interpretation across the modelling horizon. In earlier, low-utilisation conditions (i.e. T1-T3), risk is primarily moderated by underloading effects and partial operation, which reduce exposure intensity at system level. In contrast, at 2060, risk becomes structurally linked to installed capacity, where large-scale single-site or centralised configurations concentrate hydrogen production and therefore increase consequence severity in failure scenarios. This does not imply a change in the intrinsic risk classification of technologies, but rather a change in how risk propagates through system scale. Under these conditions, alkaline water electrolysis exhibits higher sensitivity due to its centralised scaling characteristics. Increased production capacity leads to higher aggregation of hydrogen throughput per installation, which amplifies the system-level impact of failure events. PEM electrolysers, by contrast, benefit from distributed modularity, where production is spatially and operationally decomposed into smaller units. This reduces failure correlation and limits risk propagation, making PEM structurally more robust under increasing risk weighting at high demand. The sensitivity analysis also clarifies the relationship between carbon footprint and risk as co-scaling but non-causally linked criteria. When carbon footprint weighting increases independently, alkaline water improves due to lower emissions intensity per unit hydrogen. However, when risk weighting increases, PEM overtakes alkaline systems. This divergence does not imply direct coupling between emissions and risk, but rather reflects that both criteria are simultaneously amplified by system scale. Larger alkaline installations reduce specific emissions but increase consequence exposure due to centralisation, whereas PEM maintains more distributed exposure with slightly higher emissions. The interaction is therefore scale-mediated rather than structurally dependent. Additionally, PEM performance is strongly dependent on operating regime. At 2060 demand levels, PEM operates closer to its optimal utilisation range, allowing its efficiency advantage to be more fully realised. Sensitivity gradients show that increasing weights on efficiency and capacity improve PEM ranking stability, whereas deviations from optimal loading conditions in earlier periods suppress its performance. This confirms that PEM competitiveness is conditional on sufficient system scale to avoid persistent part-load operation, reinforcing a regime-dependent efficiency effect rather than a static superiority.

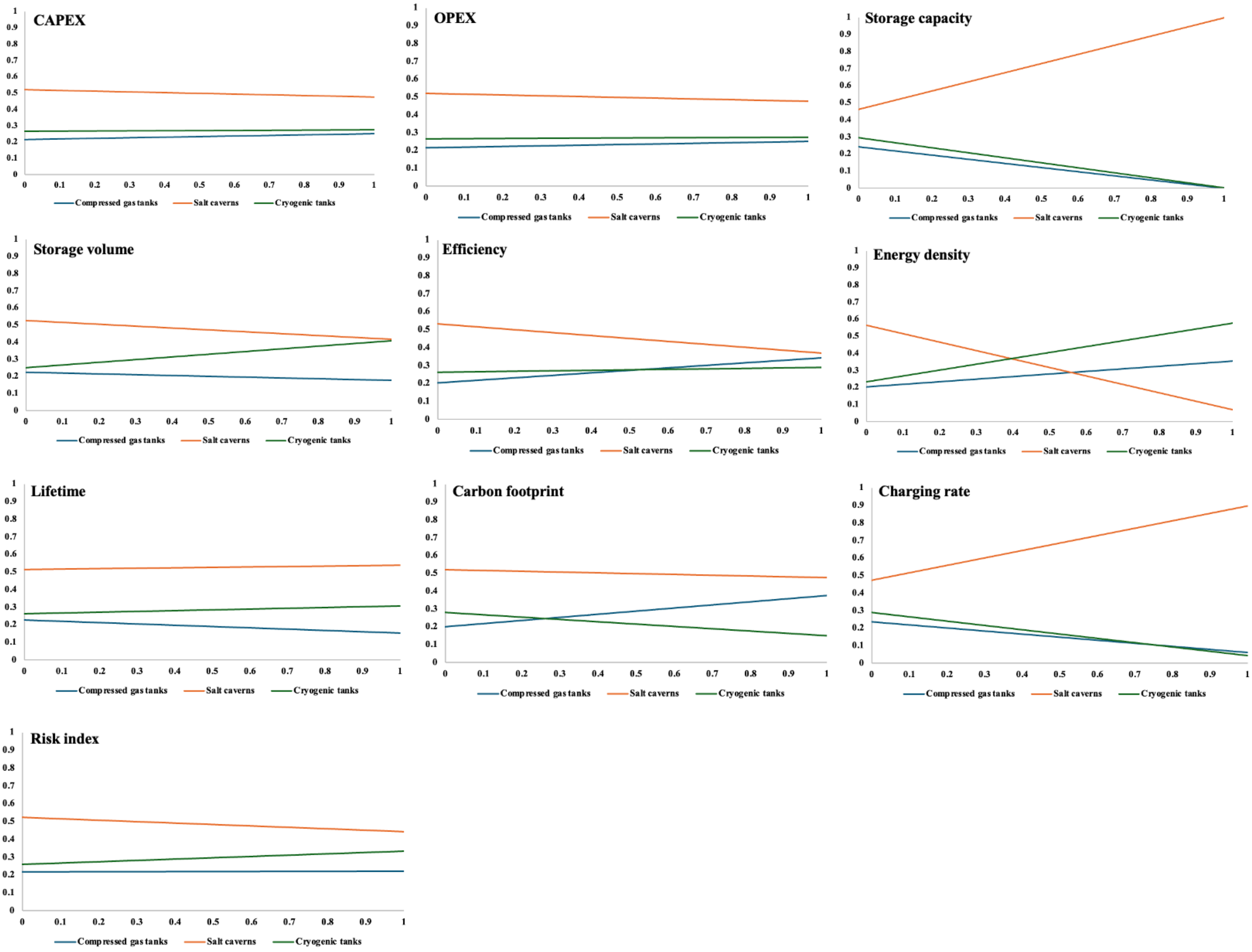


Figure 31: Sensitivity analysis- hydrogen storage criteria, Saudi Arabia (2060 high demand)

For storage, the sensitivity analysis shows high elasticity of rankings with respect to storage capacity, which emerges as the dominant structural constraint at 2060 demand levels. At this scale, storage is governed primarily by its role in temporal decoupling between production and consumption, making volumetric capacity the principal driver of feasibility. As capacity weighting increases, salt caverns exhibit a strong monotonic improvement in ranking due to their inherently large geological storage envelope. In contrast, compressed gas and cryogenic systems experience rapid performance degradation under high capacity weighting, reflecting their fundamentally modular and surface-constrained storage limits. When efficiency is isolated as a criterion, cryogenic storage temporarily improves in ranking due to its higher short-cycle utilisation performance. However, in this context, efficiency represents operational discharge responsiveness rather than long-duration thermodynamic efficiency. This distinction is critical: cryogenic systems optimise short-term deliverability, while salt caverns optimise long-term containment efficiency. Salt caverns, although less responsive under short-cycle efficiency definitions, maintain near-zero marginal losses over long storage durations and exhibit superior performance when capacity and temporal scale are jointly considered. This confirms that storage technologies are fundamentally differentiated by time-scale dependence, where salt caverns dominate long-duration buffering and tank-based systems are constrained to short-duration flexibility.

