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Cross-Border Interconnectors in South Asia: Market-Oriented Dispatch and Planning

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ABSTRACT Regional trade in South Asia has progressed well over the last decade to exceed 3 GW in interconnection capacity, connecting India with Bhutan, Bangladesh and Nepal. We present an analysis of the benefits of the next 10.6 GW of interconnection capacity under construction and planning stages across four major corridors connecting five countries, including the proposed HVDC interconnector between India and Sri Lanka. It is important that these interconnectors are assessed not only for long-term benefits as part of a least cost portfolio of investments, but also for short-term, market-based benefits that can be gained from new opportunities for cross border electricity trade (CBET) in India's power exchanges. The Electricity Planning Model (EPM) is developed for analysis of regional markets. A combination of market price driven short-term dispatch analysis and long-term planning optimization (for 2019-2035) is conducted using EPM. The analysis shows a strong economic case for development of a South Asian Regional Electricity Market (SAREM). Conservative estimates of (discounted) benefits exceed \$1 billion accrued over only 10-12 years for each of the incumbent four major corridors. The short-term analysis using historic spot prices in the Indian Energy Exchange (IEX) also reveals a strong case with <u>annual</u> benefits in the range of \$100-400+m pa for these corridors. The model is made available to system operators and planners in the region and used for building their capacity to develop further assessment and inform policy dialogues.

INDEX TERMS Cross-border interconnection, dispatch optimization, mixed integer programming model, long term planning, regional electricity market.

I. INTRODUCTION

Cross-border electricity trading (CBET) in South Asia's eastern region (Bangladesh, Bhutan, India, Nepal, and Sri Lanka–BBINS) took place at lower voltage levels in only a few countries before trade at scale started between India and Bhutan from October 2002. Subsequent additions of interconnectors between India-Bangladesh in 2013, and more recently India-Nepal, built the requisite transmission infrastructure to expand CBET. It created the momentum for greater scale, albeit South Asia remains one of the least connected regions in the world. The past decade has observed a transition from a sense of disbelief that CBET could happen, to demonstration of its feasibility through initial investments, now to a discussion on scaling up in terms of volume, terms of trade and diversity in trading counterparts. Fig.1 shows that the existing transfer capacity of 3.1 GW will double soon when 3.6 GW of capacity under construction is completed. Another 7 GW capacity is in the planning stage that would quadruple existing capacity by 2025. These projects, totaling 10.6 GW, will form the nub of the South Asian Regional Electricity Market (SAREM). In the long term, additional 49 GW capacity is expected to fully integrate India-Nepal (25 GW) and India-Bhutan (24 GW) grids. Trade is gradually evolving with national policies, as reflected in the latest CBET guidelines and regulations from India [1], which makes it possible to trade via India's power exchanges, as well as evolving institutional arrangements in neighboring countries. The CBET guidelines were originally put in place in 2016 and revised in December 2018. The revised guidelines allow for participation of neighboring countries in coordination with a "Designated Authority" in India's Central Electricity Authority

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[1]The opinions and views presented in this article are his own and do not necessarily represent the views of the International Bank for Reconstruction and Development/World Bank or its affiliated organizations.

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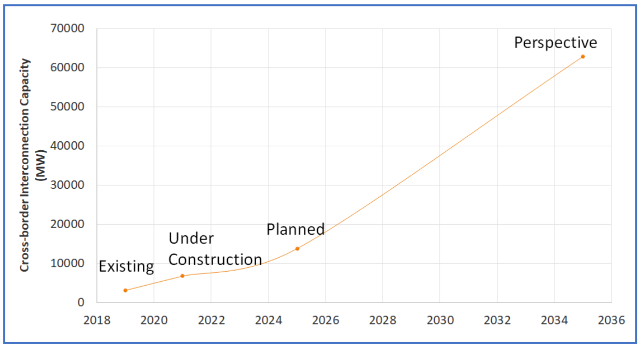

FIGURE 1. Cross-border interconnection capacity projection (MW).

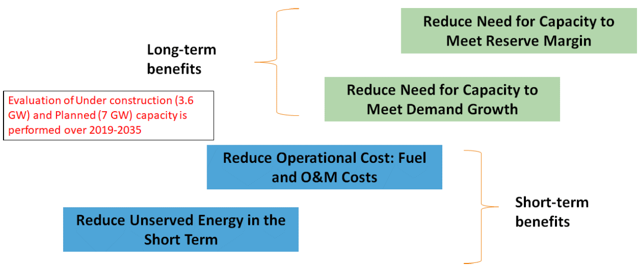

FIGURE 2. Short-term and long-term benefits calculated using EPM.

who would be responsible for planning, monitoring and commissioning of cross border transmission lines for import and export of electricity from India. While the CBET framework certainly does not preclude the possibility of other countries setting up their own wholesale markets, it allows entities nominated by those countries to participate in the power market in India, including competitive procurement of power via trading companies licensed in India, and take advantage of a competitive, transparent and dynamic prices as well as the flexibility associated with a short-term market based trading arrangements offered by India's power exchanges. Regional power markets at varying stages of development in Africa and Central America are trading at volumes that may be small relative to larger participants' power systems. However, these trades capture potentially transformational benefits for smaller systems and from which larger systems can share benefits in terms of trading surpluses, sharing reserves, strengthening resilience, balancing variable renewables, improving fuel mix, increasing competition or supplying peak demand. Bangladesh has partly engaged in market-based trading and it is envisaged that smaller countries like Bhutan and Nepal would benefit from the updated CBET framework. In order to support the development of a regional market, it is important that efforts are made to identify and assess new interconnectors:

(a) from a short-term market perspective i.e., trade along these interconnectors could be (partially) supported by market prices as envisaged in the CBET framework. Participants from all countries will need to trade via power exchanges, e.g., Indian Energy Exchange (IEX); and
(b) over the longer term power assets form part of a least-cost portfolio of generation and transmission for the region as a whole. Most new generation assets are likely to continue to secure financing on the basis of long term PPAs, most of which can be competitively procured. Short-term merchant opportunities might be introduced as trade in power exchanges and other market reforms mature. For CBET, this will require development of a coordinated and to the extent feasible harmonized, or even common, regulatory regime to identify future interconnectors and allocate costs among the countries.

A. OVERVIEW OF LITERATURE

1) SOUTH ASIAN REGIONAL INTEGRATION STUDIES

There have been several studies, especially over the last decade, that provided the necessary impetus for the current state of interconnection. The 'Vision 2020' study [2] and the South Asian Regional Trade Study (SRETS) [3] had set the initial tone for integration. The analytical studies [4], [5] that accompanied these demonstrated the value of trade from six interconnectors that were at different stages of development in South Asia during 2012-2014. These analyses showed for the first time that CBET benefits can be as high as $5 billion pa in the near term primarily because of the hydro development in Nepal (with 42 GW economic hydro potential) and Bhutan (24 GW potential), that provided further confidence to the stakeholders. World Bank [6] initiated a long-term planning exercise that showed the massive long-term benefits from 'unconstrained trade' to continue at $5-7 billion pa for the next 20 years. USAID's South Asia Regional Initiative for Energy Integration (SARI/EI) has also been active in building consensus among the stakeholders for several years including analytical studies. Recent findings from SARI/EI [7] confirms significant long-term benefits of such integration including large capital expense (capex) savings for the region of $17b as well as cumulative CO_2 savings of 120 mt by 2045. More recently, NREL conducted two studies for India-Nepal [8] and India-Sri Lanka [9]. The first study [8] was conducted for 2022 and estimated a savings of $359 million for the year from 4.5 GW hydro development in Nepal. The second study [9] conducted for 2025 estimated savings from India-Sri Lanka line at $180 million (for one year).

