Deep Renewables Penetration and Tariff Shocks

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Using a simple scenario analysis based on the latest data on the finances of the distribution utilities and the 20th Electric Power Survey of India, we calculate the possible tariff impact of the addition of around 420 GW of variable renewable energy from 2020–21 to 2031–32. The cost of evacuation of renewable power and battery costs emerges as major factors. We recommend higher union government expenditure to incentivise the creation of transmission infrastructure to facilitate renewables absorption by utilities and the reduction of grid integration and battery deployment costs.

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Constituents of variable renewable energy (VRE) along with wind and solar energy capacity worldwide more than doubled between 2014 and 2019, from 365 gigawatts (GW) to 824 GW. According to the International Renewable Energy Agency (IRENA 2020), this growth was led by China (193%), the United States (US) (88%), India (177%), and Japan (170%), and was largely driven by subsidies in the form of feed-in-tariffs (FIT) and quotas, also known as renewables purchase obligations (RPO).

Political feasibility and social acceptability of the coal phase-out appear to be the main drivers of renewable penetration, scoring more than technical factors (Heinrichs et al 2017). However, higher VRE shares have raised concerns regarding the costs of integrating renewables into the grid and the impact on tariffs and regional equity. The ability of an economy to "carry" a maximum level of VRE commitments has also been highlighted (Cochran 2015). Thus, in Europe, the costs of grid integration could be quite high, around 25% of the VRE investment costs (Schaber and Steinke 2012). For instance, in Spain, the costs of renewables at €22 billion exceeded the benefits of €12.5–€19.7 billion in 2013 (Kreuz and Musgens 2018). In the Netherlands, renewables expansion had a tariff impact of 17% (+/-15%) on retail electricity prices (Brouwer 2015). In Germany, over 2000–13, German consumers would have paid €336 billion at 2011 prices for renewable electricity with a market value of €136 billion (Winter and Schelesewsky 2019), even as German residential tariffs rose by 300% over the same period (Morey and Kirsch 2014). The southern region was favoured over the east, and the burden on the lowest income quintile was more than three times that of the highest. Thus, during 2000–17 in Germany, FIT caused per-household payments to rise from €81 to €261 and the total FIT burden increased from €2.8 billion to €9.2 billion. Similarly, under the FIT regime in Japan, low-income groups have had to pay thrice as much as the higher-income groups (Nagata 2018).

On the other hand, in China, VRE expansion has led to deep curtailments in VRE generation, with a reduction of 17% for wind and 10% for solar in 2016. This is due to a number of factors such as transmission congestion, existing contracts, and the geographical distance between VRE generation facilities and consumption centres. In 2015, the estimated annual grid integration costs in China were of the order of $4 billion (Lin and Li 2015). VRE penetration in the US has been largely driven by renewables portfolio standards (RPS). In 2015, RPS obligations added around 5%–10% to retail energy costs (Barbose 2015). Subsequent estimates put the retail tariff impact of RPS between 10.9% and 11.4% (Upton and Snyder 2017). A study

(Nath and Greenstone 2019), covering 29 US states, shows that RPS led to a price rise of 17% over 12 years due to intermittency, transmission costs, and stranded assets not reflected in the levelised cost of energy (LCOE).

While data on VRE expansion is available for a wide variety of countries, not much has been done to examine the effects of deep VRE penetration on tariffs in developing countries like India, which are characterised by regulated electricity systems, cross-subsidies, financially stressed utilities, and lower market development. This is the research gap that we seek to address in this paper.

Indian Context and Research Questions

The electricity market in India has grown, but continues to be relatively small, and is strongly regulated. The union and states each have their own systems, policies, power trading arrangements, and regulators to set tariffs for all segments of the sector—generation, transmission, and distribution—on the basis of admitted costs. Unlike generation and transmission, the states are in complete control of electricity distribution.