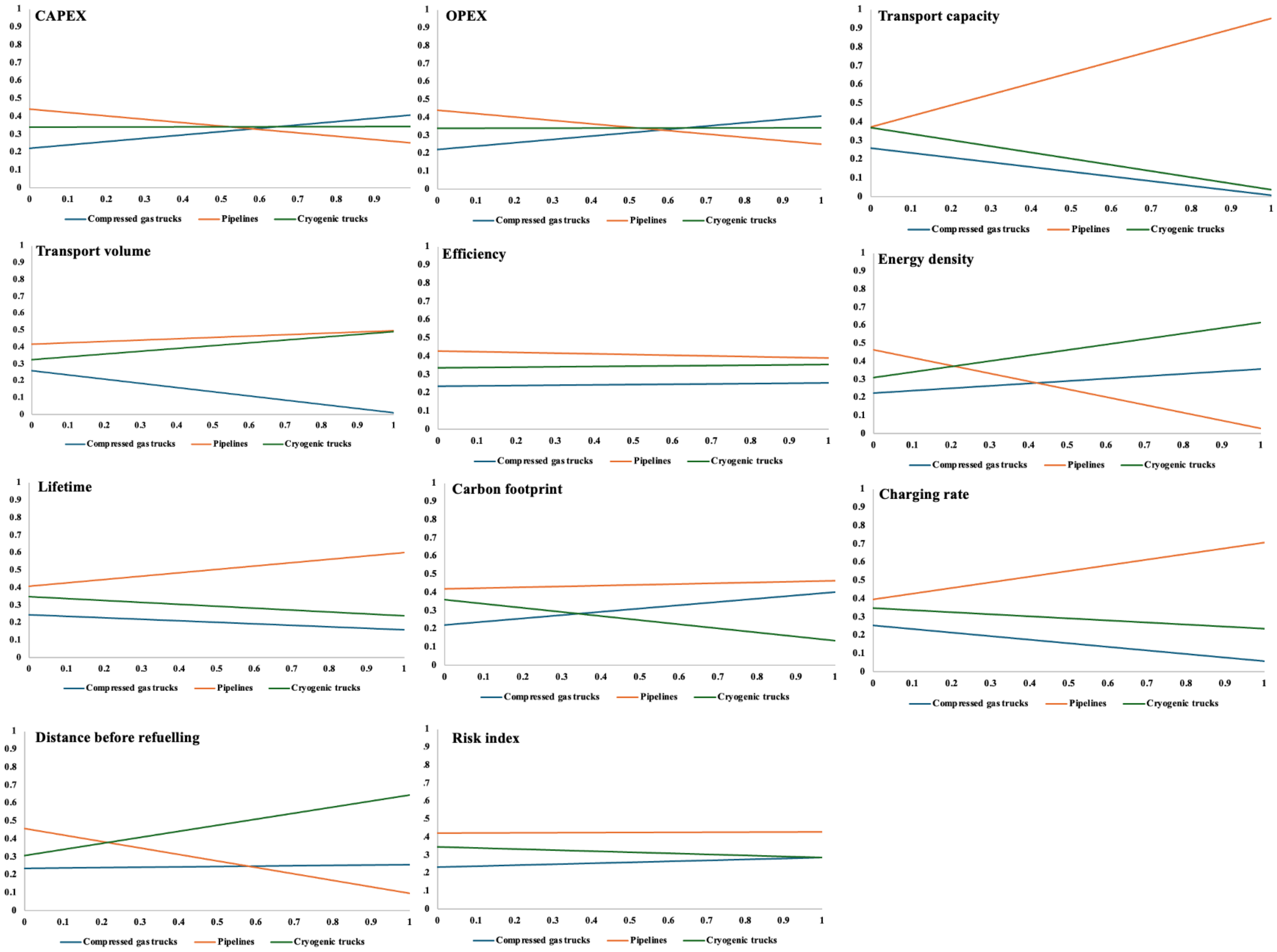


Figure 32: Sensitivity analysis- hydrogen transportation criteria, Saudi Arabia (2060 high demand)

For transportation, sensitivity results highlight a clear trade-off between cost-weighted criteria (CAPEX/OPEX) and system throughput constraints. When CAPEX or OPEX is increased, cryogenic trucks gain relative advantage due to lower infrastructure intensity and deployment flexibility. However, when transport capacity is weighted more heavily, pipelines exhibit a sharp improvement in performance, reflecting their ability to support continuous, high-volume hydrogen transmission. Energy density weighting reinforces this separation but does not override throughput constraints. Cryogenic trucks improve under higher energy density weighting due to higher per-trip hydrogen load, but their discrete operational structure imposes limits through fleet size, routing cycles, and refuelling downtime. Pipelines, by contrast, operate under continuous flow conditions where transport capacity scales with system demand rather than discrete logistics cycles. At 2060 demand levels, transportation is therefore governed by a throughput-dominant regime, where continuous delivery capability becomes the binding constraint. This explains the dominance of pipelines despite higher capital intensity, as system-scale performance is determined by sustained volumetric transfer rather than unit transport efficiency.

Overall, the sensitivity analysis demonstrates that at 2060 demand levels, the hydrogen system operates in a regime where criteria influence is structurally mediated by scale. Production systems are differentiated primarily by risk propagation and modularity, storage systems by time-scale and volumetric capacity, and transportation systems by throughput continuity versus discrete logistics constraints. Rather than indicating single-criterion dominance, the results show that system behaviour is governed by regime-dependent criterion activation, where the importance of risk, capacity, efficiency, and cost shifts as a function of utilisation scale and temporal operation mode. This provides a structurally consistent explanation for ranking stability and sensitivity behaviour across the hydrogen supply chain.

The Saudi Arabia case study results demonstrate that system optimality is not static, but regime-dependent, with technology performance governed by the interaction between scale, utilisation level, and the relative activation of cost, efficiency, risk, and capacity constraints. Across production technologies, the results indicate a continuous transition rather than discrete switching between dominant technologies. In low and medium-demand regimes, alkaline water electrolysis forms the principal production technology due to its low capital intensity and stable operation under partial-load conditions, where underutilisation does not significantly penalise system performance. In these regimes, cost and CAPEX-related criteria dominate decision outcomes, making alkaline systems structurally favourable despite lower nominal efficiency compared to PEM and AEM technologies. As demand increases, the system progressively shifts into a transitional regime in which no single electrolyser dominates across all criteria. In this region, PEM electrolysers gain relative importance due to their modularity, higher intrinsic efficiency, and improved performance under closer-to-nominal operating conditions. However, their advantage is conditional, emerging primarily when utilisation levels are sufficiently high to avoid part-load efficiency penalties. Consequently, PEM does not replace alkaline water abruptly but instead contributes increasingly to marginal capacity in high-demand configurations. At the highest demand level (2060), the results indicate a regime of convergence where performance differences between technologies narrow, and rankings become more sensitive to marginal changes in risk and efficiency weightings. Under these conditions, alkaline water electrolysis and PEM operate in a near-competitive configuration, with dominance depending on the relative prioritisation of risk exposure versus efficiency realisation. This confirms that production optimality is not absolute but dependent on system operating regime and weighting structure.

For storage, salt caverns consistently emerge as the dominant large-scale buffering technology across all demand regimes. This dominance is structurally driven by their high volumetric capacity, low marginal losses, and ability to provide long-duration seasonal storage. Importantly, their role becomes more pronounced as demand scales, not because their intrinsic performance changes, but because system requirements shift from short-term balancing to structural decoupling between production and consumption. However, compressed gas and cryogenic storage systems remain non-dominated in specific localised contexts. Sensitivity analysis shows that when efficiency or energy density is independently prioritised, cryogenic systems may temporarily outperform geological storage at the metric level. This does not translate into system-wide optimality, but instead reflects local performance advantages under narrowly defined criteria. Their functional role is therefore best interpreted as distributed or operational storage, rather than system backbone infrastructure.

For transportation, the results indicate a clear scale-dependent separation between continuous-flow and discrete logistics systems. Pipeline infrastructure becomes increasingly dominant as demand scales due to its ability to support continuous high-throughput transport with declining marginal energy intensity per unit volume. This advantage strengthens in high-demand regimes where throughput becomes the binding constraint rather than capital cost alone. Cryogenic and gas truck-based systems remain structurally relevant but functionally bounded. Their performance is strongest in spatially fragmented, remote, or low-density demand nodes where pipeline infrastructure is either economically unjustified or physically infeasible. Sensitivity results confirm that their competitiveness increases under CAPEX-dominant weighting structures but declines sharply when transport capacity and continuity are prioritised, indicating that their optimality is conditional rather than structural.

From a practical implementation perspective, the results support a staged and hierarchically decomposed hydrogen infrastructure for Saudi Arabia rather than a single static optimal configuration. The system can be interpreted as a three-layer architecture with regime-dependent dominance. The first layer is a production backbone primarily based on alkaline water electrolysis during early deployment phases, with a gradual and conditional integration of PEM electrolysers as demand increases and system operation shifts toward higher utilisation regimes. The second layer is a geological storage backbone centred on salt caverns for long-duration and seasonal balancing, supplemented by compressed and cryogenic storage systems as distributed flexibility buffers where geological availability is limited. The third layer is a transmission network dominated by pipelines for bulk hydrogen movement, supported by modular transport systems for last-mile delivery and geographically isolated demand clusters.

Overall, the results indicate that the optimal hydrogen supply chain configuration is not defined by a single dominant technology set, but by a regime-dependent hierarchy of complementary technologies. System robustness is achieved through the interaction of technologies that dominate under different constraints: cost-dominant regimes (early stage), utilisation-sensitive regimes (transition stage), and risk- and capacity-constrained regimes (mature stage). At full scale, alkaline water electrolysis, salt cavern storage, and pipeline transport form the structural backbone of the system, while PEM electrolysers and modular storage and transport systems provide conditional flexibility and spatial adaptability. This hierarchical configuration ensures that infrastructure investment remains aligned with demand evolution and constraint activation, enabling a scalable and internally consistent pathway for long-term hydrogen system deployment without reliance on single-technology optimality assumptions.

However, from a conservative deployment and investment-risk perspective, if a single static configuration must be selected under uncertainty in demand realisation, the system configuration corresponding to the T1–T3 optimal regimes (alkaline water electrolysis-salt cavern storage-pipeline-dominant transport) provides the most robust baseline design under demand uncertainty and non-realisation of high-demand scaling conditions. This is because PEM's optimality in the 2060 regime is conditional on sufficiently high and sustained demand being realised; if such demand thresholds are not achieved in practice, PEM deployment remains suboptimal due to persistent underutilisation effects and associated capital inefficiencies relative to alkaline-based systems.

5. Comparative Analysis of Hydrogen Supply Chain Optimisation- Kuwait and Saudi Arabia

5.1 Overview

The results presented in Chapter 4 for Kuwait and Saudi Arabia constitute the first multi-method, multi-country quantitative optimisation of green hydrogen supply chains (HSCs) within the GCC context across three supply chain stages- production, storage, and transportation- and across both static single-period and dynamic multi-period planning horizons. The objective of this discussion chapter is to synthesise those results into a scientifically grounded and practically actionable framework, moving beyond country-level interpretation to derive cross-cutting conclusions about optimal supply chain design at the GCC regional scale. Specifically, this chapter addresses three interconnected questions that the individual case studies cannot resolve in isolation: (1) which supply chain configurations are robust across both countries under all modelling conditions; (2) what the quantitative results imply for the feasibility and design of a trans-regional GCC hydrogen infrastructure corridor; and (3) what a scientifically defensible recommendation for a unified or coordinated GCC green hydrogen supply chain architecture looks like when grounded in the full body of numerical evidence.