2) REGIONAL INTEGRATION STUDIES IN OTHER REGIONS

The topic of optimizing cross-border trade dates back several decades. Manne [10] and Rogers and Rowse [11] among others used optimization models to analyze the benefits of trade between US and Canada in the eighties. The genesis of cross-border trade in South Asia followed very similar models and methodology, albeit these initially focused on improving trade *within* India among its states/provinces that were practically independent until the early nineties. Parikh and Chattopadhyay [12] demonstrated that the benefits of an integrated Indian national grid can be as much as $2b pa (in 1990). Regional connectivity within vastly improved since then among the Indian states that are as big as countries in many other parts of the world, including a robust 765 kV network and over 100 GW of inter-regional transmission capacity that exists today.

Europe sets the global standard in many ways for regional integration since 1996 following the EU vision of a single European market. Booz and Company [13] had estimated the benefits of such integration at Euro 2.5-4.0 billion pa once the full market coupling is in place in the EU. Pollitt [14] provides a more sobering account of some of the arcane challenges in estimating these benefits including the influx of heavily subsidized renewables (RE) that may in fact reduce these benefits considerably.

In the developing world, Africa has seen considerable efforts led by the donor agencies to interconnect power systems to support development of scale-efficient regional generation projects including mega hydro in the past, and solar/wind in more recent years. World Bank [15] led the '*SAPP Pool Plan*' - an extensive planning study for Southern Africa using the PLEXOS model covering longer term (2017-2040) benefits associated with avoided capacity and full integration. It concluded that full integration of Southern African Power Pool (SAPP) would result in cumulative savings of over $42 billion in investment and operating costs for the region till 2040 over the business-as-usual case where each country implements its own national power development plan. Eastern African Power Pool (EAPP) master plans of 2014/15 [16] showed that 12 new interconnectors can yield discounted total benefits of $27b over 2013-2038 which is 4.38 times the cost of such developments. Middle East and North Africa has also stepped up its efforts lately to be more interconnected with potential savings estimated at $12 billion over 2020-2030 [17].

As interconnectivity within regions improved and with the advent of super-highways including high capacity HVDC/HVAC links and subsea cables, there are also visions that beyond regions including "global super grids" [18], [19].

3) RELEVANT MODELING ISSUES

Shahidehpour [20] points out the challenges that "*clouds transmission planning*" and makes it difficult to justify transmission investments even in an advanced system like the USA. The central issue is that benefits of transmission directly depends on that of cost-efficient generation. This in turn means an integrated assessment of generation and transmission in a market environment is essential. References [21]–[24] amply demonstrate how such a framework can be developed, combining generation and transmission expansion planning models [21], [22] to co-optimize transmission [23] in a market environment [24]. These studies consider large-scale mixed integer programming models to evaluate simultaneous expansion of both systems, and thereby select transmission options that are most beneficial. Sauma and Oren [25] bring in additional complexities in a market environment, namely, dominant generators affected by transmission investments *can* respond to such decisions that need to be captured in an equilibrium model. Lin [26], on the other hand, demonstrates how sound transmission investment decisions (between PJM and MISO areas) can be supported to show both economic benefits of removing congestion and reliability benefits that form the bedrock of transmission regulation in many systems. References [27]–[30] deal with some of the technical modeling challenges around transmission especially around the issue of transmission system security. Zhang *et al.* [27]–[28] discuss the challenges around representation of AC load flow constraints in an integrated generation-transmission model including approximations that perform reasonably well. Qiu *et al.* [29] discusses the need for a probabilistic assessment to capture the trade-off between economic benefits and system security to reduce the impact of extreme events. Finally, Meng *et al.* [30] proposes a framework to consider operational uncertainties that may arise from connecting large-scale offshore wind farms, using alternative AC and DC transmission representations.

Although there is a rich literature on the topic including prior case studies for South Asia, these can be complemented by more (a) market oriented analysis in the region; (b) a RE policy informed least-cost analysis; and (c) sufficiently aligned capacities in the utility planning groups to undertake these analyses on a sustained basis. These issues need to be addressed for planners in the region to introduce CBET considerations in national master plans, and devise a cross-border mechanism that can be leveraged to exchange information and analysis. Such analysis will encourage shared perspectives on the role of CBET and prioritization of CBET interconnectors. This is a critical enabler to form a win-win regional master plan and unleash more of the massive potential for RE (including hydro) in the region.

B. SCOPE OF THE PRESENT WORK

The present analysis focuses on the economic benefits of the projects in the medium term covering four major corridors from India to its neighbors namely, Bhutan, Nepal, Bangladesh and Sri Lanka. The objectives of the present analysis include: (a) introducing a market-oriented analysis of short-term trade to assess the benefits that each planned interconnector would have earned trading through the Indian market as envisaged in the CBET guideline [1]; and (b) a long-term planning analysis over 2019-2035 to simulate SAREM including the 175 GW renewable policy scenario in India [5], [6].

The specific contributions of the study are as follows:

(a) It introduces the EPM model that combines a generation-transmission planning models with representation of spinning reserve co-optimization, advanced RE policy and technologies such as CSP and battery storage. It is a state-of-the-art planning tool cast as a single optimization problem, fully documented and the source code is available for direct use or enhance/adapt the current model for specific situations;

(b) The short-term modeling analysis presented here combines market prices and dispatch in a single framework suited well for a region where markets have not been introduced in most countries other than India. Part of the objective of this analysis is to give shape to the ongoing stakeholder discussions to implement CBET guidelines [1] and build capacity among the utility planners, generators, DISCOMs and system operators to understand the benefits of trading. EPM is being used by some of the utility planners for this purpose;

(c) Simulation of RE policies together with cross-border power trading that is very useful in understanding how a target in one country (e.g., the massive 175 GW RE target in India) can benefit its neighbors; and

(d) It also marks the first application of this market-oriented planning methodology for five countries in South Asia in collaboration with the system operators and power ministries in the region with the data/assumptions developed in collaboration with, and vetted by, the former group.

II. MODELING METHODOLOGY AND IMPLEMENTATION

A. OVERVIEW OF THE EPM MODEL

We use the Electricity Planning Model (EPM) [31].[2] The model was developed by the Power System Planning Group of the World Bank in 2015 and since then have been implemented for over 60 developing countries to inform investment decisions and policy analyses. It is largely deployed for World Bank's internal analysis and for capacity building exercises for utilities and ministries conducted by the Bank. It has also been adopted by 10 utility planning groups through the Bank's Technical Assistance projects. The model has been used extensively for other regional markets such as Central Asia, Middle East, North Africa, Eastern Africa, Southern Africa and the Western African Power Pools. The model has capabilities for expansion in the long-term as well as short-term dispatch analysis. References [32]–[37] reflect some of the salient features of the EPM. The model:

1. Performs a least-cost expansion of both generation and transmission expansion over multiple years and zones;
2. represents a full range of technology options including CSP/thermal and battery storage [32] as endogenous capacity decisions;
3. Fully captures variability of solar and wind including short, medium and long-term (inter-annual) variability [33] as well as their impacts on spinning reserve;
4. Co-optimizes the allocation of spinning reserve taking into consideration variability of solar/wind;
5. Recognizes upstream fuel constraints and linkages to coal mine operation and retirement, if relevant. The model also considers seasonal hydro availability limits;
6. Considers demand side management including demand response and energy efficiency options [34];
7. Allows representation of a range of policy options including carbon, renewable and energy efficiency targets;
8. Can consider uncertainties in multiple parameters through a stochastic programming variant of the model as well as a Monte Carlo module;
9. Can be used as part of a Robust Decision Making (RDM) framework to analyze issues around pervasive uncertainty typical of fragile countries [35], [36]; and
10. Can be used for analysis of resilience of power system combining some of the features discussed above [37].