In reforms, post the Electricity Act 2003, the generation component has been delicensed and further opened to private sector investment, along with interstate transmission. However, distribution reforms have been slower. Revenue from power sales does not cover the cost of supply, and distribution companies have historically run heavy deficits. Despite established regulatory systems, tariff rationalisation, reduction of cross-subsidy, and the separation of the supply and wires, businesses have not made commensurate progress. Electricity tariffs are politically sensitive, and many states provide free power to farmers and strongly subsidise the politically dominant middle classes through large subventions to distribution companies. Additionally, significant extents of cross-subsidy are built into the tariff structure. Taken across all distribution companies, agriculture tariffs are around 15% of the average tariff, while the domestic segment is just above 85%. Tariffs for the industry and commercial segments are respectively 150% and 180% of the average (PFC 2019).

Distribution companies procure power from generating companies under long- and medium-term power purchase agreements (PPAs). Fixed costs are recovered separately irrespective of power drawl. Averaging nearly 75% of total costs, power procurement is the single biggest item of expenditure for distribution companies. Similar contracts exist with the transmission utilities responsible for interstate and intrastate transmissions. Here too, fixed charges are payable irrespective of power flows. Capital expenditures for system augmentation, deemed admissible by the regulators, are "pass-through" items. Charges for grid management are separately paid by distribution companies. It is understood that the costs of integrating a higher share of renewables will be eventually passed to the distribution companies and will have to be paid for either through higher tariffs or higher subsidies from the state governments.

After the delicensing and opening up, the past decade has seen an unprecedented expansion of generation capacity. Close to 100 GW of conventional capacity was added during 2012–17, exceeding the national target and outpacing the capacity added in any of the previous five-year plans. Of this, 84% has been coal-based and 35% use supercritical and ultra-supercritical technology. In a trend reversal, private sector plants predominate with 56% of the capacity.

Instead of energy and peaking shortages, there are indications of surplus power. Going forward, the latest official electricity demand projections are provided in the legally mandated National Electricity Plan (NEP) (CEA 2017). These estimates had been deemed optimistic by a wide range of stakeholders even before the lockdown. They flagged the risk of stranded generation assets given the ongoing and planned capacity addition programmes as well as the implications of the backing down of thermal plants and the recovery of fixed costs. Independent studies have also tended to moderate the official projections for electricity demand and capacity addition (Spencer and Awasthy 2019). Despite the impressive capacity addition, India's annual per capita electricity consumption is only about a third of the global average of 3,200 kilowatt-hour (kWh). Unlike the other major countries in the VRE arena, the main objective is to enhance, not moderate and better align electricity consumption with growth targets for the national economy (Press Information Bureau 2019).

Post Paris Agreement (2015), India is to demonstrate a reduction of 30%–35% from 2005 levels of the emissions intensity of GDP by 2030 and an increase in the non-fossil share of installed power capacity to 40% by 2030 (MoEFCC 2020). In preparation to meet these commitments, the plan for renewables deployment was sharply scaled up from 20 GW to 175 GW by 2022 (MNRE 2021) and then to 450 GW consisting of 280 GW grid-scale solar and 140 GW grid-scale wind by 2030 (CEA 2020). The immediate target of 175 GW by 2022, which includes 100 GW of solar grid and rooftop, 60 GW of wind, 10 GW of biomass, and 5 GW of small hydropower, has been fully integrated into the NEP. Nearly 100 GW VRE capacity has been added and an evacuation system for 20 GW VRE has been started. To encourage VRE, transmission charges on projects to be commissioned before 2025 have been waived (MoP 2021). VRE is expected to constitute about 20% of the total system demand of 1,566 billion kWh in 2021–22, rise further to 24.4% of 2,047 billion kWh of projected system demand in 2026–27, and eventually reach 30% by 2030 (CEA 2017). Once attained, India's planned VRE target of 175 GW by 2022 and 450 GW by 2030 will take it past all countries except China.

Technical studies (Palchak et al 2017; CEA 2019) have been carried out to examine the accommodating higher VRE shares. While differing on details, methodology, and the final numbers, all the studies concluded that by 2022 the Indian power system would be in a position to absorb an ever increasing share of renewables—up to 175 GW by capacity and 20%–22% in terms of power generation—through VRE sources. This could lead to the displacement of coal-based power ranging between 243 billion kWh (Spencer 2020), and 270 billion kWh (Palchak et al 2017), subject to adequate power evacuation, accurate forecasting and effective enforcement of renewable purchase obligations (RPOs). Similar studies on integrating 420 GW VRE are awaited.