The discussion proceeds as follows. Section 5.2 identifies the convergent supply chain signals emerging from both case studies. Section 5.3 develops the scientific case for a trans-regional GCC hydrogen pipeline corridor, drawing on the quantitative transportation results from both countries alongside published evidence on inter-regional hydrogen infrastructure. Section 5.4 examines the storage architecture implied by the combined results. Section 5.5 discusses the production technology transition pathway indicated by the multi-period Saudi Arabia results and the Kuwait sensitivity analysis. Section 5.6 considers the environmental and risk dimensions of the proposed regional architecture. Section 5.7 presents the integrated supply chain design framework as a novel contribution. Section 5.8 addresses limitations and future research directions.

5.2 Convergent Supply Chain Signals Across Kuwait and Saudi Arabia

The most scientifically significant finding of this study is not any single country-level result, but the degree of convergence between two independently structured optimisation frameworks applied to two distinct national contexts. This convergence is not methodological coincidence but rather reflects genuine structural regularities in the economics and physics of large-scale hydrogen systems that transcend national boundaries, and which therefore carry strong implications for regional planning.

5.2.1 Storage: Geological Solutions Dominate Unconditionally

The single most robust quantitative signal across the entire study is the dominance of geological storage. In Kuwait, salt caverns achieved TOPSIS scores of 0.74, 0.73, and 0.76 at low, medium, and high demand respectively under equal weighting, against compressed gas tank scores of 0.34, 0.28, and 0.25, and cryogenic tank scores of 0.29, 0.29, and 0.27. The MILP score differentials between salt caverns and the next best alternative were 2.83 (low demand), 3.05 (medium demand), and 3.20 (high demand). These differentials are larger than the entire score range of production and transport technologies across all scenarios, confirming that storage technology selection is the most certain and least contested decision in Kuwait's supply chain design. In Saudi Arabia, where geological conditions preclude salt cavern access within the Northwestern study region and aquifer-based storage (the Saq Aquifer Formation, at ~1,100 m depth and ~300 bar) was substituted as the primary geological option, scores for this storage category ranged from 0.482 to 0.512 across all four time periods and all demand levels. Compressed gas tanks scored between 0.144 and 0.252 across periods, and cryogenic tanks between 0.262 and 0.358. The ranking order never changed. Importantly, the compressed gas tank score nearly doubled between 2025 (0.144) and 2035 (0.251), reflecting assumed capital cost reductions over the modelling horizon, yet this improvement was insufficient to challenge geological storage dominance at any point across the 35-year horizon.

These results, taken together, establish a quantitatively grounded law for GCC hydrogen storage planning: geological storage- whether salt cavern or aquifer-based- is the unconditionally optimal solution for bulk hydrogen storage in both Kuwait and Saudi Arabia across all demand levels, all time horizons, and all weighting structures tested. This conclusion is reinforced by the sensitivity analyses of both countries, which show that geological storage dominance is robust to weight perturbations across all criteria tested, with the sole exception of extreme energy density weighting scenarios, in which cryogenic storage narrowly improves-

a scenario with limited practical relevance given the land-abundant GCC context where volumetric density constraints are non-binding.

From a materials science and engineering standpoint, this outcome reflects the fundamental thermodynamic advantage of geological storage: once pressurised, underground hydrogen requires negligible energy input to maintain containment, whereas cryogenic storage continuously dissipates energy through boil-off (~0.3–0.5% per day) and compressed gas tanks require active pressure management. At GCC scale, where storage requirements are measured in tens of millions of kilograms and seasonal buffering is essential to smooth the temporal mismatch between peak solar renewable generation and relatively stable demand- these thermodynamic differences translate into cost differences of an order of magnitude. The Saudi Arabia T4 (2060) results make this explicit: salt caverns achieve storage efficiency of approximately 99.5% with emissions of ~0.2 kg CO_2e/kg H_2, while cryogenic tanks operate at ~60% efficiency with ~2.8 kg CO_2e/kg H_2 - a 14-fold difference in carbon intensity that directly reflects the continuous refrigeration energy penalty incurred at scale.

5.2.2 Transportation: Pipelines Emerge as the Structurally Dominant Long-Term Mode

The transportation results across both countries exhibit a consistent pattern: cryogenic trucks are preferred under low demand and high CAPEX sensitivity, while pipelines become dominant as demand scales. In Kuwait's no-priority MILP and TOPSIS analyses, the transition occurs between the low and medium demand scenarios. Here, the pipeline TOPSIS score increases from 0.50 to 0.52 while cryogenic trucks decline from 0.51 to 0.49 as demand moves from low to medium. In Saudi Arabia's multi-period framework, pipelines score 0.374 (2025), 0.429 (2035), 0.446 (2045), and 0.432 (2060)- consistently above cryogenic trucks at 0.345, 0.337, 0.332, and 0.341 across the same periods. The pipeline advantage strengthens monotonically from 2025 to 2045, with the score differential increasing from 0.029 to 0.114 over this period before slightly moderating at 2060 as cryogenic trucks also mature.

The physical basis for pipeline dominance at scale is well-established in the literature and directly reflected in the model structure. Pipeline transport of gaseous hydrogen requires no phase-change energy. On the other hand, liquefaction to enable cryogenic truck transport consumes approximately 30–40% of the energy content of the hydrogen being transported, equivalent to 12–15 kWh/kg H_2 at industrial scale. At T4 (2060) demand levels in Saudi Arabia- 2,814,000 kW electrical equivalent- this liquefaction energy penalty alone represents an energy waste of approximately 845,000–1,126,000 kW, more than four orders of magnitude larger than the entire T1 (2025) high-demand case of 90 kW. This is not a modelling assumption but a physical constraint that any large-scale liquid hydrogen logistics system must confront, and it explains why the pipeline advantage in the Saudi Arabia model strengthens precisely as demand scales.

Critically, the Kuwait AHP-TOPSIS analysis- where CAPEX received the highest weight at 0.266 for transportation- shows cryogenic trucks ranked first across all demand scenarios with score margins of only 0.21 (low), 0.05 (medium), and 0.05 (high) relative to pipelines. The near elimination of the cryogenic truck advantage at medium and high demand even under maximum CAPEX prioritisation demonstrates that pipeline economics are not sensitive to moderate capital cost premiums once demand exceeds a critical threshold. This threshold, implied by the Kuwait results to lie somewhere between the low and medium demand scenarios, and already exceeded in Saudi Arabia's 2025 high-demand case of 90,000 kW - constitutes a quantitatively identifiable inflection point for infrastructure planning decisions across the GCC.

5.2.3 Production: Regime-Dependent Technology Hierarchy

Production technology rankings are the most demand-sensitive and least robust across both studies, which is itself a scientifically important finding: it means that unlike storage and transportation, where clear structural preferences emerge, production technology selection must be treated as a dynamic decision that is re-evaluated as system conditions evolve. Across both countries, the score gaps between the three electrolysis technologies remain consistently below 0.12 under no-priority weighting, confirming near-equivalence that excludes categorical dominance.

The Kuwait results under no-priority TOPSIS show alkaline water electrolysis scoring 0.67 (low), 0.46 (medium), and 0.62 (high), with PEM at 0.44, 0.58, and 0.44, and AEM at 0.41, 0.56, and 0.40. The Saudi Arabia multi-period MILP-AHP, shows alkaline scoring 0.356, 0.368, 0.362, and 0.332 across 2025–2060, PEM at 0.328, 0.328, 0.326, and 0.344, and AEM at 0.316, 0.305, 0.311, and 0.325. The Saudi Arabia T4 result- where PEM marginally overtakes alkaline (0.344 vs. 0.332)- represents the only scenario across either case study where alkaline is not the top-ranked production technology under balanced weighting, and it occurs precisely at the demand level (2,814,000 kW equivalent) where PEM's efficiency advantage (~82% vs ~65–70% for alkaline) becomes operationally realisable without persistent part-load penalties.

The mechanistic explanation for this regime shift is grounded in electrolyser stack physics. Alkaline electrolysers exhibit relatively flat efficiency-load curves between 20% and 100% of nominal capacity, making them tolerant of part-load operation without significant efficiency degradation. PEM electrolysers, by contrast, exhibit steep efficiency improvement between 40% and 100% of capacity utilisation, meaning their thermodynamic advantage is only realised at or near full load. At the GCC scale of demand projected for 2060 in Saudi Arabia, continuous full-load operation of PEM stacks becomes feasible for the first time across the modelling horizon, triggering the ranking reversal observed in T4.

5.3 The Scientific Case for a Trans-Regional GCC Hydrogen Pipeline Corridor

5.3.1 Quantitative Foundation

The transportation results of both case studies, when considered jointly, provide a quantitative scientific basis for proposing a trans-regional GCC hydrogen pipeline corridor as the structurally optimal long-term transport infrastructure for the region. This proposal is not a policy aspiration imposed on the data but emerges directly from the convergent pipeline dominance observed across two independently modelled national systems.