The detailed formulation of the core mixed integer linear programming model is included in the Annexure. Some of the features listed above, namely items 8-10 have not been employed for the present case study, but the details of these can be found in the references cited. The model decides on new generating units/storage (and transmission lines as an option) and (economic) retirement of existing units as a set of integer variables. There are associated operational decisions on transmission line flows, spinning reserve for different classes for each generator, emissions, fuel supply and storage. Demand representation in the model is done through a set of chronological (hourly) load profile for a set of representative days that may be selected using a clustering technique. The objective function of the optimization is the discounted system cost that includes capital costs for generation, transmission, storage, variable costs including fuel and penalties on unserved demand and reserve. Constraints in the model include eight major blocks (and the Annexure follows the same order):

1. Demand-supply balance and transmission flow limits;
2. System security including capacity reserve margin and spinning reserve requirements;
3. Generation related constraints including ramping, joint provision of energy and spinning reserve, seasonal hydro energy limit, fuel limit, etc;
4. Special constraints that enforces renewable energy availability profile, and concentrating solar plant module-specific balances;
5. Capacity balance over the years;
6. Storage operation related constraints;
7. Investment related constraints including annual build limit and limit on maximum capital; and
8. Environmental policy related constraints including carbon limits.

There are other aspects of the model that are not listed here including a stochastic programming formulation that allows a better representation of uncertainty issues including climate resilience, demand response, interannual variability of RE, exogenous spot price driven dispatch/flows, upstream linkage to fuel supply chain. These aspects are covered in more detail in [32]–[37]. The ability of EPM to endogenously model thermal/battery storage [32] taking into consideration uncertainties around renewable energy availability [33] and spinning reserve requirements it imposes on the system [32]–[33] using a stochastic formulation [34], are useful in making a comprehensive representation of variable renewable resources. Absent a proper representation of spinning

[2] The model is implemented in GAMS with an Excel front-end and the source code is available on request through the ResearchGate link noted in [31]. The model will also be made available through IEEE Access.

TABLE 1. Capacity of interconnectors analyzed (MW).

Interconnected Nations	Under Operation	Under Construction	Under Planning
India-Bangladesh	1200	340	1000
India-Bhutan	1350	2900	-
India-Nepal	600	400	5000
India-Sri Lanka	-	-	1000
Total	3153	3640	7000

reserve, for instance, the true cost variability of solar/wind imposes on the system will not be captured. The fact that solar and wind profile is not 'fixed' i.e., predictably variable, also needs to be reflected through multiple profiles commensurate with the inter-annual variability of these resources. As the hour-by-hour availability of solar and wind as well as the energy over a period can vary considerably across alternative profiles, capacity planning for the system needs careful attention to cover for these uncertainties. EPM introduces the concept of a 'renewable contingency' [33] that allows the planner to consider the risk around variability of solar/wind that can be tolerated. At one extreme, the lowest availability of solar/wind for a given hour across multiple solar/wind profiles from different historic years/forecasts could be treated as 'firm'. A more balanced approach would be to use a contingency-constrained version of EPM that explicitly captures all, or a select set of, solar/wind profiles and let the model decide what part of variable renewable capacity *should* be treated as firm and complement it with non-renewable capacity/generation. As more solar/wind capacity/generation is included in the generation mix, it would increase the spinning reserve requirement in the system. Solar/wind variability may be particularly acute in some hours of the day (e.g., morning and evening ramp for solar and very low availability of wind during the pre and post-monsoon months). These low availability patches are modeled as renewable contingency constraints in the optimization. Costs associated with these constraints and with added spinning reserve, start building up as the share of renewable increases and would at some point start limiting the volume of renewables. EPM's ability to model multiple renewable profiles, contingency constraint and spinning reserve implications, allow us to assess the optimal level of variable renewables in the generation mix.

The ability of the model to deal with all of the core requirements of short and long-term planning has enabled the users to adapt the model to a range of country-specific situations and problems.

B. IMPLEMENTATION FOR THE SOUTH ASIAN REGION

The current implementation for SAREM covers the incremental benefits of specific interconnectors "under planning" (see the last column of Table 1), but also assumes the presence of the capacity already under operation and under construction.

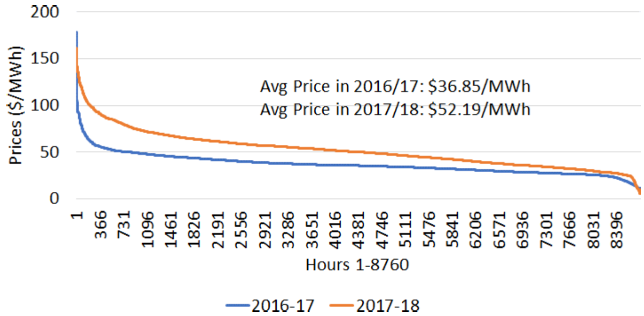

FIGURE 3. Hourly spot prices on Indian Energy Exchange ($/MWh).

EPM analysis is conducted without and with each incumbent planned interconnector to calculate the benefits in short-term and long-term (Fig. 2):

The analytical approach comprises two components: (a) short-term dispatch analysis; and (b) long-term planning.

Short-term analysis: involves running an hourly dispatch covering all 8,760 hours of a historic year with the observed spot prices for the Indian Energy Exchange (IEX) (Fig. 3), as an input to the model to drive dispatch decisions in each country, and trade decisions between India and its trading partner. The model is set up as a linear program (LP) to minimize the short-term production cost, plus import costs less export revenue of a country. The model dispatches its generators in merit order, but allows for: (a) import when the marginal cost of generation in Bangladesh is higher than that of (loss-adjusted) price in IEX for the hour; or (b) export if the marginal cost is lower than the market price in India that can be earned. As noted already, trade prices are exogenous to the model set at historic prices. However, the model uses a piecewise linear approximation of a "bid curve" around the observed market clearing solution (based on IEX aggregate demand-supply bid curve data). This in effect means if Bangladesh exports to India, the price earned by it will drop as the export volume goes up. On the other hand, import prices will go up as the import volume goes up. The process mimics a market-based trade that a country would do on a day-ahead basis or in real-time. The dispatch model observes constraints around import/export limit, fuel limit (e.g., gas in Bangladesh) and hydro energy storage limits (in Nepal and Bhutan). A key assumption underlying this analysis is that the trading partner sells and buys in the "residual" market of the Day Ahead Market (DAM) in India. Trading will take place at the margin of Area Clearing Price (ACP) after IEX has cleared, i.e., demand in the Indian market is met first in the model.

The dispatch model is implemented for each individual country separately to assess the benefits of each incumbent interconnector at a time. In effect, we answer the question: *would this interconnector be beneficial had it been available in 2017/18 and/or 2016/17?* These two pricing regimes/years are selected to represent years with the highest volume of trade. Further, 2017/18 represents a high price scenario and 2016/17 represents an average price counterpart. The analysis is limited in that it captures only operating expense (opex) and any unserved energy savings in the two trading countries.

Long-term analysis: a least-cost planning analysis that fully captures all of the components of benefits including savings in capex that may be realized with capacity reserve as well as energy shared across the countries. The long-term analysis follows a least-cost planning methodology and does *not* use IEX spot prices to drive the trade decisions. All five countries are modeled together covering 1,100 generators and 34 zones. The model is set up for 2019-2035. Discounted benefits for each of the interconnector is calculated by allowing each new incumbent interconnector at a time. This in effect does allow partial multilateral trading for cases like Nepal, Bhutan and Bangladesh where interconnection already exists, except that the analysis considers one interconnector at a time to assess its stand-alone benefit.

A challenge to the modelling is the treatment of policy developments influencing national generation capacity mix. For example, India's 175 GW RE target (by 2022) may result in significant surplus generation capacity in India for some time. This, in theory, may reduce its need for import, especially hydro from Nepal/Bhutan. On the other hand, flexible storage hydro development in Nepal/Bhutan may also complement variable RE in India. Since the bulk of CBET benefits rest on India (and to a lesser extent Bangladesh) importing hydro power [4]–[8], it is an important test to see if the benefits remain as India embarks on a path of high variable renewable electricity (VRE) growth. This issue has not been addressed in the previous analyses. The long-term analysis contributes to the rising body of related studies also by offering a check on whether the benefits remain significant in light of selected demand-supply-policy developments in the region.