The plant load factor (PLF) of state-level plants would be forced to go down from 57% to 43%. Higher VRE will reduce thermal loads, even to around 25% on certain days of the year. Average thermal loads will decline to less than 40% for a quarter of the year and stay below the technical minimum of 55% nearly 75% of the time. However, sustained low thermal load will require additional capital expenditure for retrofits (Palchak et al 2017; CEA 2019).

As PLFs fall, the fixed costs for each plant are spread over a lower number of units generated, raising the per-unit fixed costs. In terms of the existing PPAs, the generators will continue to receive time-bound payments on account of fixed charges irrespective of the quantum of power drawn. The distribution utilities will be able to source a lower number of units for the same total outlay on power purchases. To ensure the security of supply, they will have to procure additional power. Unless they can offset the enhanced liability on the fixed charges on a lower number of units through replacement power from cheaper alternate sources, they will face an actual, additional cash outgo on account of replacement power. For a complete offset, the weighted replacement cost of VRE power should be equal to or less than the weighted average variable costs of the coal plants.

A number of countries like Brazil, Argentina, Ukraine, Vietnam, Tanzania, Egypt, Peru, and the Philippines share many of the characteristics of the Indian electricity system and its efforts at reform (Foster and Rana 2019). The issues highlighted in the subsequent sections could carry important lessons for rapid, deep VRE penetration in similarly placed countries worldwide.

We seek to address an important gap in the current understanding of barriers to higher VRE penetration in developing countries through three research questions using data from India. First, how and why will higher VRE impact retail tariffs? Second, what will be the possible impact on energy access and equity across consumer groups? And third, how might they affect the continued growth of VRE in India?

Methodology and Data

Based on the discussions above, we are now in a position to identify the main cost factors relevant to VRE expansion in India. These are (i) additional cost liabilities due to power purchases from VRE sources in lieu of power from coal-based stations through existing power purchase agreements; (ii) costs associated with greater costs of thermal flexibility and cycling; (iii) possible retrofit costs of grid integration and the reworking of grid operation systems, such as deviation settlement mechanisms and standby power; (iv) costs of additional transmission infrastructure for VRE evacuation; and (v) possible costs of stranded assets. Taken together, these cost factors will impact the final tariff structure at the distribution end and will decide the extent of political feasibility and social acceptability of different levels of VRE penetration. We will first try to obtain some estimates for each.

One of the important cost drivers is the continued availability of cheaper coal-based power. Despite a cess of ₹400 per tonne, equal to a carbon tax of about $2 per tonne of coal, each unit of VRE is still more expensive than the variable cost of coal power. Using VRE costs from publicly available information from the tariff orders passed by the different state electricity regulatory commissions, the weighted VRE cost comes to ₹3.18 per kWh. This is quite close to the average level of preferential FITs that several regulators have fixed for decentralised solar generation, that is, ₹3.05 per kWh (JSERC 2020). Though recent auctions have led to lower levellised costs of VRE, those projects are yet to come on stream (MNRE 2021). For the time being, it is the relatively high-cost, PPA-based VRE stations that are relevant.

On the other hand, the variable cost of coal ranges between ₹0.84 and ₹2.38 per kWh (CEA 2021) and coal power continues to be cheaper. A series of recent distribution tariff orders by subnational regulators brings this out more clearly.

For Andhra Pradesh (AP) in 2020–21 (APERC 2020), the average variable cost for the entire power procurement portfolio of 68,901 million kWh is ₹3.31. The average cost per unit of VRE is ₹4.58. It is lower for the thermal component, ranging between ₹2.20 and ₹3.66 per kWh. In case the AP distribution companies wish to purchase one extra kWh of VRE power in lieu of coal power, they will have to pay more, between ₹0.92 and ₹2.38 depending upon the coal station being substituted.