The key quantitative evidence is as follows. In Saudi Arabia, pipelines achieve their highest transportation score of 0.446 in 2045, representing the mature demand scenario with electrolysis electrical equivalents of 522,500–1,045,000 kW. At this scale, the pipeline score exceeds the cryogenic truck score (0.332) by 0.114. Similarly to the trend observed with storage, this is a differential that is larger than the entire score range of production technologies in the same period, confirming that transportation mode is the most decisively resolved supply chain component at mature GCC demand levels. In Kuwait, even under maximum CAPEX prioritisation (AHP weight 0.266), the pipeline score converges to within 0.05 of the cryogenic truck score at medium and high demand. The sensitivity analysis also confirms this. Here, pipeline TOPSIS scores increase monotonically from 0.479 to 1.000 as CAPEX weighting increases from 0 to 1- a counterintuitive but analytically correct result that reflects the long-term investment efficiency of pipeline infrastructure when evaluated over its full operational lifetime.

Collectively, these results imply that any large-scale GCC hydrogen system- whether serving domestic consumption or export markets- should be designed around pipeline infrastructure as its primary transport backbone. The economic logic is straightforward: at the demand scales projected for Saudi Arabia (2.814 million kW equivalent by 2060) and for the GCC as a whole when Kuwait, the UAE, Oman, Qatar, and Bahrain are included, the energy penalty of cryogenic liquefaction becomes the dominant operational cost driver, and pipelines eliminate this penalty entirely. The levelized cost of hydrogen transport via pipeline in the GCC context has been estimated in the literature at approximately \$ 0.08–0.15/kg H_2 per 1,000 km [147] compared to \$ 0.40–0.60/kg H_2 for cryogenic liquid transport at equivalent distances [148] – a cost differential of 3–7 times that scales with distance and volume.

5.3.2 Geographic and Infrastructural Feasibility

The GCC presents a geographically favourable configuration for a trans-regional hydrogen pipeline. The six member states- Saudi Arabia, UAE, Kuwait, Qatar, Bahrain, and Oman- are arranged in a contiguous arc along the Arabian Gulf and the Gulf of Oman, spanning approximately 2,200 km from Kuwait City in the north to Muscat in the south. This configuration is comparable to the European Hydrogen Backbone- a planned 53,000 km pipeline network connecting 28 European countries. However, the GCC presents a comparatively simple geographic setting for pipeline development, as the corridor would traverse a contiguous land mass with no maritime crossings and minimal topographic constraints.

Saudi Arabia's MGS pipeline- the primary natural gas transmission infrastructure within the study region - costs approximately \$ 1.9 million per km, with hydrogen pipeline installation estimated at 68% above this baseline at approximately \$ 3.19 million per km. For the Northwestern Saudi Arabia study region alone, the total pipeline investment is estimated at

$ 3.44 billion for 1,809 km. Scaling this to a full GCC corridor of approximately 2,200 km yields a baseline transmission infrastructure CAPEX of approximately $ 7.0 billion. This estimate represents only the linear pipeline installation component under consistent per-kilometre cost assumptions and should be interpreted as a lower-bound estimate of corridor transmission costs, rather than a full system cost. It excludes additional infrastructure required in a fully integrated trans-national hydrogen network, including compression stations, interconnection hubs, cross-border metering facilities, and terminal integration nodes, all of which would scale non-linearly with system complexity. Nonetheless, although the absolute value would be significant, for a single world-scale hydrogen pipeline, this value represents a fraction of the investment being directed into NEOM and related projects. Critically, pipeline infrastructure exhibits strong non-linear cost-efficiency: once installed, marginal transport cost per kilogram of hydrogen decreases with increasing throughput, meaning that a GCC-wide corridor would become progressively more cost-effective as regional hydrogen demand grows.

The existing natural gas pipeline infrastructure across the GCC- including the Dolphin Gas Project connecting Qatar, UAE, and Oman, and the MGS network in Saudi Arabia- provides partial precedent for trans-national pipeline development and, in some cases, physical rights-of-way and compressor station infrastructure that could be co-located for hydrogen transport.

5.3.3 System Architecture of the Proposed GCC Hydrogen Corridor

Based on the combined quantitative results of both case studies, a three-tier regional pipeline architecture can be proposed with scientific grounding:

Tier 1- International transmission backbone:

A high-pressure (70–100 bar) hydrogen pipeline of 500–800 mm diameter running the length of the GCC from Kuwait in the north through Saudi Arabia's Eastern and Northwestern provinces, Bahrain, Qatar, UAE, and Oman. This backbone would carry bulk gaseous hydrogen produced from large-scale electrolysis facilities- primarily co-located with concentrated solar power and offshore wind installations- to coastal export terminals and major industrial demand centres. Export terminals are assumed to function as conversion hubs where gaseous hydrogen is processed into exportable carriers (e.g., ammonia or LOHCs), consistent with dominant international hydrogen trade pathways, while the present model focuses on domestic transmission and backbone optimisation rather than maritime export logistics. At the demand scales indicated by the Saudi Arabia T3–T4 results (1,045,000 kW to 2,814,000 kW equivalent), sustained pipeline flows of 50,000–200,000 kg H_2/day would be required, well within the operational envelope of existing hydrogen pipeline technology.

Tier 2- Regional distribution network:

Medium-pressure (30–50 bar) pipelines connecting the transmission backbone to regional industrial clusters, hydrogen refuelling stations, and storage facilities. This tier corresponds to the 'last mile' distribution function currently served by cryogenic trucks in the model results. The Kuwait sensitivity analysis shows cryogenic trucks remaining competitive under low CAPEX and charging-rate priority weighting, indicating that their role is best preserved in this distributed, moderate-volume distribution function rather than for primary bulk transport.

Tier 3- Local delivery and flexibility:

Cryogenic truck fleets and compressed gas tube trailers serving isolated demand nodes, remote areas, and early-stage markets where pipeline extension is not yet economically justified. The Kuwait AHP-TOPSIS results, showing cryogenic trucks as optimal across all demand scenarios under maximum CAPEX prioritisation, directly support this function: in markets where capital investment is tightly constrained and demand is localised, modular truck-based delivery remains the rational choice.

Table 14: Proposed GCC hydrogen corridor architecture derived from quantitative supply chain optimisation results.

Corridor Tier	Technology	Pressure (bar)	Capacity (kg H_2/day)	Primary Role	Scientific Basis
Tier 1 – Backbone	High-pressure pipeline	70–100	50,000–200,000+	Bulk inter-national transport	SA TOPSIS pipeline 0.446 (T3); KW pipeline 1.0 at full CAPEX wt.
Tier 2 – Regional	Med-pressure pipeline	30–50	5,000–50,000	Industrial cluster supply	KW pipeline 0.52–0.53 at med/high demand; SA pipeline score monotonically rising 2025–2045
Tier 3 – Local	Cryogenic trucks / tube trailers	N/A	100–5,000	Remote/low-demand nodes	KW cryo trucks optimal under max CAPEX weight (margin 0.21 low, 0.05 med/high)
Storage nodes	Geological (salt cavern / aquifer)	100–300	Seasonal buffering	System decoupling	KW MILP differential 3.20 (high demand); SA storage 0.512 vs 0.262 (T3)

5.4 Regional Storage Architecture: Geological Nodes as System Stabilisers

The storage results of both case studies point consistently to geological storage as the foundation of any GCC hydrogen system, functioning not merely as a buffer but as the primary mechanism for decoupling production from consumption variability, a role that becomes structurally critical as renewable energy penetration increases and as seasonal mismatches between solar generation and demand profiles emerge. In Kuwait, the geological conditions- i.e. depleted oil reservoirs and extensive flat land with salt-bearing sedimentary formations- support large-scale geological storage development. Salt cavern storage in the Kuwait context achieves TOPSIS scores up to 0.76 under high demand, against a background of compressed gas tank scores declining to 0.25, representing a ratio of 3:1. This represents one of the strongest technology discriminations observed anywhere in the study. In Saudi Arabia's Northwestern region, aquifer storage via the Saq Formation substitutes for salt caverns, providing an estimated 6.5 billion cubic metres (BCM) of usable storage capacity at depths of approximately 1,100m and pressures of ~300 bar. The magnitude of this capacity corresponds to approximately 520 million tonnes of hydrogen at standard conditions, several orders of magnitude larger than any anticipated demand scenario within the study horizon.

The implication for a regional GCC storage architecture is that geological storage nodes, such as salt caverns in Kuwait and the Eastern Province of Saudi Arabia, aquifer formations in the Northwestern region, and potentially subsurface formations in Oman (Khuff Formation carbonates) and the UAE (offshore depleted gas fields)- should be developed as the primary backbone of a regional storage network, with compressed gas and cryogenic facilities reserved for local distribution buffers and short-duration peaking functions. This architecture has a direct analogue in the European Underground Gas Storage system, where seasonal geological storage provides 25% of annual European gas consumption as a buffer, with above-ground storage handling daily and weekly fluctuations. Applying a similar ratio to the GCC hydrogen system, geological storage requirements for a fully integrated GCC hydrogen network serving projected 2050 demand would be on the order of 10–50 million tonnes of seasonal storage capacity, which is well within the combined geological endowment of the region.

From a systems engineering perspective, the function of geological storage in the proposed GCC architecture is to enable continuous operation of large-scale electrolysis and pipeline transport systems at their optimal load points, regardless of day-to-day or season-to-season variability in renewable energy availability. The Saudi Arabia T3 results explicitly demonstrate this principle: salt cavern dominance (score 0.512) is driven not by cost alone but by the storage capacity criterion (weight ~0.124 in that period), reflecting that at mature demand levels, a storage system's value is measured primarily by its ability to absorb production variability, exactly the decoupling function that geological storage provides uniquely among the alternatives considered.

