Report

A techno-economic and financial analysis of a Gulf-India undersea electricity interconnector

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Abstract: As part of efforts to decarbonise, power systems around the world will need to cope with increasing shares of intermittent renewable generation from technologies such as wind and solar photovoltaics (PV) in the coming decades. One promising solution to this challenge is cross-border electricity interconnectors. This study is an independent combined techno-economic and financial analysis of an electricity interconnector between Gulf Cooperation Council (GCC) countries and India. A techno-economic model of a combined India-GCC power system was developed using OSeMOSYS, an open-source energy system modelling tool and combined with a financial model. The models were applied across 75 scenarios covering a range of cost variables and solar PV locations in the GCC. We find that a techno-economic case for a GCC-India interconnector is clear: an interconnector is part of the least-cost 'optimal' power system in 64 of the 75 scenarios studied. The trend of electricity flows gradually shifts from the India->GCC direction in 2030 to the other way around by 2050. The overall trade volumes are influenced by the location of the solar PV farm; locations further to the west contribute towards higher trade volumes in the GCC->India direction. Of the cost variables considered in the study the overall (social) discount rate is most strongly correlated with the interconnector trade volumes. The financial case for the CCG-India interconnector is less clear. Of the projections developed for the scenarios from the technoeconomic model, only a small number are immediately investible. It is also expected that a smaller interconnector will be a more attractive investment opportunity, for a trade-off in total system cost reductions.

Keywords: energy systems modelling; techno-economic analysis; financial modelling; electricity interconnectors; India; Gulf Cooperation Council;

Introduction

Many large economies have now announced net zero target years. These include the UK (The Government of the United Kingdom, 2020), EU, and China (Varro and Fengquan, 2020). With President Biden now in office, the US is also expected to announce a net zero target imminently[1]. The IEA recently suggested that a net zero target for the global energy system is now within reach (Fatih Birol, 2021). While India has not yet announced a net zero target of its own, it is emerging as a global leader in renewables deployment - ranked 3rd and 4th globally in solar photovoltaic (PV) and wind power capacity additions in 2019 (REN21, 2020). The power sector will therefore have to cope both with increasingly electrified energy systems as well as higher shares of intermittent renewable generation capacity such as wind and solar photovoltaics (PV) in the coming decades. One promising solution to this challenge is cross-border electricity interconnectors. By connecting geographically distributed renewable potentials to electricity demands across borders, supply-demand mismatches (Brinkerink et al., 2019). Championing this concept, India's Prime Minister has announced the ambitious 'One Sun, One World, One Grid' initiative that envisions a globally interconnected electricity grid to complement the plans of the International Solar Alliance (ISA)[2] for round-the-clock solar power generation. The objective in the first of three phases in this initiative is to assess the technically and financially viability of an interconnector between the six Gulf Cooperation Council states, India, and South-East Asia.

This study is an independent combined techno-economic and financial analysis of an electricity interconnector between GCC and India. It aims to answer four key questions in this regard:

- Is an electricity interconnector between GCC and India considering techno-economically and financially favourable across a range of scenarios?
- If built, what are the daily and seasonal patterns of trade flows across the interconnector?
- What are the key factors that influence the choice to build and profile of electricity flows across the interconnector?
- How can a GCC-India interconnector contribute towards India's transition to a low or zero emissions power system?

Modelling approach

Several recent studies of India's long-term energy outlook - such as those by NREL (Rose et al., 2020) and TERI (Spencer et al., 2020) - are underpinned by techno-economic models. Similarly, the modelling tool used to carry out the techno-economic analysis in this study is OSeMOSYS (Howells et al., 2011), a widely used open-source

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[1] Not yet formalised
[2] https://isolaralliance.org/

energy planning tool. OSeMOSYS uses linear optimisation to identify the least cost ‘optimal’ system over a given time horizon under user-specified constraints.

A financial model has been prepared alongside the technoeconomic model, capable of taking the technoeconomic model’s projections of the energy system as inputs, and determining whether the interconnector would be investible beyond being techno-economically desirable. The financial model is implemented as both a spreadsheet and a Python module.

Model setup

The techno-economic model was developed in two phases. In phase 1, the model included a representation both GCC and Indian power systems. It consisted of six countries on the GCC side, with Saudi Arabia divided into four regions and the remaining five countries each represented separately. The Indian power system was divided into five regional grids. Further, an interconnector between Oman on the GCC side and the Western grid of India is also represented.

The model was then updated based on the feedback from phase 1 to include bi-directional trade, the option of multiple solar PV sites in the GCC, and battery storage deployment in India.

The financial model has been designed to extend the findings of the technoeconomic model, drawing on a common group of scenarios, and extending the findings with further financially-relevant parameters and assumptions.

Scenario Parameterisation

The development of the technoeconomic and financial models has been closely linked - the ranges of key parameters for both models was decided between the modelling teams prior to the scenarios being run. In this Phase 2 of the GUI feasibility study, scenario parameterisation has focused closely on the costs of the interconnector, which Phase 1 showed to be determining factors in the interconnector’s desirability. These parameters include capital costs, operating costs, the social discount rate, and the project cost of capital.

We obtain figures for capital expenditure (CAPEX) by other similar HVDC interconnector projects. Based on these projects, we are able to significantly reduce the parameter search space. Table 1 shows key CAPEX parameters for comparator projects. We choose a CAPEX parameter range of $0.45mn/MW to $2.0mn/MW, which captures the range of comparable overland and underwater interconnector projects.

Table 1: Interconnector capital cost comparison

Interconnector	Size [MW]	Distance	Over/under	Cost [US$mn]	Unit Cost [US$mn/MW]	Sources*
ES-FR	2000	70	overland	837	0.42	1
Labrador Island Link	900	1100	overland	2145	2.38	2
CASA-1000	1300	1227	overland	977	0.75	3
GCCIA	1200	1104	overland	1537	1.28	3
PowerLinks	3000	1200	overland	341	0.11	4
Plains & Eastern	4000	1160	overland	2500	0.63	5
IL/Cyprus/GR	2000	1500	underwater	900	0.45	6
Viking Link DK-GB	1400	765	underwater	2390	1.71	7
English Channel FR-GB	2000	40	underwater	412	0.21	8
Maritime Link (CA)	500	180	underwater	962	1.92	9
Trans Bay Cable Project	400	85	underwater	440	1.10	10
Cross Sound Cable	330	39	underwater	120	0.36	11
East-West (IE-GB)	500	260	underwater	720	1.44	3
NorNed	700	580	underwater	720	1.03	3

Hudson Transmission Project	660	12	underwater	850	1.29	12
				MIN	**0.11**	
				MAX	**2.38**	
				MEAN	**1.01**	

*sources: 1: https://web.archive.org/web/20111005233257/http://social.csptoday.com/qa/spain-invest-heavily-transmisson-grid-upgrades-over-next-five-years; 2: https://www.transmissionhub.com/articles/transprojects/labrador-island-link; 3: https://sari-energy.org/wp-content/uploads/2019/07/Session-3-Case-Studies-on-Financing-Models.pdf; 4: https://documents.worldbank.org/en/publication/documents-reports/documentdetail/671171468017990099/estimating-employment-effects-of-powerlinks-transmission-limited-project-in-india-and-bhutan; 5: https://www.eia.gov/analysis/studies/electricity/hvdctransmission/pdf/transmission.pdf ; 6: https://www.reuters.com/article/idUSKBN2B015M; 7: http://viking-link.com/; 8: https://en.wikipedia.org/wiki/High-voltage_direct_current; 9: https://www.linxon.com/project/maritime-link-emera-500-mw-hvdc-connection-project-canada/; 10: https://en.wikipedia.org/wiki/Trans_Bay_Cable; 11: https://en.wikipedia.org/wiki/Cross_Sound_Cable; 12: https://www.eia.gov/analysis/studies/electricity/hvdctransmission/pdf/transmission.pdf

Operational expenditures (OPEX) were assumed to be negligible in Phase 1. In Phase 2 we return to this assumption and obtain OPEX rates for comparable submarine HVDC projects in the North Sea (Flament et al. 2014). Cables have a higher OPEX rate than converter station equipment, so we choose an OPEX range that represents a blend of these rates. This blend sufficiently covers the parameter space so that more detail can be added in downstream analysis.

While the ultimate discount rate used for the project will be a function of the capital structure of the project, a range is chosen to be represented in the technoeconomic modelling of the project. The financial model can then be tuned to different scenario runs for consistency between the two models. With further research we have been able to narrow the range of discount rates as compared to Phase 1.