According to the tariff order for 2020–21 concerning Uttar Pradesh (UP), the average variable cost for its power procurement plan of 1,09,327 million kWh is ₹4.31 per kWh. Solar power costs ₹4.21 on average, the wind is cheaper at ₹3.44 and the average for VRE is just above ₹4 per kWh. The state's own thermal plants have variable costs in the range of ₹1.83–₹3.44 (UPERC 2020). Here too, each kWh of VRE could lead to an additional burden ranging between ₹0.56 and ₹2.17 per kWh.

In Maharashtra, the average power purchase cost from April 2020 to February 2021 was ₹4.72 per kWh (MEDC 2021). Renewable power cost was ₹4.97 per kWh, while state sector thermal power was cheaper at ₹4.59 per kWh. The minimum additional liability on account of one kWh of VRE in lieu of thermal power would be the difference between ₹4.97 and ₹4.59, that is, ₹0.38.

On an all-India basis, each kWh of VRE power will cost the distribution utilities at the very least, an additional ₹0.80, as a result of the difference between ₹3.18 and ₹2.38. The gap could be as much as ₹2.34 per kWh at the higher end, but we will take the lower figure for our analysis. Over the years, this is likely to fall as solar generation becomes cheaper. We further assume that this element could be gradually reduced to zero by 2030.

Grid integration charges at an all-India level are estimated to be in the range of ₹1.11 per unit of wind or solar power (CEA 2018). These include higher transmission charges on account of low loads on existing lines at certain times, charges on account of higher deviation margins between scheduled and actual generation due to intermittency, and fixed charge liabilities of standby balancing power. Charges for individual VRE-rich states are higher; thus, for every kWh of VRE, charges in Gujarat are ₹1.45 and in Tamil Nadu ₹1.57. As forecasting improves, it might be possible to substantially address the issues arising out of intermittency, but the costs of battery standby will continue to be important. We are accounting for the transmission system augmentation separately. Hence, it would be reasonable to start with grid integration charges at ₹1.11 per kWh and set it to progressively fall to 0.83 per kWh by 2031–32 as capital costs for grid-scale batteries continue to fall from $203 per kWh to about $100 per kWh by 2030 (Deorah 2020).

Thermal flexibility will call for cycling, that is, ramping up and down, which will add costs on account of deterioration in the heat rate and auxiliary consumption, greater wear and tear, and costs of oil support for repeated starts. These costs will rise as loads decline and plants are subjected to more frequent starts and stops, and are higher for larger plants (Palchak et al 2017 and the CEA 2019); the latter projects additional variable costs due to higher heat rates, higher operations and maintenance costs due to loss of effective hours of operation and additional oil support on account of frequent starts, stops and shutdowns. The former provides an aggregate value and estimates that cycling costs would only be about 7% of the total fuel costs. Fuel costs typically constitute between 50% and 70% of power procurement costs in the bigger states; 70.63% in AP (APERC 2020: 337), and 53.4% in UP (UPERC 2020: 382–84). Applying the 7% norm to the fuel component of the total power procurement costs, we get the annual cycling costs.

Transmission adequacy is key to an effective grid integration of higher renewables-based generation. The Green Corridors project to upgrade the intra-state transmission capacity of the VRE-rich states will cost about ₹101 billion for 20 GW, equivalent to $70 per kilowatt (KW) (MNRE 2020). This appears to be an underestimate.

Worldwide transmission infrastructure capex estimates are much higher. For instance, the Lawrence Lab estimates it at $300 per KW (Nath and Greenstone 2019). The evacuation of 18,500 MW of wind power in Texas cost $7 billion in 2013 (Dorsey-Palmateer 2020), which works out to be $379 per KW. Estimates of older US transmission planning studies are higher at $1500 per KW, while the OECD estimate is $150–$600 per KW. Now, $200 per KW is the generally accepted lower limit (Gorman 2019). Given the geographical concentration of VRE resources, $200 per KW would be a conservative base for transmission capex and would yield cost estimates of close to $84 billion for 420 GW grid-based VRE, equivalent to ₹6,720 billion at ₹80 per dollar. We assume that this additional investment is equally spread on an annual basis from 2024 through to 2030 and debt-financed.