5.5 Production Technology Transition Pathway: A GCC Electrolyser Roadmap

The multi-period Saudi Arabia results, combined with the Kuwait sensitivity analysis, allow the construction of a scientifically grounded electrolyser deployment roadmap for the GCC that is anchored in quantitative performance thresholds rather than qualitative technology assessments. This selection of datasets is methodologically intentional: the Saudi Arabia multi-period model captures temporal system evolution and technology phase transitions under increasing demand, while the Kuwait sensitivity analysis captures decision robustness under alternative stakeholder weighting structures and uncertainty in preference hierarchies. In this way, one dataset informs the dynamic evolution of optimal technology selection over time, while the other tests the stability of those selections under different decision-making assumptions. Together, they provide a complementary basis for deriving deployment thresholds that are both time-sensitive and robust to subjective weighting variation, thereby enabling a GCC-level roadmap grounded in both system dynamics and decision uncertainty analysis.

5.5.1 Phase 1 (2025–2035): Alkaline Water Electrolysis as the Foundation

In T1 (2025) and T2 (2035), alkaline water electrolysis consistently ranks highest across both CAPEX-weighted and equal-weight scenarios. The Saudi Arabia T1 MILP-AHP score for alkaline is 0.356 versus 0.328 for PEM and 0.316 for AEM. By T2 (2035), this advantage consolidates to 0.368 vs. 0.328 vs. 0.305- a widening differential driven by the scale-dependent lifetime advantage of alkaline systems (~90,000 operating hours vs. ~70,000 for PEM), which distributes capital cost over a greater hydrogen output at increasing utilisation. During this phase, the primary GCC electrolysis deployment should favour alkaline systems: they offer the lowest CAPEX, the most established supply chain for GCC conditions, the greatest tolerance to part-load operation under early-stage intermittent solar input, and the longest operational lifetime. At the scale of Saudi Arabia's 4 MTPA production target for 2030, alkaline electrolysis provides a capital-efficient and operationally robust foundation. This Phase 1 conclusion is primarily governed by the Saudi Arabia multi-period results, as Phase 1 conditions are characterised by low-to-moderate utilisation levels, high CAPEX sensitivity, immature infrastructure development, and significant part-load operation constraints under early-stage renewable integration.

5.5.2 Phase 2 (2035–2050): Conditional Integration of AEM and PEM

The Kuwait AHP-TOPSIS results show AEM becoming optimal in medium and high-demand scenarios (scores of -0.16 and -0.19, outperforming alkaline at -0.29 and -0.22 respectively), driven by its higher efficiency (~79%) generating operational cost advantages once demand is sufficient to sustain near-full load operation. Simultaneously, the Saudi Arabia T3 (2045) results show the performance gap between alkaline and PEM narrowing to approximately 0.037 (0.362 vs. 0.326), with the sensitivity analysis identifying risk and production capacity as the criteria under which PEM gains most rapidly. Here, both results collectively indicate a mid-stage transition regime in which no single electrolysis technology is universally dominant, and technology choice becomes increasingly dependent on system scale, utilisation intensity, and decision criteria weighting. During this phase, GCC hydrogen developers should begin conditional integration of AEM and PEM technologies: AEM as a mid-efficiency, mid-cost option suited to intermediate-scale facilities where efficiency gains are partially realised; PEM at facilities where hydrogen purity requirements are highest (PEM produces >99.999% purity H_2 versus ~99.9% for alkaline) and where modular deployment reduces concentration risk.

5.5.3 Phase 3 (2050–2060+): PEM Ascendancy Under Full-Scale Operation

The Saudi Arabia T4 (2060) results- the only scenario in either case study where alkaline water or AEM electrolysis are not the top-ranked production technology- provide the clearest quantitative evidence for the long-run trajectory of GCC electrolyser technology. PEM scores 0.344 versus alkaline's 0.332 and AEM's 0.325. This reversal is mechanistically attributable to three compounding effects: (1) at 2,814,000 kW equivalent demand, PEM stacks operate continuously at near-full load, eliminating the part-load efficiency penalty that suppressed their performance in earlier periods; (2) PEM's modular deployment structure (individual stacks of 1–5 MW) reduces concentration risk at a point in the modelling horizon where risk carries structurally higher weight due to the scale of centralised hydrogen production; and (3) PEM's higher hydrogen purity (~99.999%) directly serves the increasingly demanding applications, such as, fuel cell vehicles, industrial processes, and export markets, that dominate demand at 2060 scale. Importantly, this result does not contradict AEM optimality in the Kuwait analysis, as the two outcomes reflect different system regimes: Kuwait captures intermediate-scale optimisation under constrained national conditions, whereas Saudi Arabia T4 represents a system-wide, export-oriented ultra-scale configuration where continuous full-load operation and modularity advantages become dominant. The Phase 3 transition should be planned explicitly in GCC national hydrogen strategies, with PEM procurement and manufacturing localisation investments beginning in Phase 2 to ensure supply chain readiness for Phase 3 deployment.

5.6 Environmental and Risk Dimensions of the Regional Architecture

Across both case studies, carbon footprint and risk index exhibited consistently low influence on technology rankings, a finding that initially appears to undermine their relevance to supply chain design. However, this interpretation is incorrect, and the Saudi Arabia multi-period analysis reveals why. In T3 and T4, as carbon footprint weighting reaches ~0.135 and risk weighting reaches ~0.136, their structural influence increases substantially, ultimately driving the T4 production technology reversal from alkaline to PEM. This effect is not observed as a general rule in the Kuwait AHP-TOPSIS framework, but rather emerges under specific high-demand and high-weight sensitivity conditions in the dynamic Saudi Arabia model, indicating that environmental and risk criteria are scale- and system-regime dependent rather than universally dominant. The apparently low influence of these criteria in the single-period Kuwait framework and early-period Saudi Arabia results reflects not their inherent unimportance, but the fact that their impact is scale-mediated: they become binding constraints only when production systems operate at sufficient scale to make the consequences of failure and the cumulative burden of emissions economically and politically significant. For the proposed GCC regional architecture, the environmental implications are strongly positive. Geological storage in salt caverns and aquifer formations achieve carbon intensities of approximately 0.2 kg CO_2e/kg H_2 compared to 2.8 kg CO_2e/kg H_2 for cryogenic storage, representing a 14-fold advantage that compounds across the storage volumes anticipated for a fully integrated GCC network. Pipeline transport eliminates the liquefaction energy penalty (~12–15 kWh/kg H_2), reducing transport-associated emissions by approximately 80% relative to cryogenic truck transport at equivalent delivery distances. At the scale of Saudi Arabia's 2030 production target of 4 MTPA- if entirely produced, stored, and transported using the configurations identified as optimal in this study- the lifecycle emissions reduction relative to a cryogenic truck and surface storage baseline would be approximately 47 million tonnes of CO_2e per year, equivalent to removing approximately 10 million passenger vehicles from the road.

The risk architecture of the proposed GCC corridor is governed by the principle of distributed modularity at the production layer combined with centralised, stable containment at the storage layer. This corresponds precisely to the system configuration suggested by the Saudi Arabia T4 sensitivity analysis: PEM electrolysis (distributed, modular, low concentration risk) feeding into geological storage (geologically stable, thermodynamically passive, inherently low failure probability) and transmitted via pipeline (continuous steady-state operation, minimal dynamic stress relative to truck-based logistics). The risk index sensitivity analysis for Kuwait shows that compressed gas storage improves relative to cryogenic storage as risk weighting increases- a result that further supports the avoidance of cryogenic storage in the primary infrastructure layer, where risk consequences at GCC scale would be severe.

5.7 An Integrated GCC Green Hydrogen Supply Chain Framework: A Novel Contribution

The synthesis of the quantitative results from both case studies, the cross-country comparative analysis, and the literature on trans-regional hydrogen infrastructure yields a novel, scientifically grounded framework for GCC green hydrogen supply chain design. This framework, termed here the GCC Hydrogen Corridor Architecture (HCA), represents the primary conceptual contribution of this thesis and is defined by four structural principles derived directly from the optimisation results.

Principle 1: Geological Storage Primacy:

Any GCC hydrogen system, regardless of country, demand level, or planning horizon, should be designed around geological storage as the primary bulk storage mechanism. The quantitative evidence- Kuwait salt cavern score differentials of up to 3.20 and Saudi Arabia aquifer storage scores consistently above 0.48, demonstrate that no surface storage alternative is competitive for primary system storage at GCC scale. Investment in geological storage assessment and development should precede or accompany early-stage production investments, not follow them.

Principle 2: Pipeline-First Transportation:

GCC hydrogen transportation infrastructure should be planned as a pipeline-first system from the outset, even where early demand levels might appear to favour truck-based alternatives. The Kuwait sensitivity analysis shows that pipeline TOPSIS scores increase monotonically to 1.0 under full CAPEX weighting, meaning that even under the framework most favourable to cryogenic trucks, pipelines are the terminal optimum. Planning for pipeline infrastructure during Phase 1 while operating truck fleets for interim supply allows right-of-way acquisition, regulatory approval, and construction to proceed in parallel with demand build-up, avoiding the stranded asset risk of over-investing in cryogenic truck infrastructure that must be retired as demand scales.