EPM, especially the long-term planning version of the model, is computationally intensive because it covers multiple years. The SAREM implementation of the model has 11.5 million decision variables, 8.3 million constraints and 38 million non-zero elements in the constraint matrix for a 17-year planning period (2019-2035). We have used the GAMS/CPLEX (version 12.8) solver – a powerful commercial grade LP/MIP solver on a i7-7600U CPU 2.80 GHz processor and 16 GB RAM. The core model in LP mode solves in 58 minutes.

III. ANALYSIS OF INTERCONNECTION BENEFITS

A. SHORT TERM MARKET PRICE DRIVEN ANALYSIS

As part of the short-term analysis, we have selected a set of scenarios for each interconnector to develop a range of benefits. Table-2 shows the short-term benefits of the proposed Sri Lanka (SRI)-India link, if the power flow on the link could be bought and sold on the IEX at observed prices in FY 16/17 or FY17/18 under different hydrology conditions in SRI, namely, Avg (4050 GWh pa), High (4834 GWh pa) and Low (3489 GWh pa). All other things being equal, high IEX prices and high availability of hydro in SRI, reduce the benefits to SRI as import is less attractive.

TABLE 2. Sort-term benefit of trading: IND-SRI link.

	Total Benefit	Sri Lanka (GWh)		Benefit ($m)	
	($m)	Import	Export	SRI	India
AvgHyd 17/18(H)	383	5469	1359	163	220
AvgHyd 16/17(L)	406	5548	1293	214	192
HighHyd 17/18(H)	326	4987	1661	94	231
HighHyd16/17(L)	339	5073	1602	139	200
LowHyd_17/18(H)	422	5794	1123	217	204
LowHyd_16/17(L)	453	5871	1054	277	176

As the table shows SRI is expected to be primarily importing power through the link. However, the link would also allow SRI to support demand in India when demand-supply gap is tight there resulting in high spot prices. In fact, as a predominantly hydro system, SRI has cheap resources that can be immensely beneficial to curb volatility in IEX. Model results reveal that is the case whenever southern region prices on IEX go above \$70/MWh which occurred in FY 17/18 for nearly 1000 hours (Fig 3). On the other hand, model results show that SRI could rely on cheaper thermal power ($<$ \$50/MWh) from India which is available from IEX for majority of the year. On balance, the link can generate very significant savings in the range of \$326-453 million for a single year. Even at the lowest end when IEX prices are high and SRI has a very good hydro year, the link is utilized at 70% and yields \$326 m in benefits that can justify more than half of the link's cost in a single year. The high end of benefits (\$453m) occurs when SRI has low hydro availability and the prices on the Indian side is relatively low. This again highlights the fact that the SRI demand has outgrown its hydro power and rely on high cost thermal to meet the demand on the margin that could be avoided through imports.

Allocation of benefits to each country, shown in the last two columns of Table 2, are derived by aggregating hourly savings for each country. It reveals a slightly arcane fact that the short-term benefits – even for a case when flows are dominant in IND$\rightarrow$SRI direction – enjoyed by the two countries are quite comparable. SRI in fact has a slightly lower share of 46% of the total benefits on average across the six scenarios and may receive as low as 29% of it when it enjoys a good hydro year. This is surprising given India receives 1,384 GWh from SRI on average across six scenarios, or roughly one-quarter of its export to SRI. However, these SRI$\rightarrow$India flows occur at a time when IEX prices are high and the southern region of India indeed has seen some high degree of volatility due to transmission constraints across the north-south corridor (in India). Therefore, the marginal benefit of these transfers to displace some of the high-priced bids on IEX can be extremely high, even if it occurs for a limited number of hours. As Fig.4 shows, there is a significant seasonal variability of benefits to Sri Lanka which virtually disappears during March/April before the monsoon when wind/hydro

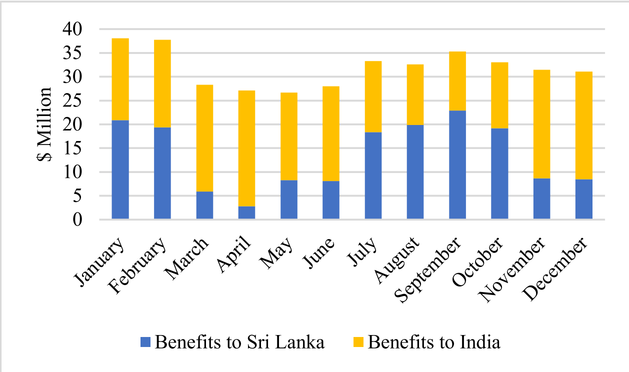

FIGURE 4. Seasonal variability of benefits [Scenario AvgHyd 17/18(H)].

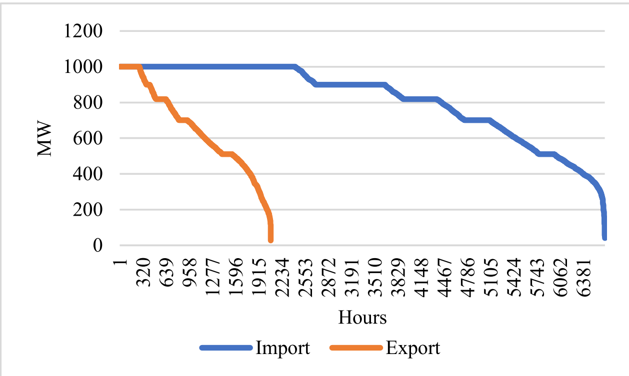

FIGURE 5. Flow duration curve for Sri Lanka [Scenario AvgHyd 17/18(H)] for import and export.

availability in southern India is at its lowest. Benefits to Sri Lanka improves over the July-August period when both of these resources improve.

Fig. 5 shows the flow duration curves for Sri Lanka which shows import (IND→SRI) will be at the limit for nearly 2,300 hours in a year and the link will in general be heavily loaded for more than 70% of the time. Exports would also hit the transfer capability for approximately 300 hours but the average loading in SRI→IND direction is closer to 500 MW, i.e., half of import.

The significance of short-term benefits, notwithstanding the fact that these are based on historic rather than forward looking prices, provides a high degree of comfort and alignment with views expressed for at least a decade [2]–[9]. Analysis for India-Sri Lanka adds a further impetus in light of the fact that annual benefit estimates reported in [4, p.10] was $186 pa which has now more than doubled to $383 million (Table 2), as planned generation capacity additions in SRI have not eventuated. The findings on market-based benefits attains special significance in view of the amended CBET Guidelines [1]. IEX price driven trade as modeled in this analysis can be put to practice within a relatively short period of time once IEX market and operating rules are aligned with this policy. The allocation of benefits between India and Sri Lanka is also noteworthy because it dispels a prevailing notion that trade will happen unidirectionally to the benefit of one trading partner alone. This observation also holds true

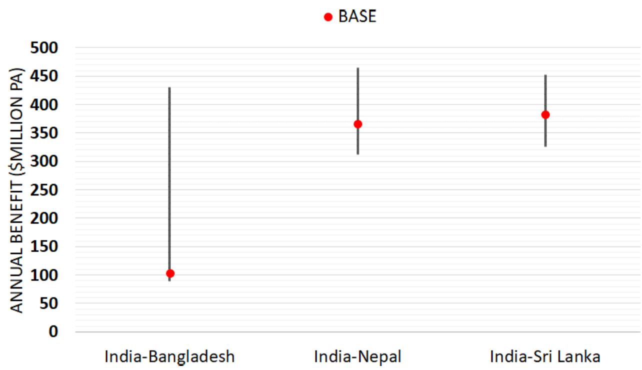

FIGURE 6. Short-term benefits for three main corridors.

for the India-Bangladesh interconnector, the results for which appear a paper prepared by the Bangladesh Power Development Board using EPM [38]. The fact that both parties benefit makes the case for the interconnector even stronger.

Fig. 6 shows the range of short-term benefits for three main corridors. Bhutan is excluded because it has demonstrated trade benefits since 2007 [39]. The ranges of benefits have been created in each case using country-specific scenarios (namely, gas availability in Bangladesh, hydro availability in Nepal and Sri Lanka, together with IEX prices).