The World Bank (Meier, P. 2020) has issued guidance on the use of discount rates in the analysis of electricity projects. Taking a welfare approach, they adopt social discount rates in the range of 5% to 10%. This range is used as the social discount rate in the technoeconomic model.

The project discount rate will be determined by the cost of capital of those who fund the project. In the financing of the GCCIA Interconnector, for example, costs were split according to which parties most benefited from the interconnector, and a commensurate cost of capital (7.55%) was used for the project. For this project, costs of capital are expected to also fall in this range. The range of 5% to 10% is likewise used for the project cost of capital.

With the input parameter spaces established, the scenarios can be sampled from their range. The range for each variable is shown in **Table 2**. Using these input data ranges, twenty-five ‘samples’ were created to combine different values for each parameter through a process of Latin Hypercube sampling.

Table 2. Cost input data ranges to create twenty-five 'samples'

Variable	CapitalCost	DiscountRate
Interconnector CAPEX	450 $/kW	2000 $/kW
Interconnector OPEX (% of CAPEX)	1.2%	2.1%
Social discount rate	5%	10%
Project cost of capital	5%	10%

In addition to the twenty-five samples, three potential sites for a solar PV farm in the GCC were also identified. The sites were selected based on their longitude and solar PV generation potential. The selected locations, and their coordinates, are East (17.4599 N, 54.8877 E), Centre (22.2344 N, 42.8657 E), and West (29.0957 N, 35.5765 E). The first site is located in Oman while the remaining two are in Saudi Arabia.

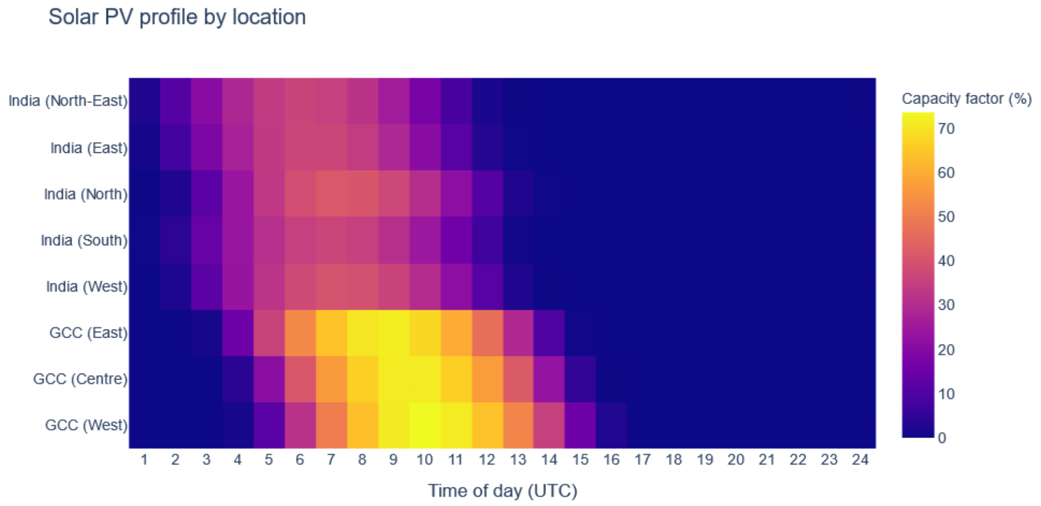


Figure 1. Average daily solar PV profile by location. X-axis: Hours in UTC; Colour bar: Capacity factor in % by hour for each solar PV site. Values for the five locations in India are averages of the existing solar PV installations in each region. For GCC, the profiles are specific to selected sites for a potential solar PV farm feeding the GUI

The time difference between the GCC and India, especially relating to coincident solar power generation in the former and peak demand hours in the latter, is a key factor in considering the GUI. In order to analyse the importance of this time difference, three potential sites for a solar PV farm are selected and included in the techno-economic model. Each site is considered independently of the other – only one site is active in each scenario. The three sites are each analysed across the 25 samples described in the previous section to provide a set of 75 scenario runs.

Counterfactual Analysis

A key criterion in the design of the financing of an interconnector project is understanding which of the interconnected parties has the most to gain from the interconnection. The benefitting party is more likely to finance the interconnector and therefore the capital structure and costs of capital is dependent on who the interconnector beneficiary is.

Determining the interconnector beneficiary is not trivial. Interconnected countries experience a range of benefits including reduced system marginal costs, reduced system capital costs, access to markets, and stability of electricity supply (SARI/EI/IRADE Team 2019). These benefits may be asymmetrically distributed and difficult to quantify. They also depend on the choice of counterfactual scenario. A counterfactual scenario with a hard decarbonisation constraint, for example, will have a different distribution of marginal and capital costs than a business-as-usual baseline.

To develop some initial insight into the distribution of benefits of the proposed interconnector, we compare a counterfactual business-as-usual case that has been constrained to not build the interconnector to an unconstrained central scenario. **Figure 2** shows that the addition of the interconnector has a large impact on the mean marginal cost of electricity in interconnected countries, weighted by hourly electricity demand. The interconnector reduces mean electricity costs in GCC countries. These savings may or may not be forwarded to rate payers depending on the design of the electricity market.

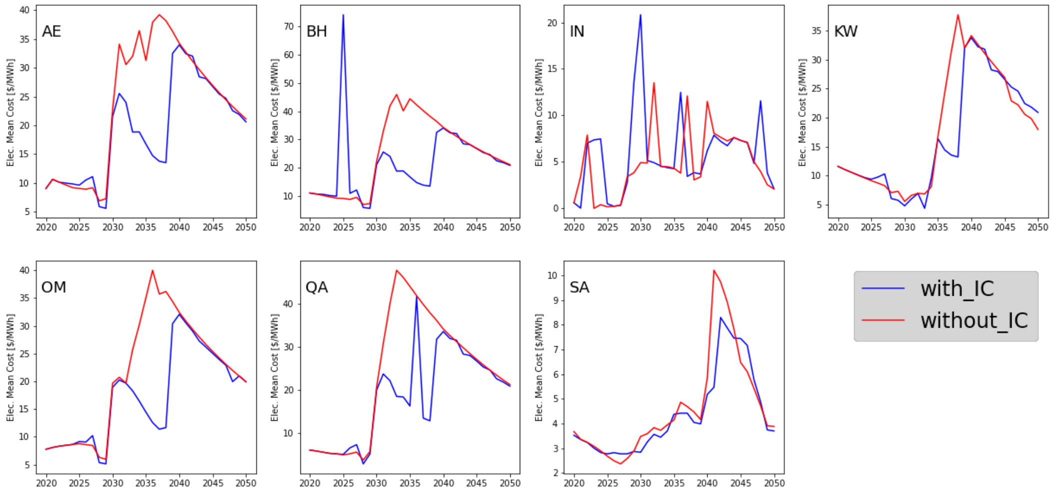
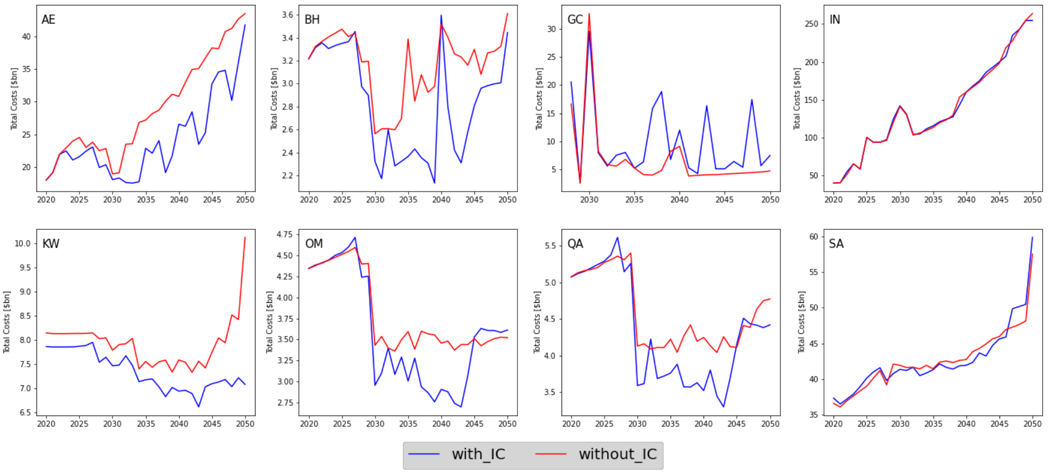


Figure 2: Marginal electricity costs in counterfactual scenario by country

Figure 3 shows that the presence of the interconnector decreases total system costs in GCC countries, while total system costs in India are largely unchanged. This is consistent with the findings of the technoeconomic model that show that most interconnector trade volume occurs in the direction of electricity export from India to the GCC.