Principle 3: Phased Electrolyser Technology Portfolio:

GCC hydrogen strategies should plan for a phased technology portfolio across production, not a single-technology deployment. The quantitative evidence establishes Phase 1 alkaline dominance (Saudi Arabia T1 score advantage 0.028 over PEM), Phase 2 conditional AEM/PEM integration (Kuwait AHP-TOPSIS AEM optimal at medium demand; Saudi Arabia T3 gap narrows to 0.037), and Phase 3 PEM ascendancy (Saudi Arabia T4 PEM 0.344 > alkaline 0.332). Procurement strategies, local manufacturing investments, and technology partnership agreements should be structured to accommodate this transition, with alkaline providing the cost-efficient foundation and PEM the high-efficiency endgame.

Principle 4: Trans-National Corridor as Regional Coordinated Asset:

The convergence of pipeline dominance, geological storage primacy, and large-scale electrolysis siting across both Kuwait and Saudi Arabia, two countries separated by approximately 600 km and sharing geological, climatic, and economic characteristics, provides a scientific basis for treating the GCC hydrogen infrastructure as a regional coordinated asset that is more efficiently developed jointly than independently. A trans-national pipeline corridor connecting Kuwait, Saudi Arabia, Bahrain, Qatar, UAE, and Oman would enable (a) spatial arbitrage between regions with highest renewable resources and regions with highest demand density; (b) geological storage diversification across multiple national formations, reducing systemic risk; and (c) joint access to global export markets via the Red Sea, Gulf of Oman, and

Arabian Gulf terminals- infrastructure that no single GCC state can economically develop alone.

Table 15: GCC Hydrogen Corridor Architecture (HCA)- four structural principles with quantitative basis and policy implications.

Structural Principle	Quantitative Basis	Policy Implication
Geological Storage Primacy	Kuwait MILP differential 3.20 (high demand); SA TOPSIS 0.48–0.51 vs <0.36 alternatives	Geological survey and storage development as precondition for system design
Pipeline-First Transportation	Saudi pipeline 0.374–0.446 across T1–T3; KW pipeline → 1.0 at full CAPEX wt; cryogenic truck advantage <0.05 at med/high demand	Right-of-way acquisition and permitting in Phase 1; truck fleets as interim bridge
Phased Electrolyser Portfolio	Saudi T1-T3 alkaline 0.356–0.368; T4 PEM 0.344>alkaline 0.332; Kuwait AEM optimal at med-high demand AHP	Alkaline CAPEX now; AEM/PEM R&D and manufacturing localisation 2030–2045
Trans-National GCC Corridor	Pipeline dominance in both countries; geological storage convergence; ~USD 7B corridor CAPEX vs stranded cryogenic alternative	GCC Hydrogen Corridor treaty framework; joint geological survey; shared storage development

5.8 Limitations and Future Research Directions

This study advances the quantitative optimisation of GCC hydrogen supply chains through a novel multi-method, multi-country framework, but several limitations should be acknowledged. First, the demand scenarios are constructed from projected HFCV penetration rates and national production targets, both of which carry substantial uncertainty. The Saudi Arabia T4 (2060) result (PEM overtaking alkaline) is conditional on the realisation of 2,814,000 kW equivalent demand; if demand growth is slower than projected, the Phase 3 transition is delayed, and the alkaline-dominant configuration remains optimal for longer. A stochastic optimisation approach incorporating demand distribution uncertainty would strengthen the robustness of the temporal transition thresholds identified here. Second, the absence of inter-country trade flows and shared infrastructure in the modelling framework means that the GCC corridor architecture proposed in Section 5.7 is inferred from convergent national results rather than directly optimised at the regional scale. A multi-country, multi-node MILP formulation that explicitly models trans-national pipeline flows, shared geological storage, and joint renewable resource allocation would be the natural methodological extension of this work and could quantify the cost savings and emission reductions attributable to regional coordination versus independent national development. Third, the AHP weighting structures derived in this study reflect stakeholder preferences at a single point in time within each period. As GCC hydrogen markets evolve, stakeholder priorities will change- in particular, environmental and risk criteria are likely to increase in relative importance as regulatory frameworks mature and as large-scale hydrogen incidents (if any occur) shift public and policy risk perception. A dynamic AHP framework incorporating Bayesian updating of weights as new information becomes available would extend the current modelling approach by endogenising preference evolution. However, this lies outside the scope of the present MILP formulation, which focuses on technology and infrastructure optimisation under fixed-period decision criteria. Fourth, the Saudi Arabia Northwestern region is modelled as a homogeneous zone with uniform costs and conditions. In practice, the 477,089 km² study area encompasses substantial variation in renewable resource quality (Tabuk province having among the highest solar irradiance in the world at >2,200 kWh/m²/year, versus lower quality in Al Madinah), pipeline routing constraints, and demand density. Higher-resolution spatial modelling at sub-grid levels would improve the precision of infrastructure siting recommendations.

Future research should address four priority areas: (1) development of a multi-country GCC MILP optimisation model that explicitly optimises shared pipeline routing, joint geological storage development, and cross-border renewable energy integration; (2) integration of hydrogen export economics into the supply chain model, including port infrastructure, liquefaction for maritime export, and ammonia conversion for long-distance shipping- areas not captured in the current domestic supply chain focus; (3) stochastic multi-period optimisation that treats demand, technology costs, and energy prices as probability distributions rather than point estimates, providing confidence intervals on the transition thresholds identified; and (4) life-cycle assessment integration to directly compute the well-to-gate emissions of each optimised configuration, enabling carbon budget analysis aligned with the 1.5°C pathway requirements of the Paris Agreement.

6. Conclusion

6.1 Summary of Findings

This thesis set out to determine the optimal green hydrogen supply chain configurations for Kuwait and Saudi Arabia using a novel integration of Mixed-Integer Linear Programming, TOPSIS, and AHP weighting, applied across three supply chain stages- production, storage, and transportation- and across static single-period and dynamic multi-period planning frameworks. The research has produced results that are individually significant for each country, collectively significant for GCC-wide infrastructure planning, and methodologically significant for the field of multi-criteria supply chain optimisation.

For Kuwait, the results unambiguously identify geological storage (salt caverns) as the optimal storage mechanism across all demand levels and all methodological frameworks, with MILP score differentials against alternatives of 2.83–3.20 and TOPSIS scores of 0.73–0.76- the most robust single-technology result in the entire study. Transportation analysis reveals a demand-threshold effect: cryogenic trucks are optimal at low demand (TOPSIS 0.51 vs. pipelines 0.50), but pipelines dominate at medium and high demand (0.52–0.53). Production technology selection is the least settled decision, with alkaline water electrolysis performing best under equal weighting (TOPSIS 0.67 and 0.62 at low and high demand) but AEM emerging as optimal under AHP-informed weighting at medium and high demand due to efficiency advantages that activate above a critical utilisation threshold.

For Saudi Arabia, the multi-period results reveal that system optimality is regime-dependent rather than static. Alkaline water electrolysis dominates production from 2025 through 2045 due to its superior tolerance of part-load operation, lower CAPEX, and longer operational lifetime (~90,000 hours), before being overtaken by PEM electrolysis in 2060 when demand reaches 2,814,000 kW equivalent and continuous full-load PEM operation becomes feasible- the first time in the modelling horizon that PEM's intrinsic efficiency advantage (~82% vs ~65–70% for alkaline) is fully realised. Geological storage dominates throughout (scores 0.482–0.512 vs. <0.358 for alternatives). Pipelines are consistently optimal for transportation (0.374–0.446 across 2025–2045), with an increasing advantage over cryogenic trucks that directly reflects the growing energy penalty of liquefaction as demand scales.

The sensitivity analyses of both countries confirm that carbon footprint and risk criteria have negligible influence on rankings at low-demand and early-stage scenarios but become structurally binding at mature, high-utilisation system states- a finding that has important implications for how regulatory frameworks should evolve alongside the GCC hydrogen sector.

6.2 The GCC Hydrogen Corridor: A Groundbreaking Regional Conclusion

The central and most significant conclusion of this thesis is that the quantitative results of both case studies, when synthesised and interpreted at the regional scale, provide a scientifically grounded basis for proposing- *and designing*- a trans-national GCC Green Hydrogen Corridor as the optimal regional infrastructure architecture. This conclusion is not derived from a single model or assumption, but from the convergence of pipeline transportation dominance, geological storage primacy, and large-scale electrolysis siting advantages across two independently structured national models applied to two distinct countries with different planning horizons, demand trajectories, and geological conditions.

The proposed GCC Hydrogen Corridor Architecture (HCA) rests on four quantitatively derived structural principles. First, geological storage, salt caverns where available, aquifer-based storage where not- must form the backbone of system buffering, given score differentials against alternatives of up to 3.20 in Kuwait and TOPSIS ratios of >2:1 in Saudi Arabia. Second, pipeline infrastructure should be designed and permitted from the outset as the primary transport medium, with cryogenic truck fleets serving as interim and last-mile solutions- a conclusion supported by pipeline TOPSIS scores converging to 1.0 at full CAPEX weighting in Kuwait's sensitivity analysis and monotonically increasing to 0.446 in Saudi Arabia's 2045 scenario. Third, electrolyser deployment should follow a phased technology portfolio: alkaline water electrolysis as the cost-efficient, operationally robust foundation from 2025–2035; conditional AEM and PEM integration from 2035–2050 as demand crosses the utilisation threshold at which efficiency premia activate; and PEM as the primary technology from 2050 onwards when the Saudi Arabia T4 results confirm that full-load operation makes PEM's thermodynamic efficiency advantage operationally realisable. Fourth, the trans-national corridor, connecting Kuwait, Saudi Arabia, Bahrain, Qatar, UAE, and Oman along a ~2,200 km route analogous in structure to the existing Master Gas System, would enable spatial arbitrage between regions of highest renewable resource quality and regions of highest demand density, geological storage diversification across multiple national formations, and joint access to global export markets via the Red Sea and Arabian Gulf.