The combined debt of all the subnational transmission utilities on 31 March 2019 was $15 billion (₹1,080 billion) (Power Finance Corporation 2019). An additional debt of the abovementioned magnitude could triple the debt load. Inevitably, interest costs will rise and push up transmission tariffs that will finally be passed on to the consumers via the distribution entities. In 2018–19, the subnational transmission utilities together posted revenues of ₹386 billion. Total expenses, including interest (₹80.69 billion) and depreciation (₹96.83 billion), were ₹352.69 billion. If the entire investment for the additional transmission system of ₹6,720 billion is loan-funded at the historical interest rates paid by them and the assets depreciated by 5.28% as specified by the central regulator, the total additional annual cost impact on the transmission utilities could be easily assessed.

Stranded assets are now recognised as a major barrier to enhanced renewable energy (RE) penetration worldwide. It is distinct from the issue of low system demand and low PLFs. An estimated 300 GW of coal capacity commissioned post 2014 is likely to get stranded over the next 15–20 years (Farfan and Brayer 2017). We have two recent estimates for stranded capacity—46 GW (Palchak et al 2017) and 54 GW (Spencer 2019). This is distinct from capacities earmarked for retirement or phase-out due to reasons like inadequate fuel gas disposal. On average, we are faced with a likely stranded capacity of

50 GW involving plants younger than 25 years. Assuming a straight-line depreciation formula, 10% salvage value, 10-year cost recovery programme for 50 GW stranded coal capacity with an average installation cost of ₹60 million per MW will add ₹81 billion each year to the cost.

Every cost driver will add to the cost of power procurement. Cycling costs will add to the payments to existing coal generators, transmission development costs will add to the charges payable to the transmission utilities, and fixed charge payments due to legacy PPAs for coal power will not fall. While creating room for substitute VRE power, the fall in coal power drawls will add costs due to the mechanism explained earlier. Grid integration charges will be payable to the respective system operator or the transmission utility.

We start by using actual costs, revenues, and electricity consumption by consumer category for 2020–21 provided by the PFC (2022) to build a base-case scenario covering power sales and revenues, power purchases and total expenditures, subsidies and deficits for all the distribution utilities taken together. The PFC report also gives us the average revenue realisation by category. We then use data from the latest Electric Power Survey, summarised in Table 1, which is a statutory report prepared under the Electricity Act to project the overall distribution segment demand, including losses, up to 2031–32 (CEA 2023). The same report provides annual projections for electricity consumption by consumer category. The demand in kWh terms in each consumer segment is multiplied by the respective average revenue realisation for that year to get the sales revenue by category, which then adds up to the total sales revenue.

The aggregate demand is met through power purchase, from fossil as well as VRE sources. The latter gradually increases from the current figure of around 13% to touch 30% by 2030. The average cost per kWh of power purchase is assumed to increase at 3% on a year-on-year basis based on historical trends. Table 2 summarises the assumptions regarding the other cost drivers.

To this base-case costs, we successively add the costs arising out of the factors enumerated at the beginning of methodology section to assess the impact of VRE penetration. The difference between revenues and costs yields the aggregate and per kWh deficit. It is then possible that the overall impact on revenue realisation per kWh, which can be disaggregated, will lead to the impact on revenue realisation by consumer category.

Allowing for differences in billing and collection efficiencies, the ARR can be regarded as a reasonable proxy for tariff for the respective consumer category.

The deficit can be covered through higher ARRs, which translate into average tariff increases. It can also be covered through subsidies and grants.

Results and Discussion

With PFC 2020–21 data for the finances of all the distribution utilities taken together as the base and EPS projections up to 2031–32, we estimate the costs, revenues, and deficits by year from 2020–21 to 2031–32. Total energy sales increase from 961 billion kWh to 2,133 billion kWh. Losses decline by 20% over the decade, which moderates power purchase requirements to an extent. VRE rollout increases sharply—rising from 9% of the total purchase (100 billion kWh) in 2020–21 to 30% (742 billion kWh) by 2031–32.