AE: United Arab Emirates; **BH:** Bahrain; **GC:** GCC; **IN:** India; **KW:** Kuwait; **OM:** Oman; **QA:** Qatar; **SA:** Saudi Arabia

Figure 3: Total system costs in counterfactual scenario by country

Despite the finding of reduced marginal and system costs in GCC countries, it remains unclear which country or collection of countries will have the most incentive to pay for the interconnector. Interconnectors are often built to give national champion industries access to export markets, such as the Ireland-UK interconnector built by the Ireland grid operator to give zero-marginal-cost Irish wind power access to the UK power market (SARI/EI/IRADE Team 2019). Considering that this project is of national interest to the Government of India under the One Sun, One World, One Grid concept, geopolitical interests may prove the determinant of which party builds the interconnector.

In the financial model, we proceed with the assumption that the interconnector will be championed by the Government of India, built by Indian companies, and financed by development and investment banks operating in India.

Business Model Selection

The business models of the proposed interconnector describe how it will make revenue to cover its costs and service its debt. Four business models have been identified which can provide cost recovery for the proposed interconnector.

1. Generator Supply Dedicated Line - For a unidirectional line from a generating station to a demand node, costs are recovered directly from the sale of electricity. Typical of, e.g., remote hydro power resources.
2. Regulated grid tariff - A regulated tariff for transmission capacity, levied by the regulator. A typical arrangement for, e.g., domestic transmission lines. Tariffs may be levied on generators or consumers.
3. Transmission rights model - Retailers buy forward transmission rights which have fixed prices. Typical for well-coupled markets, e.g., France-UK.
4. Congestion charge model - Interconnector levies a variable ‘congestion’ charge. Most common between markets where variable arbitrage opportunities occur, e.g., between wind-rich Ireland and the UK.

Because two-way trading is desired for the CCG-GUI project, consistent with the One-sun-one-world-one-grid concept, a generator-supply business model is not appropriate for the financial model. The least-costs decision-making of the technoeconomic model takes full advantage of time-of-use marginal costs, so the financial model must also reflect the significant and variable arbitrage opportunities expected to exist between the GCC and Indian power markets. As such the design of the financial model proceeds assuming a variable time-of-use tariff consistent with a congestion charge model. This tariff will be determined by the technoeconomic model and will be based upon the difference between the marginal costs of electricity in India and the GCC.

Interconnector Capital Structure

Models for financing large electricity infrastructure projects include private finance, utility finance, and public-private partnership. These financing arrangements feature different typical capital structures for the legal entity that owns the interconnector. The capital structure of the entity will be used to determine the weighted average cost of capital (WACC) which will be used to interpolate the technoeconomic results. The capital structure also plays a crucial role in the cashflow of the interconnector project, determining interest payments and financing fees.

For a project of this size, a public-private partnership is typical, where governments, regulated companies, private lenders, and multilateral financial institutions jointly finance the infrastructure. This implies a capital structure that combines private and public (government) equity, commercial debt, concessionary loans, and public grants. Concessionary loans would typically be provided by a multilateral development bank.

We prepare a baseline capital structure which can be adjusted according to different assumptions. This capital structure is comparable to other large interconnector projects, such as the PowerLinks interconnector that carries electricity from Bhutan to New Delhi, India (PowerLinks Tranmission Ltd 2009). summarises the GUI baseline capital structure and compares it to the PowerLinks capital structure.

Table 3: GUI baseline capital structure and comparison project

	GUI Baseline		**PowerLinks Transmission Ltd**	
Grant	[Unspecified]	2.5%	[None]	0%
Equity	[Unspecified]	22.5%	Tata Power Company Ltd	12.9%
			Powergrid Corporation of India Ltd	12.4%
	Sum	**25%**	**Sum**	**24.3%**
Debt	Development Bank 1	16.5%	International Finance Corporation (World Bank)	22.5%
	Development Bank 2	19.5%	Asia Development Bank	19.9%
	Commercial Bank	22.5%	Infrastructure Development Finance Limited	17.1%
	Government Debt	16.5%	State Bank of India	15.2%
	Sum	**75%**	**Sum**	**74.7%**
Sum		**100%**		**100%**

Cost of Capital

With a capital structure in place, we can begin to develop assumptions for the GUI's cost of capital. We obtain literature values to provide preliminary assumptions for the cost of equity and the cost of debt of the project.

The World Bank occasionally publishes a schedule of lending rates and fees that can be used to estimate the debt margin and fees levied for World Bank lending (The World Bank 2021). For India, World Bank variable spread lending is available at 0.82% for a 15-year tenor. Keeping with the analogous comparison to the PowerLinks interconnector, we also obtain a similar debt margin for the Asia Development Bank (2021).

For commercial and government debt, the rates are more difficult to obtain. We use a rate of 7% for government lending, slightly more than the risk-free rate for India (countryeconomy.com 2021). For commercial lending, our baseline rate is 20%.

We develop a cost of equity using the capital asset pricing model. In this case we include only the risk-free rate and the equity market risk premium. We assume the risk-free rate to be equal to the yield of a Government of India sovereign bond: 6.15% (ibid.). We use an equity risk premium of 7%, following the recent guidance of RBSA Advisors (2020).

Variable spread lending applies debt margins on top of a baseline interest rate, typically the London Interbank Overnight Rate (LIBOR). We use a baseline LIBOR of 0.2% (bankrate.com 2021).

Cashflow Analysis

With a cost of capital and capital structure decided, the full cashflow of the proposed GUI can be projected. A key difference between the logic of the technoeconomic model and the financial model is that in the technoeconomic model, construction costs are assumed to be overnight in a given year. In the financial model, we recognise that for a construction project of this size, project costs begin several years before the nominal commissioning year. The financial model spreads construction costs over the five years preceding each capacity addition using a fixed spending profile.

Construction costs are met first by grant and equity drawdowns. Once equity and grant allocations are depleted, debt is drawn down to pay construction costs. Each capacity addition is considered a new project phase, so equity can be drawn down for distant future phases, while debt is being drawn down for near future phases where equity funding has been depleted, all while debt for previous construction phases is being serviced.

Debt drawdowns occurring prior to debt servicing will incur interest payments during the construction period. A commitment fee is also levied on debt which has been committed but not drawn down prior to the commencement of payments (The World Bank 2021). An upfront fee is charged based on total debt requirement when construction begins (Ibid.). These fees and interest payments all increase the total costs and the size of the loans required.

Operating expenses are determined as a portion of the total installed capital asset value. The capital asset value is equal to the unit construction costs multiplied by the installed capacity. In this way, operating expenses scale with the amount of installed capacity and do not extend beyond the equipment's economic lifespan. Following the North Sea Grid annexes, operating expenses are estimated to be in the range of 1.2% to 2% of capital asset value (Flament et al. 2015).

Operating revenue is determined by the technoeconomic model. We assume that the interconnector's variable tariff captures the full price arbitrage between the GCC interconnection node and the Western India grid node. Trade volumes are determined by the technoeconomic model. Revenue is taxed with a fixed corporate tax rate which we set at 15% as a baseline. For a project this large, the corporate rate would be subject to negotiation directly with the government.

Debt is serviced with fixed annual payments. We adopt a baseline loan tenor of 15 years, fitting the 25-year economic lifespan of the infrastructure. The financial model time horizon therefore extends to 2075, 25 years beyond the end of the technoeconomic model, wherein 2049 is the last available year for an overnight capacity addition. Each overnight capacity addition is retired after its 25-year economic life with no terminal value.

A dividend is paid to the interconnector's shareholders from the cashflow available to equity. The net present value of the project is calculated using the remaining net cashflow discounted at the calculated weighted average cost of capital (WACC). Other key financial metrics for the project include the equity internal rate of return (Equity IRR) and project internal rate of return (Project IRR). The Project IRR is the IRR for the 'unlevered' project. The Equity IRR represents the IRR for the full 'levered' project. The Project IRR is used to evaluate returns to the project; the Equity IRR is used to evaluate returns to the project investor. We use the 'modified' IRR (MIRR) method, which is always calculable and makes more sound assumptions concerning reinvestment opportunities. The MIRR is also more suitable for multiphase projects with complex cashflows.