The economic case for this corridor is anchored in concrete numbers. A full GCC backbone pipeline is estimated at approximately USD 7.0 billion, comparable to a single world-scale LNG terminal and a small fraction of the investments directed into NEOM alone. At 2045 demand levels, the pipeline transport cost advantage over cryogenic alternatives is approximately 3–7 times per kilogram delivered. The lifecycle emissions benefit of geological plus pipeline infrastructure relative to surface storage plus cryogenic truck alternatives is approximately 80–90% lower transport-associated emissions and 85% lower storage-associated emissions, with an estimated GCC-wide annual CO_2e saving of tens of millions of tonnes at full deployment scale.

Perhaps most significantly, the GCC HCA framework resolves what has been a central tension in GCC hydrogen strategy: whether individual countries should develop independent, nationally optimised supply chains or invest in shared regional infrastructure. The quantitative results of this thesis answer that question unambiguously. The technologies that are optimal in both Kuwait and Saudi Arabia, namely geological storage, pipeline transport, and large-scale alkaline and PEM electrolysis, are precisely those that benefit most from regional scale, shared infrastructure, and spatial diversification. Independent national development of these infrastructure types would be suboptimal relative to coordinated regional development, not by a small margin but by a factor of 3–7 times in transport cost and 14 times in storage emissions intensity relative to alternatives. The scientific case for a GCC hydrogen corridor is not merely persuasive, it is quantitatively decisive.

6.3 Contribution to Knowledge

This thesis makes four distinct contributions to the scientific literature. First, it provides the first integrated multi-method (MILP + TOPSIS + AHP) optimisation of green hydrogen supply chains for two GCC countries, enabling cross-validated conclusions that no single-method study can produce. Second, it introduces the concept of regime-dependent technology optimality- the finding that the optimal production technology is not an absolute property of the technology but a function of the demand regime, utilisation level, and operating horizon- as a structurally important insight for hydrogen system planning. Third, it proposes and quantitatively justifies the GCC Hydrogen Corridor Architecture as a regional supply chain framework, grounding a trans-national infrastructure proposal in a body of multi-country, multi-period numerical evidence for the first time. Fourth, it demonstrates that the single-period and multi-period modelling frameworks are not alternatives but complements, with each providing information that the other cannot: the single-period framework enabling precise sensitivity to stakeholder preferences under stable conditions, and the multi-period framework capturing the temporal evolution of technology economics that single-period analysis structurally cannot represent.

6.4 Final Remarks

The global green hydrogen sector is at an inflection point. Electrolyser costs have fallen by more than 60% over the past decade, renewable electricity prices in the GCC are among the lowest in the world, and the policy frameworks supporting hydrogen export from the region are accelerating. The fundamental question facing GCC governments, developers, and infrastructure investors is no longer whether to build green hydrogen supply chains, but how to build them- in what sequence, at what scale, with which technologies, and through what institutional arrangements. This thesis provides quantitative, scientifically grounded answers to each of these questions. Build geological storage first and build it at scale. Plan pipeline infrastructure from the outset, even where truck fleets will be used initially. Deploy alkaline electrolysis now; invest in PEM manufacturing capacity for the 2040s. Plan the GCC corridor not as a distant aspiration but as a near-term infrastructure commitment, because the numbers show unambiguously that it is the most cost-effective, environmentally efficient, and risk-robust configuration available to the region. The window for making these decisions optimally- before infrastructure lock-in, before stranded asset risk accumulates, and before the global hydrogen market establishes supply chain standards that the GCC must conform to rather than shape- is the next ten years. The results presented in this thesis do not merely suggest that a GCC green hydrogen corridor is possible. They demonstrate that it is, of all the configurations analysed, the most scientifically defensible design for a regional green hydrogen future.

6.5 Future Work

This thesis has established a multi-objective, multi-method optimisation framework for green hydrogen supply chain design in the GCC, generating quantitative insights across two case study contexts. However, several directions for future research are identified to extend and refine the findings presented here.

First, the temporal resolution of the supply chain model should be extended to incorporate sub-annual or seasonal variability in solar PV generation. The current framework treats energy supply as a fixed annual average, which does not capture the impact of diurnal and seasonal intermittency on electrolyser utilisation, storage cycling, and supply reliability. Integrating higher-resolution solar profiles, including dust storm frequency, soiling loss rates, and seasonal irradiance distributions, would enable more precise sizing of storage capacity and more realistic electrolyser dispatch modelling. This is particularly relevant to the GCC context, where extreme climate conditions can create significant deviations from annual averages.

Second, the scope of the case studies should be expanded to include all six GCC member states within a single integrated optimisation model. The current research addresses Kuwait and Saudi Arabia as independent case studies, with comparative analysis conducted post-hoc. A unified trans-national optimisation model would allow for the explicit co-optimisation of production siting, pipeline routing, and geological storage selection across the full GCC network, enabling more precise quantification of the economies of scale and spatial arbitrage benefits associated with the proposed GCC Hydrogen Corridor Architecture.

Third, future work should incorporate a more granular treatment of water availability and desalination costs as an explicit constraint in the optimisation model. Green hydrogen production via electrolysis requires purified water, and in the water-scarce GCC context, the cost and energy intensity of seawater desalination represent a non-trivial input that can affect both the LCOH and the carbon footprint of the supply chain. Including water as a fourth objective function or as a binding resource constraint would substantially improve the realism of the model.

The stakeholder survey component of the AHP weighting process could be expanded to include a larger and more diverse respondent panel, including demand-side stakeholders such as hydrogen importers in Europe and East Asia. This would allow for an analysis of how divergent perspectives between supply-side (GCC) and demand-side (importing regions) stakeholders influence the optimal supply chain configuration, and may reveal important tensions in infrastructure planning that are not captured by a supply-side-only survey.

Finally, emerging electrolyser technologies- particularly solid oxide electrolysis (SOEC) and advanced AEM systems- should be incorporated into future iterations of the model as they approach commercial readiness. The technology landscape for green hydrogen is evolving rapidly, and periodic updates to the model's technology database will be necessary to maintain the relevance of the optimisation outputs through the 2030s and 2040s. A lifecycle assessment (LCA) integrated within the MILP framework would also allow for a more comprehensive environmental evaluation that goes beyond carbon footprint to include land use, water consumption, material extraction, and end-of-life impacts across the full supply chain.

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Appendix B: Kuwait AHP Analysis

B.1 Kuwait Production AHP

The AHP analysis for Kuwait was conducted as a single-period evaluation for 2050. Pairwise comparison matrices were developed for production, storage, and transportation stages based on a survey of 10 hydrogen experts, following the nine-point intensity scale of Saaty [94]. Consistency ratios (CR) were confirmed to be below the 0.10 threshold in all cases prior to integration into the MILP framework.

Nine-point intensity scale: 1 = Equal importance; 3 = Moderate importance; 5 = Strong importance; 7 = Very strong importance; 9 = Absolute importance.

Pairwise comparison matrix: Table B.1 (main thesis). Derived weightings:

Appendix Table B.1: Kuwait AHP production criteria weightings

Criterion	AHP Weighting
CAPEX	0.303
OPEX and Maintenance Costs	0.185
Efficiency	0.103
Carbon Footprint	0.098
Risk Index	0.085
Land Use	0.073
Electricity Use	0.062
Lifetime	0.043
Purity of H_2 Produced	0.028
Water Consumption	0.020

AHP weightings rounded to three decimal places. CR < 0.10.

B.2 Kuwait Storage AHP

Appendix Table B.2: Kuwait AHP storage criteria weightings

Criterion	AHP Weighting
CAPEX	0.288

Criterion	AHP Weighting
OPEX and Maintenance Costs	0.166
Efficiency	0.111
Storage Capacity	0.125
Storage Volume	0.089
Lifetime	0.079
Risk Index	0.050
Charging Rate	0.044
Energy Density	0.031
Carbon Footprint	0.019

AHP weightings rounded to three decimal places. CR < 0.10.

B.3 Kuwait Transportation AHP

Appendix Table B.3: Kuwait AHP transportation criteria weightings

Criterion	AHP Weighting
CAPEX	0.266
OPEX and Maintenance Costs	0.153
Efficiency	0.110
Transport Capacity	0.127
Transport Volume	0.090
Lifetime	0.081
Risk Index	0.051
Charging Rate	0.045

Criterion	AHP Weighting
Energy Density	0.033
Distance Before Refuelling	0.027
Carbon Footprint	0.017

AHP weightings rounded to three decimal places. CR < 0.10.

Appendix C: Saudi Arabia AHP Analysis - Dynamic Multi-Period Weightings

The Saudi Arabia AHP analysis was conducted for each of the four planning periods (2025, 2035, 2045, 2060), with pairwise comparison matrices re-evaluated for each period to reflect the anticipated evolution of stakeholder priorities over time. All weightings were derived from expert surveys of 10 hydrogen specialists. Consistency ratios (CR) were confirmed below 0.10 for all matrices.