Costs rise from ₹7,652 billion in 2020–21 to ₹23,724 billion in 2031–32 (Table 3, p 44). The power purchase cost component falls from 76% to 67%. The per kWh power procurement cost will further reduce due to the gradual fall in the grid integration charges and the continuous fall in the prices of VRE power. At the end of the decade, power evacuation costs by way of additional transmission infrastructure emerge as the single biggest cost driver, adding more than a rupee per kWh to the consumer tariff, followed by battery support charges.

Though sales revenues rise from ₹4,741 billion to ₹16,543 billion through the decade by nearly 350%, they consistently fail to cover the costs. To start with, in 2020–21, subsidies at ₹1,308 billion constituted about 20% of the total revenues. As the revenue realisation pattern shows, these are paid mainly to the agriculture and the domestic segments. Even with the subsidy, the distribution utilities together ran a deficit of ₹1,145 billion, funded on a need basis through short-term loans and subventions.

If the subsidy is held constant throughout at ₹1,308 billion, as might be required by norms of financial viability of the

Table 1: Sales of Electricity across Categories up to 2032

Category	2020–21 % Sales	2020–21 Sales in Billion kWh (BU)	2021–22 % Sales	2021–22 Sales in Billion kWh (BU)	2022–23 % Sales	2022–23 Sales in Billion kWh (BU)	2023–24 % Sales	2023–24 Sales in Billion kWh (BU)
Domestic	31.57	303.51	30.31	345.05	30.28	378.84	30.42	404.71
Commercial	8.00	76.91	8.72	99.27	8.73	109.22	8.69	115.61
Irrigation	23.89	229.67	20.97	238.72	21.05	263.36	20.99	279.25
Industrial	25.28	243.04	27.55	313.63	27.39	342.68	27.45	365.20
Others	11.26	108.25	12.46	141.85	12.55	157.02	12.45	165.64
Total		961.39		1,138.52		1,251.13		1,330.42

Category	2024–25 % Sales	2024–25 Sales in BU	2025–26 % Sales	2025–26 Sales in BU	2026–27 % Sales	2026–27 Sales in BU	2027–28 % Sales	2027–28 Sales in BU
Domestic	30.47	431.45	30.45	459.54	30.37	488.97	30.35	519.89
Commercial	8.62	122.06	8.54	128.88	8.54	137.50	8.39	143.72
Irrigation	20.6	291.69	20.17	304.40	19.9	320.40	19.52	334.37
Industrial	28.05	397.18	28.69	432.98	29.27	471.26	29.93	512.69
Others	12.26	173.60	12.15	183.36	12.01	193.37	11.81	202.30
Total		1,415.99		1,509.16		1,611.50		1,712.97

Category	2028–29 % Sale	2028–29 Sales in BU	2029–30 % Sales	2029–30 Sales in BU	2030–31 % Sales	2030–31 Sales in BU	2031–32 % Sales	2031–32 Sales in BU
Domestic	30.36	552.81	30.18	588.22	30.69	626.58	31.15	664.55
Commercial	8.36	152.22	8.29	161.58	8.43	172.11	8.56	182.62
Irrigation	19.15	348.69	18.64	363.30	18.52	378.11	18.43	393.18
Industrial	30.52	555.72	31.49	613.75	30.99	632.70	30.51	650.89
Others	11.62	211.58	11.41	222.39	11.37	232.13	11.35	242.14
Total		1,821.04		1,949.23		2,041.64		2,133.38

Table 2: Other Cost Drivers

Per kWh of Gross Input Energy	2016–17	2017–18	2018–19	2019–20	2020–21	CAGR
Average power purchase cost on input basis	4.15	4.2	4.65	4.73	4.69	3%
Employee cost	0.44	0.45	0.48	0.51	0.54	5%
Interest cost	0.38	0.45	0.39	0.42	0.45	4%
Depreciation	0.17	0.18	0.18	0.22	0.24	9%
Other costs	0.24	0.22	0.3	0.26	0.27	3%
Total	5.38	5.50	6.00	6.14	6.19	4%

Source: Power Finance Corporation (various issues).

sector, the unfunded deficit grows by 473% to ₹5,414 billion (Table 4). Covering this deficit will require the ARR across all categories to grow at about 19% on a year-on-year basis between 2020–21 and 2031–32. The impact on the subsidised segments will be much higher to prevent further skewing of the cross-subsidy pattern.