Risk Analysis

The sources of uncertainty and risk to a project of this nature can be classified under financial, commercial, and economic risk. Financial risks include interest rate risk, currency risk, and commodity risks. Commercial risks include offtake risk, non-performance risk, construction risk, environmental risk, and security risks. Economic risks include those related to the macroeconomy and drivers of demand.

These risks can be mapped to parameters in the financial model. While this mapping is imperfect, it allows model results to be stress-tested for robustness. **Table 4** summarises project risks and their analogous parameters in the financial model which can impaired and stress-tested.

Table 4: Project risks and sensitivity testing in the financial model

Risk	Description	Financial Model Parameter
Financial Risks		
Interest Rate	Risk that variable rate loans will suffer rate increases	Stress test by increasing LIBOR
Current	Risk that currency valuation/devaluations will increase the project costs or decrease revenues in real terms	Potentially transferred as currency hedging. Stress test by increasing opex for option cover.
Commodity	Risk that covarying or substitute commodity prices will change averse to project economics	Included in technoeconomic scenario ensemble
Commercial Risks		
Offtake	Unanticipated reduced demand for interconnection services due to offtake failure	Stress test by reducing revenue
Non-performance	The interconnector may suffer unanticipated downtimes or failures	Stress test by reducing revenue
Construction	Construction can suffer delays or cost overruns	Stress test by increasing construction costs beyond 100%
Environmental	Operating and financial impairment due to acute and chronic environmental risks	Potentially transferred as additional insurance, imposing additional opex
Security	Operating and financial impairment due to acute and chronic security risks	Potentially transferred as additional insurance imposing additional opex
Economic Risks		
Macroeconomic	Unanticipated reduced demand for interconnection services due to macroeconomic downturn	Stress test by reducing revenue

Results

The results of the techno-economic modelling are divided into three parts. First, we analyse whether or not the GUI is considered a techno-economically favourable across the 75 scenarios studied. As part of this, we also identify the seasonal and daily patterns of trade flows through the GUI. We then assess the impact of cost variables (**Table 2**) and solar PV farm location on the GCC side on the volume of bi-directional trade through the GUI in the cases where it is built. Finally, we explore the potential contribution of the GUI to India’s transition to a low or zero carbon power system. In this third part, we contrast the role of the GUI against battery storage located in India.

Impact of solar PV location and cost variables

The model results from 75 scenarios show a strong techno-economic favourability of the GUI. The GUI is a part of the least-cost, ‘optimal’ system in all 75 scenarios as shown in **Figure 4**. Of these 75 scenarios, the GUI is built to its maximum capacity of 25 GW in 61 scenarios. The number of cases where the GUI is not built varies depending on the site of the solar PV farm, with the ‘West’ site considered most favourable.

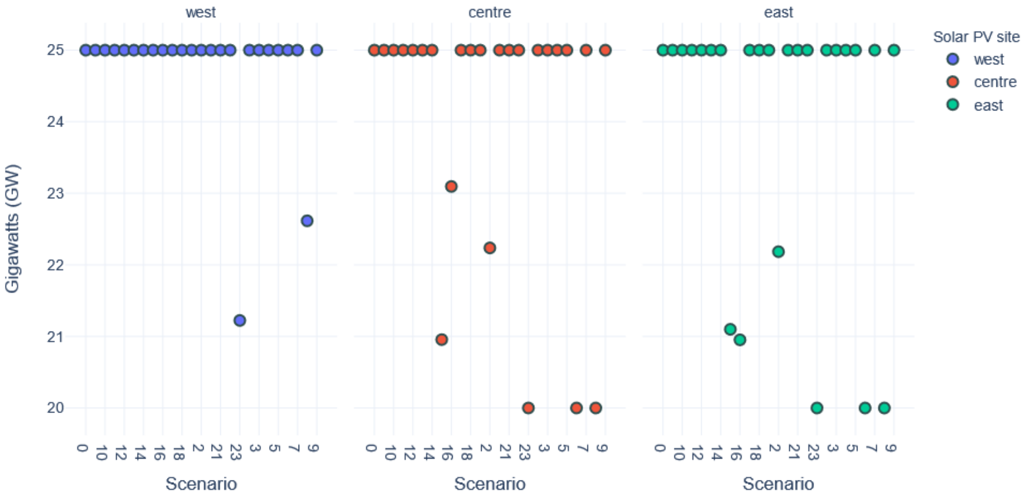


Figure 4. GUI capacity by scenario

When built, the GUI can trade bi-directionally. **Figure 5** below compares the trade volumes in both directions across the GUI until 2050 over the 75 scenarios.

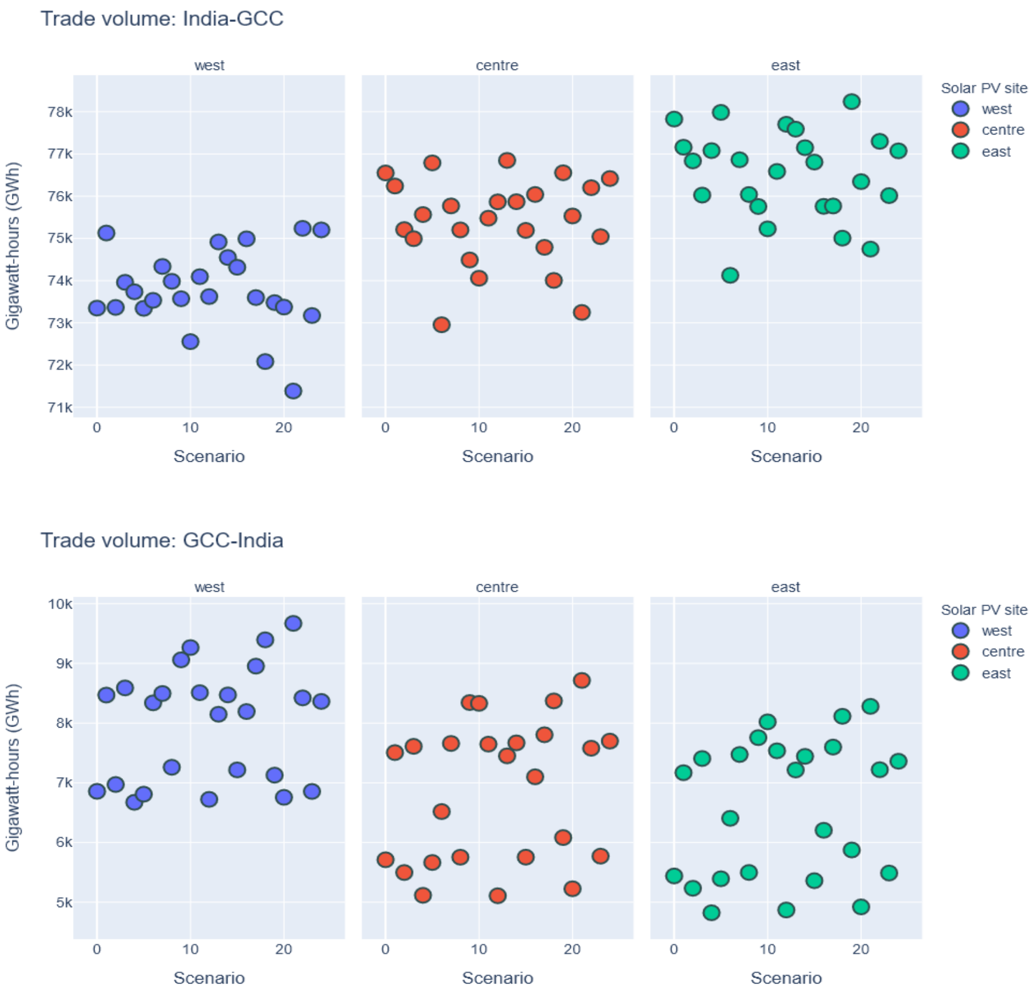
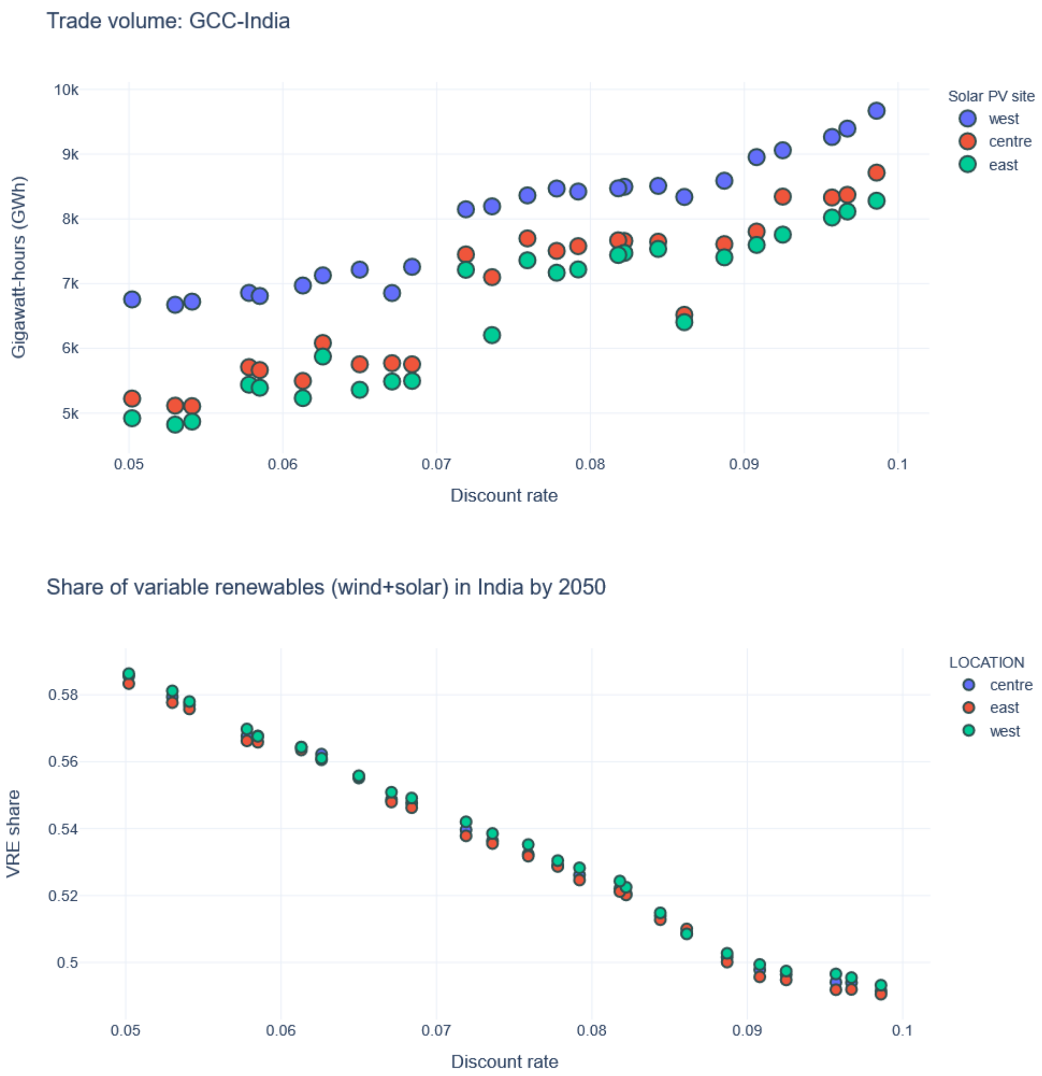