C.1 Saudi Arabia Production AHP Weightings

Period 1 (2025)

Appendix Table C.1: Saudi Arabia production AHP weightings - Period 1 (2025)

Criterion	AHP Weighting
CAPEX	0.309
OPEX and Maintenance Costs	0.060
Efficiency	0.059
Carbon Footprint	0.032
Risk Index	0.168
Land Use	0.063
Electricity Use	0.054
Lifetime	0.027
Purity of H_2 Produced	0.019
Production Capacity	0.100
Water Consumption	0.110

AHP weightings rounded to three decimal places. CR < 0.10.

Period 2 (2035)

Appendix Table C.2: Saudi Arabia production AHP weightings - Period 2 (2035)

Criterion	AHP Weighting
CAPEX	0.044
OPEX and Maintenance Costs	0.060
Efficiency	0.154
Carbon Footprint	0.151
Risk Index	0.115
Land Use	0.029
Electricity Use	0.035
Lifetime	0.103
Purity of H_2 Produced	0.110
Production Capacity	0.120
Water Consumption	0.080

AHP weightings rounded to three decimal places. CR < 0.10.

Period 3 (2045)

Appendix Table C.3: Saudi Arabia production AHP weightings - Period 3 (2045)

Criterion	AHP Weighting
CAPEX	0.038
OPEX and Maintenance Costs	0.064
Efficiency	0.117
Carbon Footprint	0.135
Risk Index	0.136

Criterion	AHP Weighting
Land Use	0.032
Electricity Use	0.093
Lifetime	0.081
Purity of H_2 Produced	0.063
Production Capacity	0.117
Water Consumption	0.122

AHP weightings rounded to three decimal places. CR < 0.10.

Period 4 (2060)

Appendix Table C.4: Saudi Arabia production AHP weightings - Period 4 (2060)

Criterion	AHP Weighting
CAPEX	0.030
OPEX and Maintenance Costs	0.030
Efficiency	0.132
Carbon Footprint	0.125
Risk Index	0.090
Land Use	0.094
Electricity Use	0.094
Lifetime	0.085
Purity of H_2 Produced	0.088
Production Capacity	0.103
Water Consumption	0.130

AHP weightings rounded to three decimal places. CR < 0.10.

C.2 Saudi Arabia Storage AHP Weightings

Period 1 (2025)

Appendix Table C.5: Saudi Arabia storage AHP weightings - Period 1 (2025)

Criterion	AHP Weighting
CAPEX	0.305
OPEX and Maintenance Costs	0.108
Efficiency	0.149
Storage Capacity	0.046
Storage Volume	0.042
Lifetime	0.088
Risk Index	0.154
Charging Rate	0.037
Energy Density	0.050
Carbon Footprint	0.021

AHP weightings rounded to three decimal places. CR < 0.10.

Period 2 (2035)

Appendix Table C.6: Saudi Arabia storage AHP weightings - Period 2 (2035)

Criterion	AHP Weighting
CAPEX	0.048
OPEX and Maintenance Costs	0.042
Efficiency	0.136
Storage Capacity	0.082
Storage Volume	0.074
Lifetime	0.110

Criterion	AHP Weighting
Risk Index	0.175
Charging Rate	0.078
Energy Density	0.148
Carbon Footprint	0.107

AHP weightings rounded to three decimal places. CR < 0.10.

Period 3 (2045)

Appendix Table C.7: Saudi Arabia storage AHP weightings - Period 3 (2045)

Criterion	AHP Weighting
CAPEX	0.042
OPEX and Maintenance Costs	0.042
Efficiency	0.140
Storage Capacity	0.124
Storage Volume	0.090
Lifetime	0.105
Risk Index	0.143
Charging Rate	0.091
Energy Density	0.104
Carbon Footprint	0.118

AHP weightings rounded to three decimal places. CR < 0.10.

Period 4 (2060)

Appendix Table C.8: Saudi Arabia storage AHP weightings - Period 4 (2060)

Criterion	AHP Weighting
CAPEX	0.036
OPEX and Maintenance Costs	0.036
Efficiency	0.168
Storage Capacity	0.110
Storage Volume	0.081
Lifetime	0.083
Risk Index	0.155
Charging Rate	0.073
Energy Density	0.126
Carbon Footprint	0.132

AHP weightings rounded to three decimal places. CR < 0.10.

C.3 Saudi Arabia Transportation AHP Weightings

Period 1 (2025)

Appendix Table C.9: Saudi Arabia transportation AHP weightings - Period 1 (2025)

Criterion	AHP Weighting
CAPEX	0.283
OPEX and Maintenance Costs	0.101
Efficiency	0.142
Transport Capacity	0.048
Transport Volume	0.044

Criterion	AHP Weighting
Lifetime	0.098
Risk Index	0.161
Charging Rate	0.021
Energy Density	0.039
Distance Before Refuelling	0.034
Carbon Footprint	0.027

AHP weightings rounded to three decimal places. CR < 0.10.

Period 2 (2035)

Appendix Table C.10: Saudi Arabia transportation AHP weightings - Period 2 (2035)

Criterion	AHP Weighting
CAPEX	0.028
OPEX and Maintenance Costs	0.045
Efficiency	0.157
Transport Capacity	0.090
Transport Volume	0.082
Lifetime	0.069
Risk Index	0.162
Charging Rate	0.083
Energy Density	0.102
Distance Before Refuelling	0.087
Carbon Footprint	0.094

AHP weightings rounded to three decimal places. CR < 0.10.

Period 3 (2045)

Appendix Table C.11: Saudi Arabia transportation AHP weightings - Period 3 (2045)

Criterion	AHP Weighting
CAPEX	0.037
OPEX and Maintenance Costs	0.037
Efficiency	0.124
Transport Capacity	0.113
Transport Volume	0.084
Lifetime	0.085
Risk Index	0.129
Charging Rate	0.084
Energy Density	0.094
Distance Before Refuelling	0.106
Carbon Footprint	0.106

AHP weightings rounded to three decimal places. CR < 0.10.

Period 4 (2060)

Appendix Table C.12: Saudi Arabia transportation AHP weightings - Period 4 (2060)

Criterion	AHP Weighting
CAPEX	0.031
OPEX and Maintenance Costs	0.031
Efficiency	0.143
Transport Capacity	0.107
Transport Volume	0.081
Lifetime	0.075
Risk Index	0.141
Charging Rate	0.071
Energy Density	0.115
Distance Before Refuelling	0.100
Carbon Footprint	0.108

AHP weightings rounded to three decimal places. CR < 0.10.

Appendix D: GAMS Optimisation Code

The following GAMS code illustrates the MILP optimisation model as applied to hydrogen production in Saudi Arabia for Planning Period T1 (2025) under the high-demand scenario. This example demonstrates the general modelling structure applied consistently across all supply chain stages and planning periods for both case studies. Alternatives: A1 = PEM Electrolysis; A2 = AEM Electrolysis; A3 = Alkaline Water Electrolysis. Criteria C1–C11 correspond to CAPEX, OPEX, Efficiency, Carbon Footprint, Land Use, Water Consumption, Electricity Use, Lifetime, Purity, Production Capacity, and Risk Index respectively. Positive weights indicate benefit criteria (maximised); negative weights indicate cost criteria (minimised).

The model was solved using GAMS 45.1.0 (General Algebraic Modelling System) with the CPLEX solver. The weighted-sum formulation converts the multi-criteria problem to a single-objective MIP, solved to global optimality.

```
$title GCC Green Hydrogen Supply Chain Optimisation - Saudi Arabia T1 2025 (Production) Set    i 'criteria' /C1, C2, C3, C4, C5, C6, C7, C8, C9,
C10, C11/    j 'alternatives' /A1, A2, A3/;  Table d(i,j) 'data collection for hydrogen production'            A1          A2          A3    C1          672342164
546790825     609919450     C2          33617108.2  27339541.25  30495972.5     C3          70          67          65     C4          13          578          4.3     C5
10          10          13     C6          18          20          20     C7          58          60          55     C8          50000          20000          60000     C9          99.999          99.93
99.92     C10          1          1          3     C11          3          3          5;  Parameter c(i,j) 'normalized matrix'; Parameter row_sum(i); Parameter w(i) 'weight:
positive=benefit  criterion,  negative=cost  criterion';  row_sum(i)=sum(j,d(i,j));  c(i,j)=d(i,j)/row_sum(i);  w('C1')=-0.3089;       w('C2')=-0.0598;
w('C3')=0.0591;  w('C4')=-0.032;      w('C5')=-0.0627;     w('C6')=-0.11;  w('C7')=-0.0538;     w('C8')=0.0269;      w('C9')=0.0185;  w('C10')=0.1003;
w('C11')=-0.1681;  Positive Variable x(j); Variable z 'objective'; Equation score 'final score'; score.. z =e= sum((i,j),c(i,j)*x(j)*w(i)); Equation Limit
'Limit of variables summation'; Limit.. sum(j,x(j))=e=1; Model milp_model /all/; Solve milp_model using mip maximizing z; Display x.l, z.l;
```

Source code applies to the high-demand scenario. For medium- and low-demand cases, input data (C1 CAPEX values) are adjusted proportionally according to the demand scaling methodology described in Chapter 3.2, while the model structure and weights remain unchanged.