Benefits are demonstrably very significant in all three cases. The existing HVDC interconnector in Bangladesh, for instance, with a similar capacity had cost ∼$200 million in 2013. The present analysis suggests if Bangladesh were to have an additional 1 GW capacity available, this will have economic benefits high enough to potentially justify the recovery of such costs in less than 2 years, if not a single year. This is also true for Nepal and Sri Lanka. Bhutan and India have already benefitted from electricity trade tremendously with 11%-21% of Bhutan's GDP coming from export [39].

B. LONG-TERM LEAST-COST PLANNING ANALYSIS

While the benefits of short-term market driven trade present a compelling economic case for the planned interconnectors, these long-lived assets need support from a least-cost planning perspective too. Benefits of trade especially with a large system like India can dissipate if power demand in the importing country is not expected to grow at the prevailing high rate, or if the country already has a plan to build substantial amount of generation capacity.

We have developed a BASE case that collates the demand-supply scenarios from all five countries based on their master plans but does not impose any renewable policy constraint. We have also constructed an alternative policy scenario wherein India meets its 175 GW RE target by 2022 to see if this has any major bearing on the benefits of interconnection. Table-3 presents the findings from the BASE case. Gross benefits in all cases exceed $1 billion in discounted terms (at 10%) effectively for only 10-12 years of the life of the interconnector (as the planned interconnectors are expected to be commissioned over 2023-25). In other words, the projected benefits of the interconnectors are also very significant in

TABLE 3. Long-term benefits of trading: BASE case.

Trading Partner	Benefit ($m)*	Dominant flow (TWh pa)	Major source of benefit
Bangladesh	1,313	Imports 16.7 TWh pa	Opex reduction by $1.7b; $0.75b fixed cost reduced
Sri Lanka	1,571	Imports 7.5 TWh pa from 2025	Opex reduction by 1.6b; $1b fixed cost reduced
Nepal	1,161	Import 5 TWh pa till 2022; Export 20+ TWh pa post 2030	Load shed reduced $0.96b; $0.5b & $0.6 b opex & capex in India
Bhutan	1,253	Exports 35 TWh pa from 2025	Indian opex reduced by $1.46b and capex by $1.2b

* Discounted benefits at 10% in 2019

BASE, after taking into account the planned generation entry and projected demand. Since the cost of these interconnectors are well below the $1 billion mark – this should translate into an attractive payback period for these assets well within the first 10 years of its operation i.e., a fraction of the life of these assets.

Dominant flow directions for Bangladesh and Sri Lanka remain, import from India. Growth in demand and interconnection capacity mean the volume of import would increase considerably relative to the findings of the short-term analysis. For instance, Sri Lanka is projected to import 7.5 TWh over the same 1 GW link instead of 5-6 TWh noted in Table-2. In the long term, an interconnector obviates part of the more expensive generation capacity in Sri Lanka including 1,100 MW of coal that is in the current national plan. As demand increases over the years, the need for import for Sri Lanka also increases. The composition and genesis of benefits also remain quite similar with the importing countries primarily saving fuel costs, but there is also a significant component of avoided capex, namely $0.75 billion in Bangladesh and $1 billion for Sri Lanka (associated with coal plants in both cases). There are also increases in costs for the exporting country that explains the net benefits reported. For example, benefits for Sri Lanka are derived from:

- $1,683 million in opex reduction and $1,006 million capex reduction in Sri Lanka; and
- $1,063 million in opex and $55 million capex *increase* in India; and hence, the net benefit is $1,571 million.

Benefits for India-Nepal also includes reduction in unserved energy (valued conservatively at $300/MWh) as Nepal's demand for 2018-2025 requires significant import averaging 5 TWh pa. As Nepal develops its own hydro resources, flow direction reverses (Fig 7) with 25 TWh of export to India by 2035. Exports in later years reduces opex and capex in India.

If Nepal develops an extra 5 GW of hydro capacity the benefit of India-Nepal interconnection would nearly double to reach $1.9b. The opex reduction on the Indian side will rise to $3.4b which will more than offset the additional capex

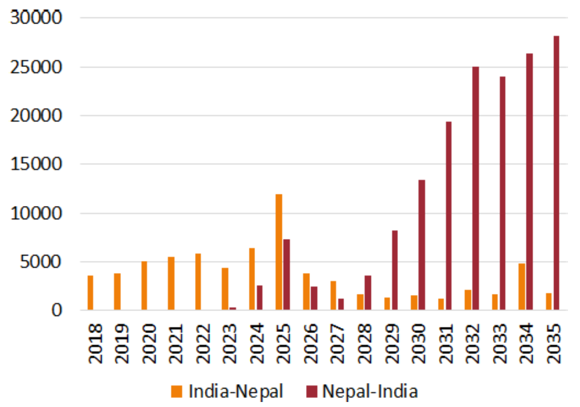

FIGURE 7. India-Nepal transfer (GWh): BASE.

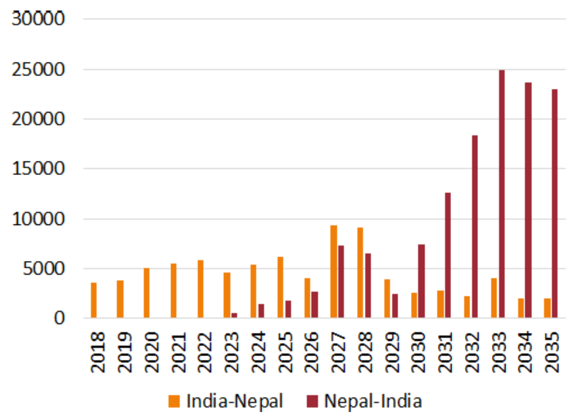

FIGURE 8. India-Nepal transfer (GWh): RE policy.

TABLE 4. Composition of benefits ($m): BASE vs RE policy.

	Avoided Capex	Avoided Opex	Avoided USE	TOTAL
BASE				
India	659	448	0	1106
Nepal	-905	0	959	+54
TOTAL	-247	448	959	1161
RE POLICY				
India	700	-154	0	546
Nepal	-401	0	959	558
TOTAL	299	-154	959	1104

in Nepal. On the other hand, there is a potential risk that India developing 175 GW of RE would reduce its requirement for import. As Fig 8 shows Nepal→ India transfers in the outer years drop off relative to BASE (Fig 7). As a result, the composition of benefits changes markedly (Table 4), but the overall benefits do not decline significantly.

In fact, we do not find the RE POLICY (175 GW target modeled) to diminish benefits significantly in any of the cases. If anything, for a thermal system like Bangladesh, excess RE in India helps to lower the opex in Bangladesh increasing benefits for this case slightly.

Fig. 9 summarizes the findings of all four cases including the additional sensitivity for Nepal that demonstrates

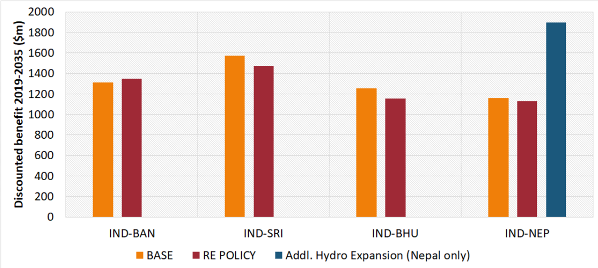

FIGURE 9. Summary of long-term benefits: BASE and RE policy.

the potential significant upside to develop additional hydro (which remains well within the long-term economic potential for the country).

IV. CONCLUDING REMARKS

Regional electricity cooperation and market development in the Bangladesh, Bhutan, India, Nepal and Sri Lanka (BBINS) region have gained significant momentum over the last decade. There is over 3 GW interconnection capacity already in place, and this may quadruple when the projects under construction and planning are completed over the next few years. The significance of these developments is hard to overemphasize. These interconnectors hold the key to connecting countries like Bangladesh and Sri Lanka that do not have significant primary energy resources, with hydro-rich countries like Nepal and Bhutan. The cost savings potential together with other benefits of interconnection make these projects a priority task in the region. Without CBET, these costs savings would otherwise have to be covered by consumers.