Figure 5. **Total bi-directional electricity trade volumes through the GUI between 2028 and 2050**

The total trade flows in the India->GCC direction, in the 70,000-80,000 GWh range, are significantly higher for all cases as compared to that in the opposite direction, which are below 10,000 GWh for all cases. It appears that GUI flows in the India->GCC direction stem primarily from hydro-based generation in India, allowing the GCC to take advantage of low cost, low carbon electricity from the GUI. This is especially beneficial given that the UAE and Saudi Arabia - the two largest power systems in the GCC - both have emissions reduction targets implemented based on their respective NDCs (Kingdom of Saudi Arabia, 2015; United Arab Emirates, 2020).

In the India->GCC direction, trade flows generally increase as the potential solar PV farm location moves further east. Conversely, in the GCC->India direction, the total trade flows generally decrease from West to East. This trend signifies the importance of the location of solar PV farm site. The further West the site is located, the closer its generation will coincide with India's evening peak demand hours. However, there is a diversity of trade flows across the scenarios in each direction. The main contributing factor that correlates with the trend in trade volumes in the GCC-India direction is the discount rate of each case. At the same time, the discount rate is strongly correlated to the share of variable renewable energy (VRE) capacity in India. A higher discount rate leads to a lower share of VRE Both these trends are shown in **Figure 6**.


Trade volume: GCC-India

Share of variable renewables (wind+solar) in India by 2050

Figure 6. Impact of social discount rate on trade volume

The trend of higher discount rates leading to lower shares of VRE capacity - which have relatively high upfront costs but low running costs - is expected and has been reported in the literature (García-Gusano et al., 2016). In cases with lower shares of VRE capacity, the GUI provides a relatively low-cost alternative for electricity generation, leading to higher trade volumes.

Cross-border electricity trade flows through the GUI

The results of hourly bi-directional trade flows for the years 2030, 2040, and 2050 are shown in **Figure 7**. The direction of trade flows is dominated by electricity from India to GCC in 2030. This pattern remains consistent across all months and for most hours. The exceptions are between 14:00 – 16:00 UTC (19:30-21:30 IST) in all months outside India's monsoon season. The time period coincides with the evening peak demand hours in India. During India's monsoon season, the trade flow is entirely in the direction towards the GCC. This coincides with the likely availability of surplus hydropower generation in India.

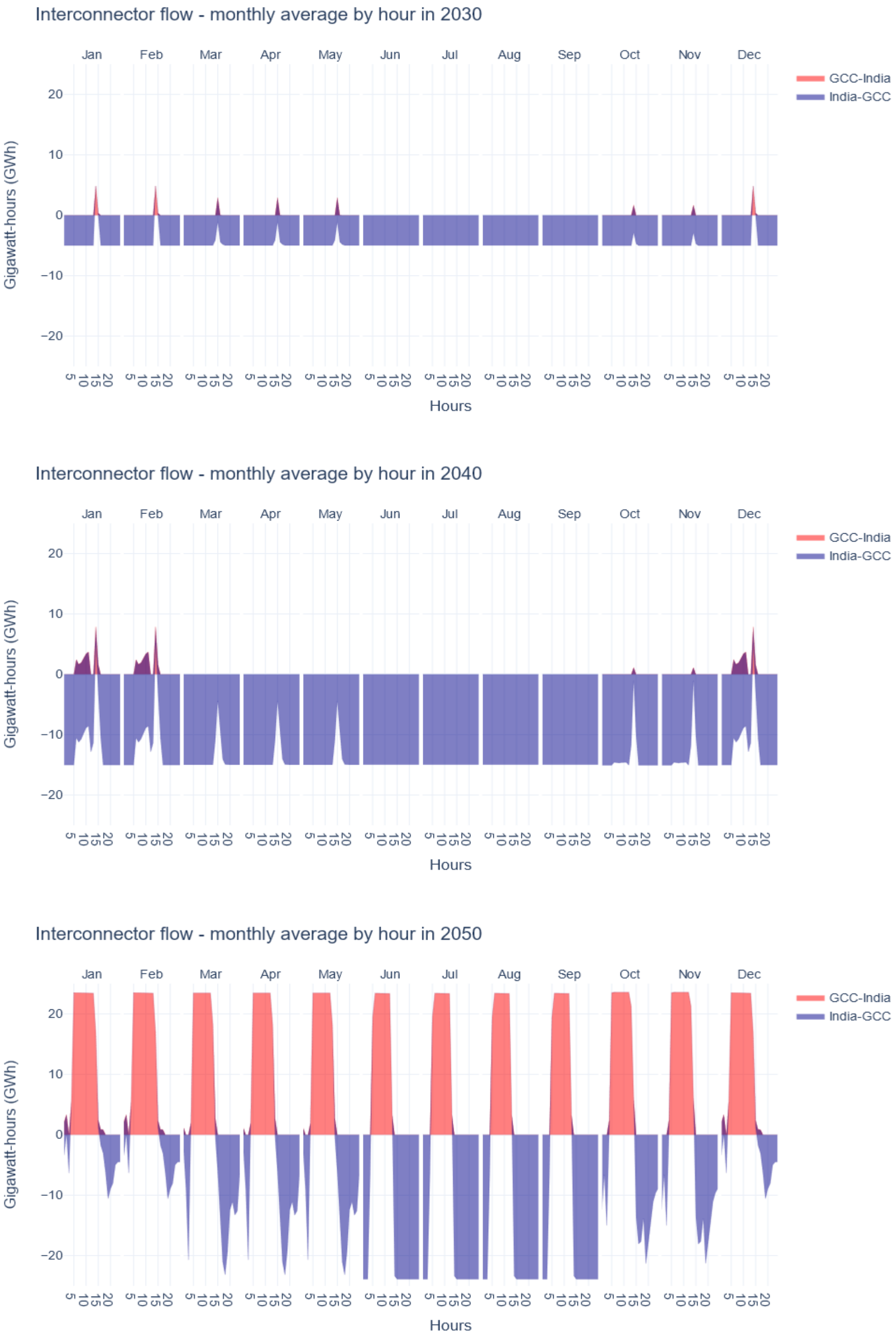


Figure 7. Hourly bi-directional trade volumes across the GUI in 2030, 2040, and 2050