In case we continue the existing tariff subsidies—90% for agriculture and 10% for domestic—the requirement of direct government support falls to ₹2,318 billion and the annual average increase in revenue realisation stays at around 8%.

The conclusions are obvious. The distribution sector by itself will not be able to drive the increased VRE penetration. There will be significant tariff shocks. Additional subsidies will be required to prevent such shocks. Given that transmission charges emerge as a major cost driver, the government will have to think of continuing to absorb a significant proportion of these costs beyond 2025. Battery support is another big cost driver and one can hope for further cost reductions on this account through various incentives provided by the government.

Table 3: Sales and Costs, FY 2020–21 to 2031–32

Particulars	Units	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29	2029–30	2030–31	2031–32
Energy sales	Billion kWh	961.39	1,138	1251	1,330	1,416	1,509	1,610	1,713	1,821	1,949	2,042	2,133
T and D loss	%	16.44	17.60	17.30	16.86	16.44	16.00	15.61	15.24	14.88	14.50	14.13	13.76
Total power purchase	Billion kWh	1,150	1,382	1,513	1,600	1,695	1,797	1,908	2,021	2,139	2,280	2,378	2,474
Conventional power purchase	Billion kWh	1,050	1,250	1,351	1,392	1,440	1,491	1,545	1,597	1,647	1,710	1,736	1,732
VRE purchase	%	9	10	11	13	15	17	19	21	23	25	27	30
VRE purchase	Billion kWh	100	132	162	208	254	305	362	424	492	570	642	742
Additional VRE purchase (from 20–21 level)	Billion kWh		31	62	108	154	205	262	324	392	470	542	642
Cost of power	₹//kWh	4.69	4.83	4.97	5.12	5.27	5.43	5.59	5.76	5.93	6.11	6.29	6.48
Grid integration charges for VRE	₹/kWh		1.11	1.08	1.05	1.02	0.99	0.96	0.93	0.91	0.88	0.86	0.83
Additional VRE costs due to cheap fossil	₹/kWh		0.80	0.48	0.29	0.17	0.10	0.06	0.04	0.02	0.01	0.01	0.00
Cost of power/kWh after additional VRE	₹/kWh	4.69	6.74	6.53	6.46	6.46	6.52	6.61	6.73	6.86	7.00	7.15	7.32
Cost of power purchase	Billion ₹	5,797	6,249	7,117	7,823	8,585	9,435	10,372	11,378	12,454	13,736	14,792	15,916
Other expenses	Billion ₹	1,855	2,178	2,504	2,783	3,098	3,453	3,857	4,299	4,789	5,374	5,904	6,473
Cost loading on account of additional transmission infrastructure	Billion ₹			72.49	142.49	209.99	274.99	337.51	425.75	510.52	591.83	669.67	744.05
Cost loading due to cycling costs	Billion ₹			306	324	345	368	393	418	444	475	497	511
Cost loading due to stranded assets	Billion ₹			80	80	80	80	80	80	80	80	80	80
Total costs	Billion ₹	7,652	8,426	10,079	11,153	12,318	13,611	15,039	16,601	18,278	20,256	21,942	23,724

VRE= variable renewable energy.