It is also important to understand the economics of these projects and answer a set of questions, namely, whether they are supported by the market prices that have prevailed thus far (in India), who would benefit and by how much, what are the key determinants of benefits, and would other policies such as the 175 GW RE target in India obviate the need for some of these interconnectors. It requires a model that is sophisticated enough to endogenously represent the policies, optimize capacity including storage and operational decisions including spinning reserve. It is also essential to provide access to such a tool to the stakeholders in the region for them to carry out these tasks on an ongoing basis.

The present analysis introduces the Electricity Planning Model (EPM) to find answers to some of these questions. This is an extensive modeling study covering five countries with more than a thousand generators and 34 zones in the integrated system. Modeling innovations in the study include combining market prices and dispatch in a single model and endogenous simulation of RE policy in a planning model. We assessed the economic viability of the planned interconnectors for 2019-2035. The findings include the following:

- The estimates of benefits in general corroborates those obtained in prior studies [4]–[9]. In fact, the short-term benefits in some cases have increased substantially (e.g., doubled for India-Sri Lanka relative to [4]). It is reassuring for the studies to converge on the key findings. It also calls for urgent action as there are clearly significant foregone opportunities if investments are delayed;
- The market price-driven, short-term trade analysis highlights the last point most clearly. If the India-Sri Lanka and additional India-Bangladesh capacity were available, it would already save at minimum $100 million and $326 million pa, respectively;
- Benefits accrue to both systems. Even if the volume of exports from Bangladesh and Sri Lanka (to India) is relatively smaller compared to their imports, benefits associated with such export can be disproportionately high. We find for instance that with Sri Lanka exporting only a quarter of its import yields short-term benefits that render the link to be equally valuable to both countries;
- Long-term benefits of the planned projects add up over $5 billion for only 10-12 years of their life, making it a substantial value proposition. We also find that the 175 GW RE target do not make a large dent on these benefits; and
- EPM marks a significant step to implement the model and provide access to system operators and planners. There remains significant room to build capacity among the planners, utility and system operators to sustain modeling efforts to develop a regional plan.

APPENDIX: EPM MODEL FORMULATION

The detailed formulation of the basic version of the EPM model is provided below. The model is cast as a single mixed integer linear programming model for all years. The model is completely flexible in terms of changing the definition of time steps, zones, technology choices and constraints that need to be specified. Additional details on the model including the GAMS source code, a more detailed documentation of the model equations including discussions are available through the first author's ResearchGate page [31].

A. INDICES/SETS

$k \in K$	Renewable energy profiles (the core formulation in sections B-E assume a single state and this notation is dropped)
$d \in D$	where D is the set of types of days or weeks
$f \in F$	where F is the set of fuels
$g \in G$	where G is the set of generators that can be built or the set of technology-specific types of aggregated generators
$q \in Q$	where Q is the set of seasons or quarters
$t \in T$	where T is the set of time periods considered per day (usually 24 hours)
$y \in Y$	where Y is the set of years considered in the planning model
$z, z2 \in Z$	where Z is the set of zones/regions modeled
$sc \in S$	where S is the set of flags and penalties used to include/exclude certain features of the model

1) SUBSETS CONSIDERED

$EG, NG \in G$	where EG and NG is a partition of set G and the former (EG) contains generators existing at the starting year of the planning horizon and the latter (NG) contains candidate generators
$MD \in D$	where MD is a subset of days the planner expects the minimum load levels to be binding
$PT, OPT \in T$	where PT and OPT is a partition of set T that distincts hours in peak and off-peak hours
$RE \in F$	where RE is a subset of set F considered as renewable according to regulator's criteria
$RG \in G$	where MD is a subset of days the planner expects the minimum load levels to be binding
$map_{g,f}$	includes valid combinations of fuels and generators; subset of the set $G \times F$

B. INPUT PARAMETERS

$Availability_{g,q}$	Availability of unit g to generate power in quarter q
$Annual\_built\_limit_y$	Maximum amount of MW allowed to be built per year
$CapCost_{NG,y}$	Capital cost in USD \$ or other monetary unit per MW
$Carbon\_emission_f$	Equivalent tons of CO_2 emitted per MMBTU of fuel consumed
$Carbon\_tax_y$	Carbon price in USD\$ per equivalent tons of CO_2
$Commission\_year_g$	Earliest commission year for generators
$Cont(t)$	Renewable contingency hours, i.e., hours during which RE resources show extreme variability (sampled from climate model reanalysis data)
CRF_{NG}	Capital Recovery factor
$CSP\_storage$	CSP storage capacity in hours
$Demand_{z,q,d,t,y}$	Hourly load level in MW in hour t, day d, quarter q and year y
DemFactor	Spinning reserve requirement as a fraction of demand
$DRate_y$	Discount rate; real or nominal if cost parameters in real or nominal terms respectively
$Duration_{q,d,t,y}$	Duration of each time slice (block) in hours
$FieldEfficiency_{CSP}$	Efficiency of the CSP solar field
$FixedOM_{g,y}$	Fixed Operation and Maintenance Cost in USD \$ or other monetary unit per MW
$FuelPrice_{f,y,z}$	Fuel price in USD \$/MMBTU
$GenCost_{g,f,y}$	Generation variable cost (fuel and VOM) in USD \$ or other monetary unit per MWh
Gen_zone_g	Contains the zone index of the zone the generator belongs to
$HeatRate_{g,f}$	Heat Rate in BTU/MWh
$Life_{NG}$	Operating life for new generators
$LossFactor_{z,z2,y}$	"Linearized" loss factor in % of active power flowing on transmission line
$MaxCapital$	Maximum amount of annualized capital payments in USD\$ billion over the horizon
$MaxFuelOff_{f,y}$	Maximum amount of fuel f (in BTU) that can be consumed in year y
$MaxNewCap_{NG}$	Maximum capacity to be built over the horizon in MW
$MinCapFac_g$	Minimum capacity factor (to reflect minimum load requirements)
$OverLoadFactor_g$	Overload factor of generator g, as %, of capacity
$PlantCap_{EG}$	Existing capacity at initial year in MW
PRM_z	Planning reserve margin per zone z
$RampDn_g$	Ramp-down capability of generator g, as %, of capacity installed
$RampUp_g$	Ramp-up capability of generator g, as %, of capacity installed
$ResCost_g$	Cost to provide reserves in USD \$ or other monetary unit per MWh
$ResOffer_g$	Maximum amount of fuel f (in BTU) that can be consumed in year y
$RESVoLL$	Violation penalty of planning reserve requirement in \$/other monetary unit per MW
$Retirement\_year_{EG}$	Latest retirement year for existing generators
$ReturnRate_y$	Discount factor at the starting year of stage ending at year y
$RPprofile_{g,RE,q,d,y,t}$	Renewable generation profile in % of installed (rated) capacity
$SolarMultipleCSP$	CSP output to solar field ratio
REFactor	Spinning reserve requirement as a fraction of RE generation
$REstate_{q,d,t,k}$	RE profile for state k
$SResSY_y$	System-level spinning reserve constraint in MW
$SResZo_{z,y}$	Zonal/regional spinning reserve constraint in MW
$StageDuration_y$	Duration of a stage represented by year y in years
$StartYear$	First year of the horizon
$Storage\_capacity_{z,y}$	Capacity of storage unit

$Storage\_efficiency_{z,y}$	Efficiency of storage (per charging cycle)
$Storage\_energy_{z,y}$	Energy capability of storage unit
$Sy\_emission\_cap_y$	Cap on CO_2 emissions within the system at year y in equivalent tons
$Topology_{z,z2}$	Network topology: contains 0 for non-existing lines and 1 or -1 to define the direction of positive flow over the line
$TransLimit_{z,z2,q,y}$	Transmission limits by quarter q and year y – the model includes an option to define transfer limit as an integer variable to optimize selection of new lines
$TurbineEfficiency_{CSP}$	Efficiency of the CSP power block
$VarOM_{g,y}$	Variable Operation and Maintenance Cost in USD \$ or other monetary unit per MWh
$VOLL$	Penalty/Economic loss consider per MWh of unmet demand
$WACC$	Weighted Average Cost of Capital
$WeightYear_y$	Weight on years
$Zo\_emission\_cap_{y,z}$	Cap on CO_2 emissions within zone z and year y in equivalent tons
$zone\_index_z$	Index of zone z, unique number assigned to zone z