Electricity flows through the GUI in 2040 see a continuation of the earlier pattern of India->GCC dominating the direction of trade. However, in addition to evening peak demand hours in India, there is increased flow of electricity from GCC->India during the daytime peak demand hours of 7:00 – 11:00 UTC (12:30 – 16:30 IST). Maximum hourly electricity flow in the GCC->India direction increases to just under 10 GWh while in the India-GCC direction it increases to 15 GWh.

By 2050 we see a reversal in the dominant direction of flow; electricity trade in the GCC->India direction now makes up a majority of total electricity trade volume. As India reaches its technical potential for renewable capacity expansion, electricity imports from the GUI represent a relatively low-cost alternative. While the seasonal pattern of trade flow from India->GCC remains, the flow in the opposite direction is consistently high throughout the year. The flow now bridges the daytime and evening peak hours, coinciding with both as well as the hours in between. Overall, the GUI is utilised extensively throughout its operational life across the 75 scenarios. The direction of utilisation varies between hours, months, and years.

Impact on power capacity expansion in India

The ensemble of 75 scenarios results in a range of capacity expansion pathways for India's power system (**Figure 8**). The total power generation capacity ranges between 1300 and 1600 GW. The mix of power generation technologies that comprise the system is consistent across the scenarios, with the capacities of hydro and nuclear power in the total capacity mix remaining constant. However, the scenarios are characterised by a wide range of wind and solar capacities from a combined total of 650 to 930 GW.

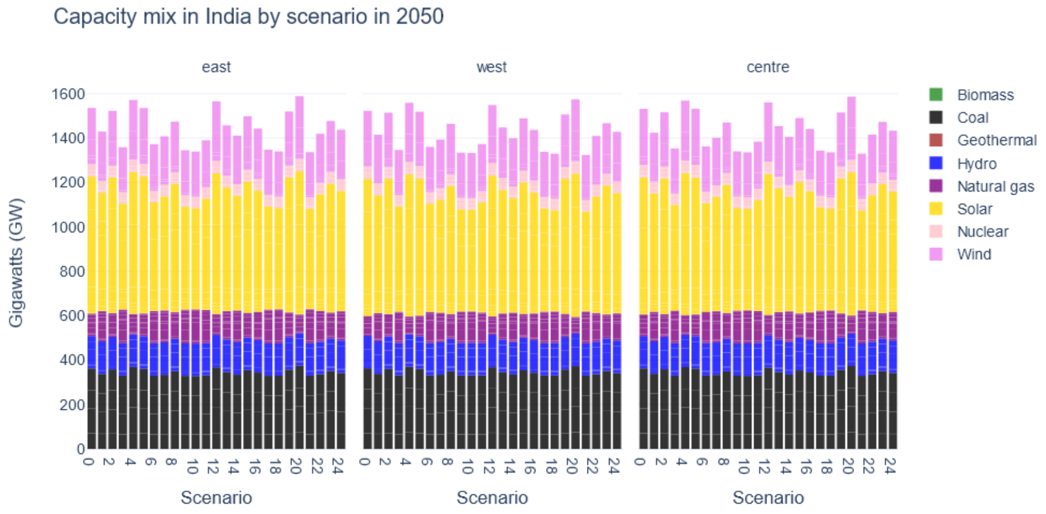


Figure 8. Power generation capacity mix in India by 2050, across twenty-five scenarios and three solar PV sites

Another technology that can help integrate VRE into the power system is electricity storage. Based on the characteristics of the technology they may be best suited for electricity storage of different durations; short (e.g., flywheels), medium (e.g., Li-ion batteries, or long (e.g., pumped hydro). Following the findings from a study by TERI (Spencer et al., 2020), we include a battery storage[3] technology of 60 GW (120 GWh) in the model. The battery technology is assumed to work in tandem with solar PV technologies. We assessed whether the battery technology was a part of the 'least cost' optimal solution and, if so, whether or not it substituted the need for the GUI. The storage duration of the battery is assumed to be 4 hours. The hourly generation results in India for 2050 from the model run are shown in **Figure 9**.

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[3] Our focus in this study was to consider an alternative to the GUI that could help maximise the share of demand in India met by solar PV generation. We therefore consider battery storage located at the sites of solar PV generation in India. While hydro generation from neighbours Nepal and Bhutan, as well as pumped hydro storage within India are key to India's overall power system. However, they would not necessarily be tied to solar PV generation and therefore not considered a clear alternative to the GUI in this regard.

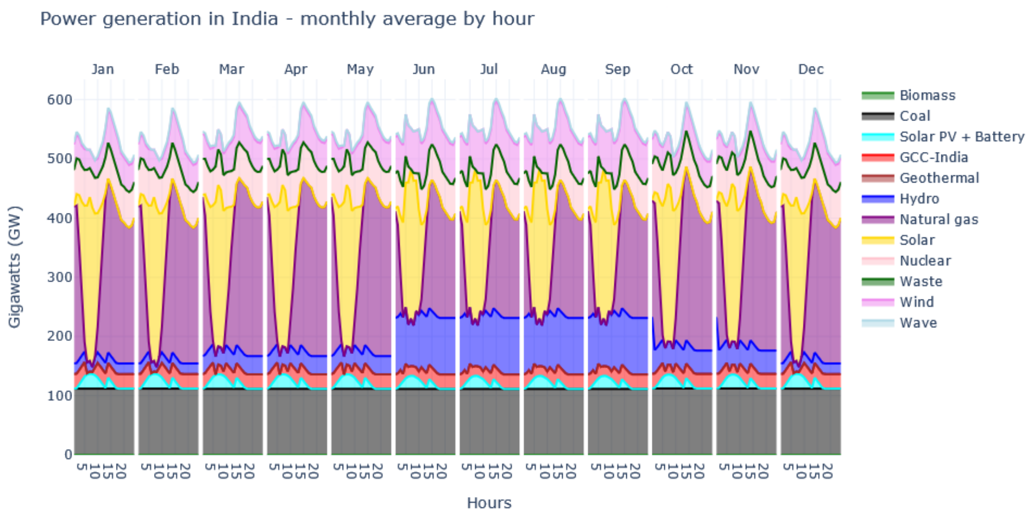

Figure 9. Hourly power generation for India in 2050 - monthly average

The model results show that (i) the battery technology is installed to its maximum capacity of 60 GW and (ii) that it does not substitute the installation of the GUI. Instead, both the interconnector and solar PV+Battery technologies work in tandem to meet the peak load demand India. With a battery technology, the peak load demand between 19:00 and 21:00 can be met by stored electricity from solar power generation earlier in the day.

Financial Feasibility

The net-present-value (NPV) of the proposed interconnector project is shown in **Figure 11**. For almost all scenarios, the project NPV is negative. The strongest relationship is between NPV and interconnector (IC) unit cost. NPV decreases with increase in interconnector unit costs. The social discount rate also shows some relationships with the NPV of the interconnector. This could be because, at lower social discount rates, the penetration of renewables is higher, which increases the arbitrage opportunities across the interconnector.

Care must be taken when interpreting these results. The financial model builds on the projections of the technoeconomic model, relying on the technoeconomic model's determination of installed capacity, installation date, trade volume, and marginal price difference. So, while the revenue side of the interconnector's cashflow is similar between the technoeconomic model and financial model, and while both models use the same discount rate, the financial model also includes additional costs such as debt interest during construction and financing fees. Critically, the technoeconomic model is constrained such that the interconnector covers its costs, not that it is a profitable investment. It is fully expected that the financial model shows a less optimistic case for the interconnector given the same scenario.