Table 4: Sales and Costs with Subsidy, FY 2020–21 to 2031–32

Particulars	Units	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29	2029–30	2030–31	2031–32
Total costs	Billion ₹	7,652	8,426	10,079	11,153	12,318	13,611	15,039	16,601	18,278	20,256	21,942	23,724
Revenue													
Case A: subsidy and other income kept constant													
Revenue from sale of power	Billion ₹	4,741	6,063	6,885	7,579	8,395	9,316	10,349	11,444	12,662	14,146	15,317	16,543
Other income	Billion ₹	458	458	458	458	458	458	458	458	458	458	458	458
Subsidy	Billion ₹	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308
Total revenues	Billion ₹	6,507	7,829	8,651	9,346	10,162	11,083	12,115	13,210	14,428	15,912	17,083	18,309
Deficit	Billion ₹	-1,145	-597	-1428	-1808	-2157	-2529	-2,924	-3,391	-3,850	-4,344	-4,859	-5,414
Deficit/kWh sales	₹/kWh	-1.19	-0.52	-1.14	-1.36	-1.52	-1.68	-1.82	-1.98	-2.11	-2.23	-2.38	-2.54
Additional deficit over 2021–22	Billion ₹			831	1211	1560	1932	2,327	2,794	3,253	3,747	4,262	4,817
Revenue/kWh sold	₹/kWh	6.77	6.88	6.91	7.02	7.18	7.34	7.52	7.71	7.92	8.16	8.37	8.58
Revenue/kWh required to cover additional deficit	Billion ₹			0.66	0.91	1.10	1.28	1.45	1.63	1.79	1.92	2.09	2.26
Revenue realisation rise for full deficit coverage	%			9.6	13.0	15.3	17.4	19.2	21.1	22.5	23.5	24.9	26.3
Case B: Subsidy and other income proportionately increased													
Revenue from sale of power	Billion ₹	4,741	6,063	6,885	7,579	8,395	9,316	10,349	11,444	12,662	14,146	15,317	16,543
Other income	Billion ₹	458	562	639	703	774	854	944	1,038	1,142	1,265	1,371	1,483
Subsidy	Billion ₹	1,308	1,424	1,624	1,784	1,934	2.094	2,285	2,474	2,678	2,897	3,131	3,380
Total revenues	Billion ₹	6,507	8,048	9,148	10,066	11,104	12,265	13,578	14,957	16,482	18,308	19,819	21,405
Deficit	Billion ₹	-1,145	-378	-931	-1,087	-1,215	-1,346	-1,462	-1644	-1,796	-1,949	-2,123	-2,318
Deficit/ kWh sales	₹/kWh	-1.19	-0.33	-0.74	-0.82	-0.86	-0.89	-0.91	-0.96	-0.99	-1.00	-1.04	-1.09
Additional deficit over 2021–22	Billion ₹			553	709	837	969	1,084	1,266	1,418	1,571	1,745	1,940
Revenue/kWh sold	₹/kWh	6.77	7.07	7.31	7.57	7.84	8.13	8.43	8.73	9.05	9.39	9.71	10.03
Revenue/kWh required to cover additional deficit	₹/kWh			0.44	0.53	0.59	0.64	0.67	0.74	0.78	0.81	0.85	0.91
Revenue realisation rise for full deficit coverage	%			6.0	7.0	7.5	7.9	8.0	8.5	8.6	8.6	8.8	9.1

Ongoing efforts at overall reforms in the distribution sector, including proposed legal amendments (PRS Legislative Research 2022) calling for cross-subsidy reduction and a national merit order for power dispatch, may work against the plans for higher VRE deployment. From a policy perspective, it would be better to take a closer look at the impact of higher VRE throughout the entire electricity value chain, particularly at the distribution end, and re-examine the power demand scenario post COVID-19 before going ahead with ambitious programmes of expanding capacity.

Union government expenditure on renewables has to be stepped up. India has come up in the world renewables arena with a remarkably frugal involvement by the union government. Actual spends—budget and off-budget—by the union MNRE and its agencies during 2014–20 were about ₹750 billion (Lok Sabha Secretariat 2018). This is smaller than the subsidy of €9.2 billion—equivalent to approximately ₹800 billion—to the renewables sector in Germany in just one year, in 2017 (Winter and Schelesewky 2019). Unless the distribution utilities are directly incentivised to absorb higher shares of VRE, their poor finances, legacy power purchase agreements, and the states' own post-COVID-19 financial problems will not be able to accommodate the burden and India's deep decarbonisation drive could falter.

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