C. VARIABLES

1) NON-NEGATIVE DECISION VARIABLES

$build_{g,y}$	Investment in MW - integer
$cap_{g,y}$	Capacity available at year y in MW
$emissions_{z,y}$	Emissions of carbon dioxide in tons
$emissions\_Zo_{z,y}$	Emissions of carbon dioxide in tons per zone z
$fuel_{z,f,y}$	Fuel consumption in MMBTU
$gen_{g,f,q,d,t,y}$	Generator output in MW
$genCSP_{g,z,q,d,t,y}$	Power output of the solar panel in MW
$retire_{g,y}$	Capacity in MW retired - integer
$reserve_{g,q,d,t,y}$	Spinning reserve requirement met in MW
$storage_{z,q,d,t,y}$	Level of energy in MWh stored at zone z
$storage\_inj_{z,q,d,t,y}$	Power level in MW at which the storage unit g is charged during hour (q, d, t)
$storage\_out_{z,q,d,t,y}$	Power level in MW at which the storage unit g is discharged during hour (q, d, t)
$storageCSP_{g,z,q,d,t,y}$	Level of energy in MWh stored in CSP unit at zone z
$storageCSPinj_{g,z,q,d,t,y}$	Power level in MW at which the CSP storage unit is charged during hour (q, d, t)
$storageCSPout_{g,z,q,d,t,y}$	Power level in MW at which the CSP storage unit is discharged during hour (q, d, t)
$trans_{z,z2,q,d,t,y}$	Active power in MW flowing from z to $z2$
$unmetDem_{z,q,d,t,y}$	Unmet demand in MW (or equivalently violation of the load balance constraint)
$unmetRes_{z,y}$	Violation of the planning reserve constraint in MW
$unmetSResZo_{z,q,d,t,y}$	Violation of the zonal/regional spinning reserve constraint in MW
$unmetSResSY_{q,d,t,y}$	Violation of the system-level spinning reserve constraint in MW

2) VARIABLES FOR MODELING OBJECTIVE FUNCTION

$carboncost_{z,y}$	Carbon tax payments by generators
$fixedcost_{z,y}$	Fixed Operation and Maintenance Cost along with capital payments in constant prices
$npvcost$	Net present value of power system cost over the whole planning horizon; objective function that optimization model tries to minimize
$reservecost_{z,y}$	Cost to procure spinning reserves
$totalcost_{z,y}$	Annual system cost in constant prices
$usecost_{z,y}$	Damage/economic loss in constant prices because of unmet demand
$usrcost_{z,y}$	Penalty in constant prices for unmet spinning reserve requirements
$variablecost_{z,y}$	Variable cost including fuel and variable operation and maintenance cost in constant prices

D. OBJECTIVE FUNCTION

EPM minimizes discounted system cost over the entire planning horizon as described below.

1) OBJECTIVE FUNCTION AND ITS COMPONENTS

$$npvcost = \sum_{z,y} ReturnRate_y * WeightYear_y * totalcost_{z,y} \tag{1}$$

$$\begin{aligned} totalcost_{z,y} = & fixedcost_{z,y} + variablecost_{z,y} \\ & + reservecost_{z,y} + usecost_{z,y} \\ & + usrcost_{z,y} + carboncost_{z,y} \end{aligned} \tag{1a}$$

$$\begin{aligned} fixedcost_{z,y} = & \sum_{g \in NG} CRF_{NG} * CapCost_{NG,y} * cap_{g,y} * \\ & + \sum_{g} FixedOM_{g,y} * cap_{g,y} \end{aligned} \tag{2}$$

$$\begin{aligned} variablecost_{z,y} = & \sum_{g \in Z,f,q,d,t} GenCost_{g,f,y} \\ & * Duration_{q,d,t,y} * gen_{g,f,q,d,t,y} \end{aligned} \tag{3}$$

$$reservecost_{z,y} = \sum_{g \in Z,q,d,t} ResCost_g * Duration_{q,d,t,y} * reserve_{g,q,d,t,y} \quad (4)$$

$$usecost_{z,y} = \sum_{q,d,t} VOLL * Duration_{q,d,t,y} * unmetDem_{z,q,d,t,y}) \quad (5)$$

$$usrcost_{z,y} = \sum_{q,d,t} RESVoLL * unmetRes_{z,y} + \sum_{z,q,d,t,y} Duration_{q,d,t,y} * SRESVoLL * unmetSResZo_{z,q,d,t,y} + \sum_{q,d,t} Duration_{q,d,t,y} * SRESVoLL * unmetSResSY_{q,d,t,y} \quad (6)$$

$$carboncost_{z,y} = \sum_{g \in Z,f,q,d,t} Duration_{q,d,t,y} * carbon_{tax_y} * HeatRate_{g,f} * carbon_{emissionf} * gen_{g,f,q,d,t,y} \quad (7)$$

E. CONSTRAINTS

1) DEMAND-SUPPLY BALANCE AND TRANSMISSION NETWORK CONSTRAINTS

$$\sum_{g \in Z,f} gen_{g,f,q,d,t,y} - \sum_{z2} trans_{z,z2,q,d,t,y} + \sum_{z2} \left(1 - LossFactor_{z,z2,y}\right) * trans_{z2,z,q,d,t,y} + storage_{out\,z,q,d,t,y} - storage_{inj\,z,q,d,t,y} + unmetDem_{z,q,d,t,y} = Demand_{z,q,d,t,y} \quad (8)$$

$$trans_{z,z2,q,d,t,y} \leq TransLimit_{z,z2,q,y} \quad (9)$$

2) SYSTEM SECURITY/RESERVE REQUIREMENTS

$$\sum_{g} reserve_{g,q,d,t,y} + unmetSResSY_{q,d,t,y} \geq SResSY_y \quad (10)$$

$$\sum_{g \in Z} reserve_{g,q,d,t,y} + unmetSResZo_{z,q,d,t,y} + \sum_{z2} \left(TransLimit_{z2,z,q,y} - trans_{z2,z,q,d,t,y}\right) \geq SResZo_{z,y} \quad \forall z,q,d,t,y \quad (11)$$

$$\sum_{g \in Z} cap_{g,y} + unmetRes_{z,y} + \sum_{z2} \sum_{q} TransLimit_{z2,z,q,y} \geq (1 + PRM_z) * \max_{q,d,t} Demand_{z,q,d,t,y} \quad \forall z,y \quad (12)$$

3) GENERATION CONSTRAINTS

$$\sum_{f} gen_{g,f,q,d,t,y} + reserve_{g,q,d,t,y} \leq \left(1 + OverLoadFactor_g\right) * cap_{g,y} \quad (13)$$

$$reserve_{g,q,d,t,y} \leq cap_{g,y} * ResOffer_g \quad (14)$$

$$\sum_{f} gen_{g,f,q,d,t-1,y} - \sum_{f} gen_{g,f,q,d,t,y} \leq cap_{g,y} * RampDn_g \quad \forall t > 1 \quad (15)$$

$$\sum_{f} gen_{g,f,q,d,t,y} - \sum_{f} gen_{g,f,q,d,t-1,y} \leq cap_{g,y} * RampUp_g \quad \forall t > 1 \quad (16)$$

$$\sum_{f} gen_{g,f,q,d,t,y} \geq MinCapFac_g * cap_{g,y} \quad \forall d \in M \quad (17)$$

$$\sum_{f,d,t} Duration_{q,d,t,y} * gen_{g,f,q,d,t,y} \leq Availability_{g,q} * \sum_{d,t} Duration_{q,d,t,y} * cap_{g,y} \quad (18)$$