As the technoeconomic model seeks to minimise total system costs, it will not necessarily choose capacities which allow for maximum profitability of the interconnector. As shown, in almost all scenarios, the maximum size available is chosen for the interconnector. This suggests that the presence of the interconnector substantially reduces total system costs, but the negative NPV shows that the interconnector itself is currently capturing these benefits. In almost all scenarios, the project IRR and equity IRR are positive, see Figure [REF]. If more of the benefit provided by the interconnector would be accrued by the interconnector itself (i.e., if its revenue were increased), or, if it was able to secure concessional and government financing and grants which lowered its costs of capital sufficiently, then the interconnector would be investible as-is.

In order to be aligned with the technoeconomic model, the interconnector revenue is calculated using a time-of-use tariff based on the difference in marginal costs between the connection nodes on either side of the interconnector. This means that as the interconnector grows in capacity, this marginal difference becomes smaller and the interconnector's revenue stream becomes smaller. If the interconnector were more constrained in size, the arbitrage opportunity might not be cannibalised. It is expected that the investment case for a smaller interconnector would be more favourable.

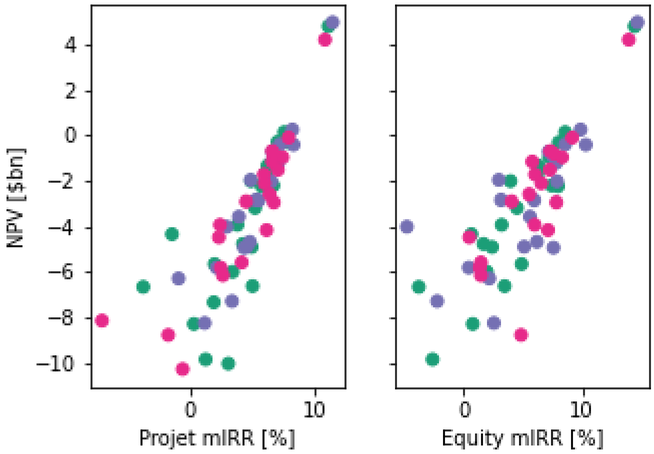

Figure 10: Relationship between Project and Equity mIRR and NPV

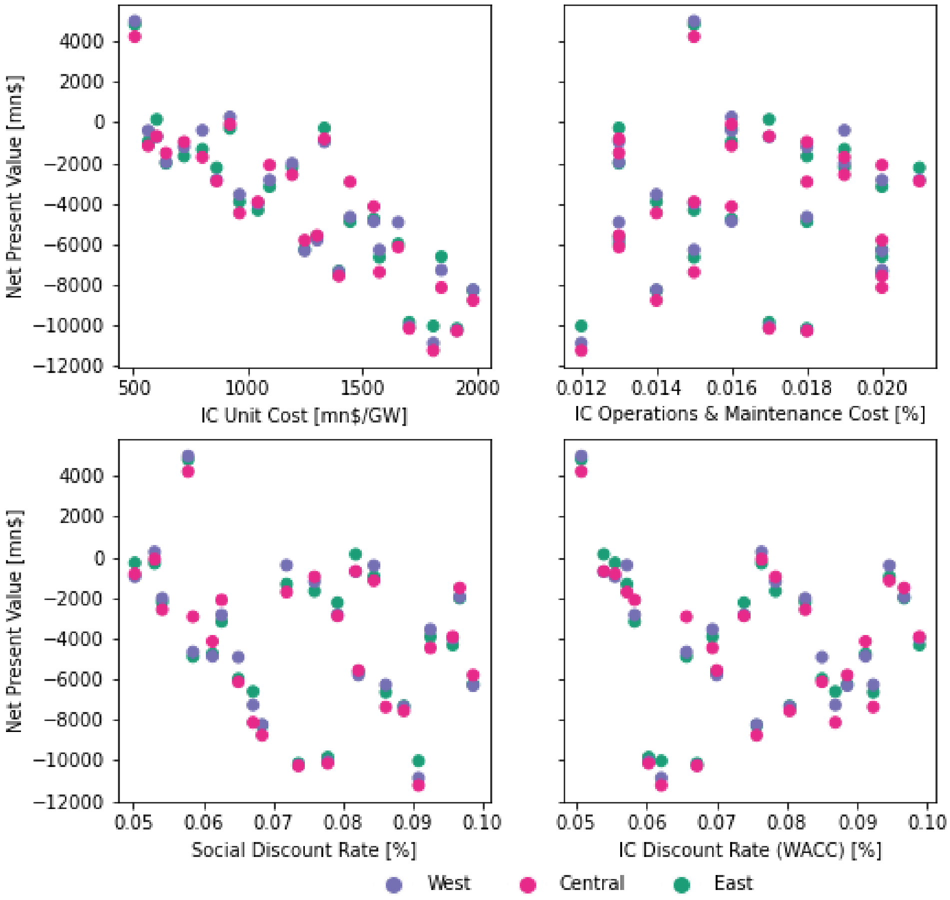

Figure 11: Project net present value dependence on scenario parameters

Risk Sensitivity

Project investibility is tested for sensitivity against a number of risks, as presented in Table 4. These risks reduce to proxies effecting the interconnector's cashflow: CAPEX overruns, OPEX overruns, and revenue impairment. Each scenario's sensitivity to these risks is show in Figure 13.

Scenario NPV is predictably affected by each of CAPEX, OPEX, and revenue. Increases in revenue and reductions in CAPEX are able to make some scenarios NPV-positive, and the opposite is also true. The observed effect of OPEX interdiction is considerably smaller than that of CAPEX and revenue. The overall findings however, are robust to the risks highlighted here.

Conclusions

The techno-economic case for a GCC-India interconnector is clear: an interconnector is part of the least-cost 'optimal' power system in 64 of the 75 scenarios studied. Bi-directional trade between the two regions can contribute towards reducing costs and emissions across a range of scenarios. The trend of electricity flows gradually shifts from the India->GCC direction in 2030 to the other way around by 2050. The overall trade volumes are influenced by the location of the solar PV farm; locations further to the west contribute towards higher trade volumes in the GCC->India direction. Of the cost variables considered in the study the overall (social) discount rate is most strongly correlated with the interconnector trade volumes. As the discount rate increases, renewable power generation technologies are considered less techno-economically favourable. This is in turn leads higher electricity flows in the GCC->India direction. Finally, the role of storage was found to complement rather than substitute the GUI, with both combining to towards meeting India's peak load.

The financial case for the CCG-India interconnector is less clear. Of the projections developed for the scenarios from the technoeconomic model, only a small number are immediately investible. However, the non-investible scenarios show a shortfall in investment attractiveness consistent with the difference between the technoeconomic models and financial models. Better harmonisation of the technoeconomic and financial models will clarify the conditions for investibility of the interconnector. It is also expected that a smaller interconnector will be a more attractive investment opportunity, for a trade-off in total system cost reductions.

This study aimed to identify whether a combined techno-economic and financial case exists for an interconnector between India and the GCC across a broad range of scenarios. There are however additional aspects to consider – that were outside the scope of the current study – in order to provide a more comprehensive picture. These include energy efficiency measures in India, evolving demand patterns, coal with CCS, and expanded trade with South-East Asia. Further, the study can be aligned more closely with state and national policies in relation to power procurement strategies, wheeling charges, grid integration, and financing options.

The starting point of this analysis was that GCC-India interconnector would result in desirable outcome of increasing the share of India's electricity demand met by solar PV generation. This was confirmed by the techno-economic model. However, two other aspects from the modelling results were somewhat surprising and warrant further analysis: 1. Significant electricity flows in the India->GCC direction; and 2. Unfavourable financial case for the GUI. Both these aspects are sensitive to factors such as cost of capital, electricity subsidies etc. One avenue for further exploration is to identify policy/market conditions to encourage such 'system-optimal' investments that are risky from an investor's perspective. Further, expanding the geographic scope could also alter the overall feasibility of the GUI. For instance, the GCC is well-positioned to act as an electricity trading hub between South-east Asia, India, and the African power pools. This study provides an initial analysis of the GUI. However, further analysis of the aspects described above would help provide a more comprehensive picture.