4) RENEWABLE GENERATION

$$gen_{g,f,q,d,t,y} \leq RPprofile_{g,RE,q,d,y,t} * cap_{g,y} \quad \forall RE \notin CSP \quad (19)$$

a: CONCENTRATED SOLAR POWER (CSP) GENERATION

$$storageCSP_{g,z,q,d,t,y} \leq cap_{g,y} * CSP\_storage \quad \forall map(g, CSP) \quad (20)$$

$$genCSP_{g,z,q,d,t,y} = RPprofile_{z,RE \in CSP,q,d,t} * cap_{g,y} * \frac{SolarMultipleCSP}{TurbineEfficiency_{CSP} * FieldEfficiency_{CSP}} \quad (21)$$

$$\sum_{f \in CSP} gen_{g,f,q,d,t,y} \leq cap_{g,y} \quad (22)$$

$$\sum_{f \in CSP} genCSP_{g,z,q,d,t,y} * FieldEfficiency_{CSP} - storageCSPinj_{g,z,q,d,t,y} + storageCSPout_{g,z,q,d,t,y} = \frac{gen_{g,f,q,d,t,y}}{TurbineEfficiency_{CSP}} \quad \forall g,z,q,d,t,y \quad (23)$$

$$storageCSP_{g,z,q,d,t,y} = storageCSP_{g,z,q,d,t-1,y} + storageCSPinj_{g,z,q,d,t,y} - storageCSPout_{g,z,q,d,t,y} \quad (24)$$

5) CAPACITY BALANCE TO ACCOUNT FOR NEW ADDITION AND RETIREMENTS

$$cap_{g \in EG,y} = cap_{EG,y-1} + build_{EG,y} - retire_{EG,y} \quad \forall ord\,(y) > 1 \quad (25)$$

$$cap_{g \in NG,y} = cap_{NG,y-1} + build_{NG,y} \quad \forall\ ord\,(y) > 1 \quad (26)$$

$$cap_{g \in NG,y} = PlantCap_{EG} ord\,(y) = 1 \quad (27)$$

$$cap_{g,y} = 0 \quad \forall\,(y,g) : (ord\,(y) - 1) * StageDuration_y + StartYear < Commission\_year_g \quad (28)$$

$$cap_{g,y} = 0 \ \ \forall (y, g \in EG) : (ord\,(y) - 1) * StageDuration_y + StartYear > Retirement\_year_{EG} \quad (29)$$

6) STORAGE CONSTRAINTS

$$storage_{z,q,d=1,t=1,y} = 0 \tag{30}$$

$$\begin{aligned} storage_{z,q,d,t>1,y} = {} & storage_{z,q,d,t-1,y} \\ & + Storage\_efficiency_{z,y} \\ & * storageinj_{z,q,d,t-1,y} \\ & - storageout_{z,q,d,t-1,y} \end{aligned} \tag{31}$$

$$\begin{aligned} storage_{z,q,d,t=1,y} = {} & storage_{z,q,d-1,t=241,y} \\ & + Storage\_efficiency_{z,y} \\ & * storageinj_{z,q,d-1,t=24,y} \\ & - storageout_{z,q,d-1,t=24,y} \end{aligned} \tag{32}$$

$$\begin{aligned} \sum_{t \in PT} storageout_{z,q,d,t,y} \le {} & Storage_{efficiency_{z,y}} \\ & * \sum_{t \in OPT} storage\_inj_{z,q,d,t,y} \end{aligned} \tag{33}$$

$$storageinj_{z,q,d,t,y} \le Storage\_capacity_{z,y} \tag{34}$$

$$storageout_{z,q,d,t,y} \le Storage\_capacity_{z,y} \tag{35}$$

$$storage_{z,q,d,t,y} \le Storageenergy_{z,y} \tag{36}$$

$$storageout_{z,q,d,t,y} \le storage_{z,q,d,t,y} \tag{37}$$

$$storageinj_{z,q,d,t,y} \le Storageenergy_{z,y} - storage_{z,q,d,t,y} \tag{38}$$

7) INVESTMENT CONSTRAINTS

$$\sum_{y} build_{g \in NG,y} \le MaxNewCap_{NG} \tag{39}$$

$$build_{g \in NG,y} \le Annualbuiltlimit_{y} * WeightYear_{y} \tag{40}$$

$$fuel_{z,f,y} \le MaxFuelOff_{f,y} \tag{41}$$

$$\begin{aligned} fuel_{z,f,y} = {} & \sum_{g \in Z,q,d,t} Duration_{q,d,t,y} \\ & * HeatRate_{g,f} * gen_{g,f,q,d,t,y} \end{aligned} \tag{42}$$

$$\begin{aligned} & \sum_{y,g \in NG} ReturnRate_{y} * pweight_{y} \\ & \quad * CRF_{NG} * CapCost_{NG,y} * cap_{g,y} \le MaxCapital \end{aligned} \tag{43}$$

8) ENVIRONMENTAL POLICY

$$\begin{aligned} emissions\_Zo_{z,y} = {} & \sum_{g \in Z,q,d,t} gen_{g,f,q,d,t,y} * HeatRate_{g,f} \\ & * carbon_{emissionf} * Duration_{q,d,t,y} \end{aligned} \tag{44}$$

$$emissions\_Zo_{z,y} \le Zo\_emission\_cap_{y,z} \tag{45}$$

$$\begin{aligned} emissions_{z,y} = {} & \sum_{g,q,d,t} gen_{g,f,q,d,t,y} * HeatRate_{g,f} \\ & * carbon_{emissionf} * Duration_{q,d,t,y} \end{aligned} \tag{46}$$

$$\sum_{z} emissions_{z,y} \le Sy\_emission\_cap_{y} \tag{47}$$

F. RENEWABLE CONTINGENCY CONSTRAINTS

Uncertainties around renewable energy availability on an hourly basis is captured using the stochastic multi-stage version of the model wherein k represents the multiple states of the solar/wind availability that is typically sampled from historic reanalysis data. Key constraints of the expanded model are states in this section. Please refer to [33], [34] for a complete exposition of the stochastic formulation.

1) MULTI-STATE SUPPLY-DEMAND BALANCE

$$\begin{aligned} & \sum_{g \in Z,f} gen_{g,f,q,d,t,y,k} - \sum_{z2} trans_{z,z2,q,d,t,y,k} \\ & \quad + \sum_{z2} \left(1 - LossFactor_{z,z2,y}\right) * trans_{z2,z,q,d,t,y,k} \\ & \quad + storage_{out\,z,q,d,t,y,k} - storage_{inj_{z,q,d,t,y,k}} \\ & \quad + unmetDem_{z,q,d,t,y,k} = Demand_{z,q,d,t,y} \end{aligned} \tag{48}$$

2) RENEWABLE CONTINGENCY CONSTRAINT

$$gen_{RE,q,d,cont,y,k} \le Cap_{RE,y} * minvalue(REstate_{q,d,,cont,k}) \tag{49}$$

3) REVISED SPINNING RESERVE CONSTRAINT

$$\begin{aligned} & \sum_{g} reserve_{g,q,d,t,y,k} + UnmetResSY_{q,d,t,y,k} \\ & \quad = REFactor * gen_{q,d,t,y,k} + DemFactor * sResSY_{y} \end{aligned} \tag{50}$$

Finally, if battery spinning reserves option, battery spinning and spinning reserves, together must cover *REFactor* of RE generation and *DemFactor* of demand.

4) REVISED SPINNING RESERVE CONSTRAINT WITH BATTERY

$$\begin{aligned} & \sum_{g} reserve_{g,q,d,t,y,k} + \sum_{z} Storage_{z,q,d,t,y,k} \\ & \quad + \sum_{z} StorageInj_{z,q,d,t,y,k} - \sum_{z} StorageOut_{z,q,d,t,y,k} \\ & \quad + UnmetResSY_{q,d,t,y,k} = REFactor * gen_{q,d,t,y,k} \\ & \quad + DemFactor * sResSY_{y} \end{aligned} \tag{51}$$

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