Author contributions

Conceptualization, M.H. and A.H.; Methodology, M.H., A.H., A.S., and L.K.; Software, W.U.; Validation, A.S., M.W, L.K., and S.S.; Formal analysis, X.X.; investigation, X.X.; resources, X.X.; data curation, X.X.; writing—original draft preparation, A.S., L.K., S.S., .; writing—review and editing, X.X.; visualization, X.X.; supervision, X.X.; project administration, X.X.; funding acquisition, Y.Y. All authors have read and agreed to the published version of the manuscript.

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Disclaimer

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Appendices

Appendix A: Model structure

A linear optimisation model of a combined India-GCC power system was developed using OSeMOSYS, an **open-source** energy system modelling tool. The model scope was as follows:

<u>Geographic scope (14 regions):</u>

Bahrain, Kuwait, Oman, Qatar, Saudi Arabia (4 regions), UAE

India (5 regions)

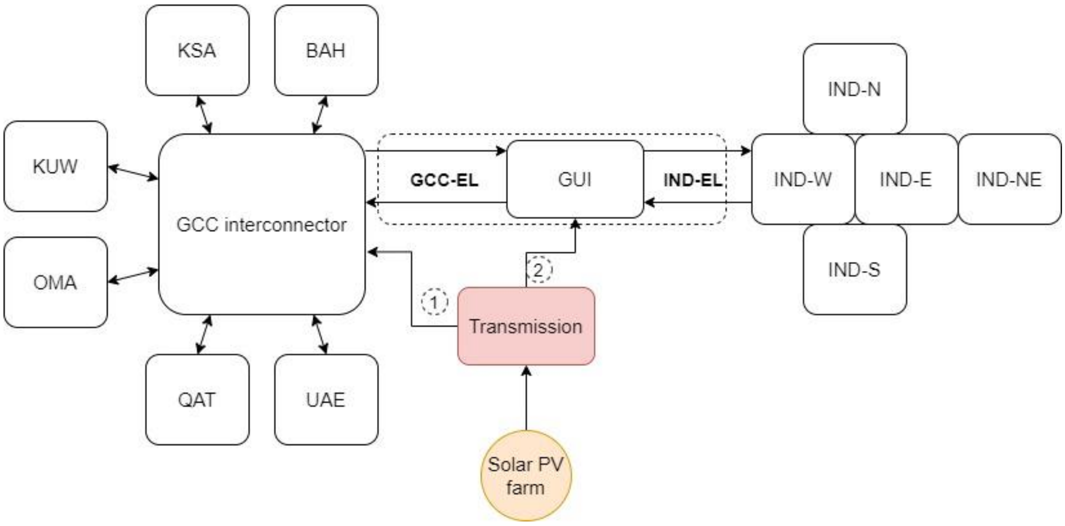
<u>Powerplant technologies (14 types):</u> Coal, Natural Gas, Oil, Diesel, Waste, Biomass, Hydro, Geothermal, Wind, Solar photovoltaics, Concentrating Solar Power, Wind, Wave, and Nuclear

<u>Time resolution (96 representative 'time slices'):</u> 24 hours, 4 seasons

<u>Model horizon:</u> 2015-2050

A simplified structure of the model is shown below.

Figure 12. Simplified model structure



Appendix B: Scenario table

Table 5. Summary of twenty-five 'samples' covering the ranges of cost variables

Sample	CapitalCost	DiscountRate	DiscountRateIdv	FixedCostPercent
0	507	5.78%	5.07%	1.5%
1	1703	7.78%	6.03%	1.7%
2	1548	6.13%	9.12%	1.6%
3	1396	8.87%	8.04%	2.0%
4	921	5.30%	7.64%	1.6%
5	1445	5.85%	6.57%	1.8%
6	1573	8.61%	9.23%	1.5%
7	1301	8.22%	7.00%	1.3%
8	1981	6.84%	7.57%	1.4%
9	963	9.25%	6.94%	1.4%
10	1043	9.57%	9.89%	1.5%
11	565	8.44%	9.46%	1.6%
12	1192	5.41%	8.26%	1.9%
13	801	7.19%	5.72%	1.9%
14	602	8.18%	5.39%	1.7%
15	1655	6.50%	8.50%	1.3%
16	1911	7.36%	6.72%	1.8%
17	1808	9.08%	6.21%	1.2%
18	642	9.67%	9.67%	1.3%
19	1094	6.26%	5.83%	2.0%
20	1333	5.02%	5.55%	1.3%
21	1247	9.86%	8.86%	2.0%
22	863	7.92%	7.39%	2.1%
23	1843	6.71%	8.69%	2.0%
24	721	7.59%	7.84%	1.8%

Appendix C: Risk Sensitivity

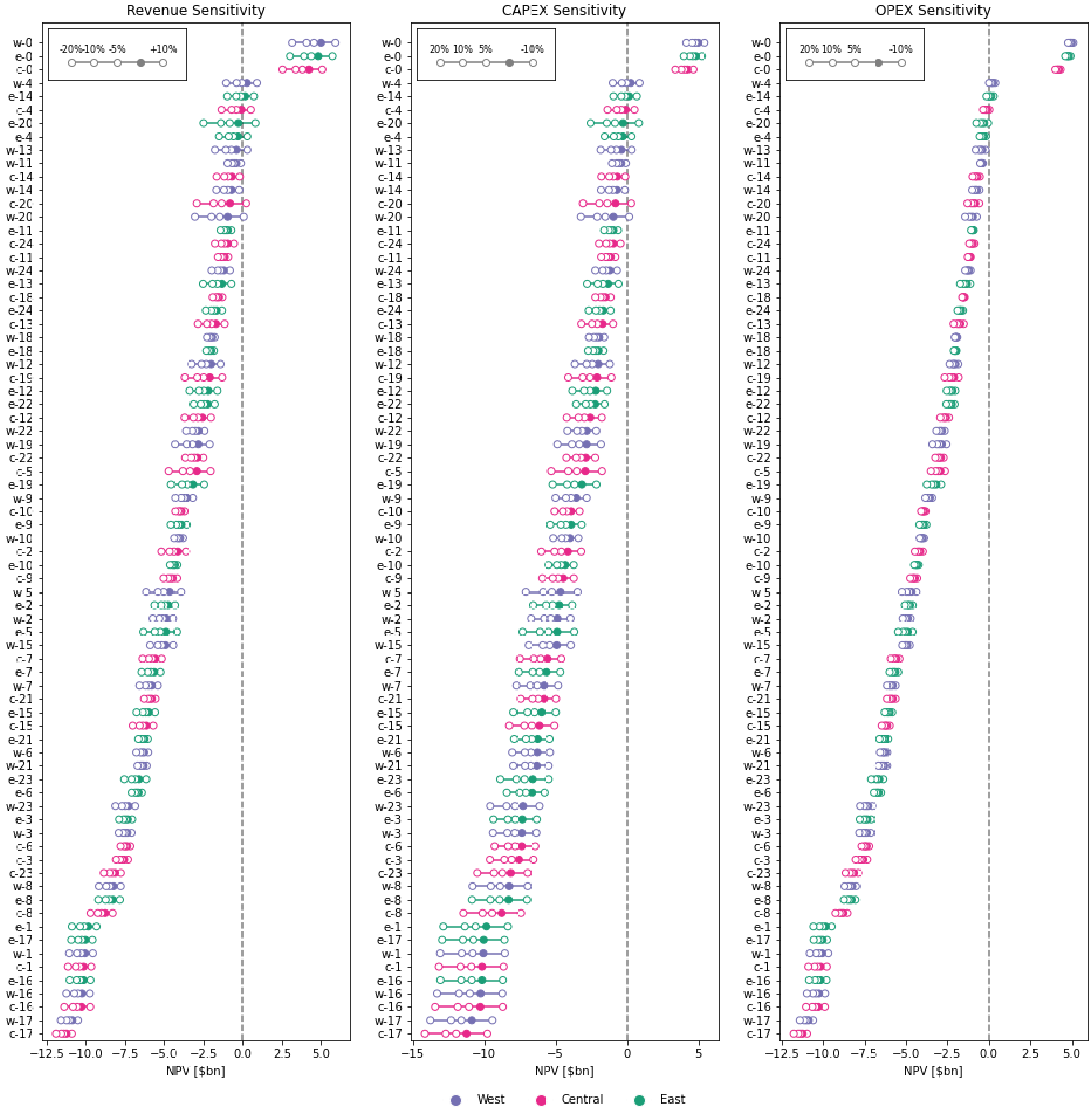


Figure 13: NPV impairment due to interdiction of CAPEX, OPEX, and revenue