

A Service of

ZBW

Leibniz-Informationszentrum Wirtschaft Leibniz Information Centre for Economics

Khanna, Tarun

# Working Paper Optimizing agricultural demand for reducing costs of renewable energy integration

*Suggested Citation:* Khanna, Tarun (2021) : Optimizing agricultural demand for reducing costs of renewable energy integration, ZBW - Leibniz Information Centre for Economics, Kiel, Hamburg

This Version is available at: https://hdl.handle.net/10419/233639

#### Standard-Nutzungsbedingungen:

Die Dokumente auf EconStor dürfen zu eigenen wissenschaftlichen Zwecken und zum Privatgebrauch gespeichert und kopiert werden.

Sie dürfen die Dokumente nicht für öffentliche oder kommerzielle Zwecke vervielfältigen, öffentlich ausstellen, öffentlich zugänglich machen, vertreiben oder anderweitig nutzen.

Sofern die Verfasser die Dokumente unter Open-Content-Lizenzen (insbesondere CC-Lizenzen) zur Verfügung gestellt haben sollten, gelten abweichend von diesen Nutzungsbedingungen die in der dort genannten Lizenz gewährten Nutzungsrechte.

#### Terms of use:

Documents in EconStor may be saved and copied for your personal and scholarly purposes.

You are not to copy documents for public or commercial purposes, to exhibit the documents publicly, to make them publicly available on the internet, or to distribute or otherwise use the documents in public.

If the documents have been made available under an Open Content Licence (especially Creative Commons Licences), you may exercise further usage rights as specified in the indicated licence.



# WWW.ECONSTOR.EU

1	Optimizing agricultural demand for reducing costs of renewable energy
2	integration
3	Tarun Khanna
4	Hertie School, Friedrichstr. 180, 14059 Berlin, Germany. khanna@hertie-school.org
5	While demand response is recognized as a useful tool in reducing costs of integrating renewable
6	electricity, the related literature in developing countries has been limited due to lack of data on end use
7	load profiles. Meanwhile, while the water-energy-nexus is well researched, the value of agricultural
8	pumping load as a demand side resource is ignored. This article fills these gaps by using agricultural load
9	data from two distribution utilities in the Indian state of Gujarat and a mixed integer cost optimization
10	model to estimate the reduction in renewable integration costs using agricultural demand response. We
11	estimate that agricultural load management reduces total system costs by 5% in the current system.
12	Going forward, profile costs of integrating 50% VRE are estimated at \$33/MWh <sub>VRE</sub> . Agriculture demand
13	management can reduce these costs by 24%, by reducing renewables curtailment by 4-7% and improving
14	system flexibility. Deploying decentralized solar irrigation pumps instead of large-scale solar power plants
15	enables higher absorption of peak solar generation and reduces costs further. We conclude that in power
16	systems with moderate share of pumping load, agricultural demand response can be a low-cost tool for
17	renewables integration. Where these costs are disproportionately borne by end consumers, it also has
18	significant consumer welfare effects.

# 19 1. Introduction

20 Demand side management, or the electric utility activities designed to influence customer uses of 21 electricity in ways that will produce desired changes in the utility's load shape (Gellings 1985), can play a 22 key role integrating large amounts of intermittent electricity (Pina, Silva, and Ferrão 2012; Szinai et al. 23 2020; Olkkonen et al. 2018; Yang et al. 2014). Within the demand response literature, relatively little 24 research has explored the value of direct load control to large power systems, despite it being widely 25 prevalent and showing great potential for renewable energy integration (Strbac 2008). Demand response 26 analyses have also often been implemented only in small systems and overwhelmingly in OECD countries. 27 A key barrier to understanding the role and potential of demand side measures in developing countries is 28 that many studies do not utilize real-world load control data, limiting their ability to draw conclusions 29 about the impacts of demand side measures. Several studies assume demand response potential as a 30 percentage of peak demand, without accounting for time series of consumption patterns for different 31 end uses (McPherson and Stoll 2020). For example, in a regulated power system like India, direct load 32 control by utilities can allow for flexible load dispatch to be centrally optimized, accounting for output of 33 variable renewables energy from wind and solar plants, inflexible load, and usage of transmission and 34 distribution. It is anticipated that load control can provide the flexibility required to integrate higher 35 shares of renewable energy (S. Kumar and Madlener 2016). But barring estimates provided by McPherson 36 and Stoll (2020) for the city of Bengaluru, no estimates are available especially at the state or national 37 level. This paper addresses this gap by using new, utility scale agricultural load control data from two 38 electricity utilities in India.

39 We use this data to quantify the value of agricultural pumping load in demand side management in the 40 Indian power system, and in doing so add a different perspective to the literature on water-energy-nexus 41 (Bazilian et al. 2011; Opejin et al. 2020) in developing countries. Agricultural consumption is a major 42 source of electricity demand in developing countries. For example, in Bangladesh irrigation season 43 increases the peak electricity demand almost by a quarter, in Iran groundwater pumping constitutes 11% 44 of total electricity consumption (IRENA 2016), and in northern China annual energy consumption for 45 groundwater pumping was 13.67 billion kWh (Chen et al. 2019). In India, electricity demand for irrigation 46 is about 20% of the total load. Electricity supply for agricultural pumping is also heavily subsidized and 47 even free in many states. To limit the subsidies and prevent their misuse, the supply is controlled by the 48 state-owned electricity utilities and is provided only for maximum of 8 hours in a day. This is enabled by a 49 unique system of separate power distribution network for irrigation supply and household supply in rural 50 areas that allows uninterrupted supply to non-agricultural consumers and complete control over 51 agricultural supply. But agricultural pumping load managed through this system is also a valuable demand 52 resource that can be exploited to reduce the cost of integrating high shares of renewables.

53 The increasing cost of integrating the generation from intermittent wind and solar generation is a major 54 challenge facing the Indian power sector (Srikanth 2018). But this challenge is not uniformly distributed. A 55 few renewable resource rich states lead the energy transition. At the national level, the share of variable 56 renewable electricity (VRE) like solar and wind in total generation was 8% in 2018, but in the states of 57 Karnataka, Tamil Nadu, Rajasthan, Andhra Pradesh, Gujarat, and Telangana, VRE generation has already 58 surpassed 15% (IEA 2020). Agricultural pumping also constitutes a large share—between 15 to 40%—of 59 total electricity consumption (Figure 1) in these states. In this paper we focus on the western state of 60 Gujarat, which has total electricity consumption comparable to that of the Netherlands. The share of VRE 61 in Gujarat was 13% in 2019 (CEA 2019) and is expected to increase to 40-50% by 2030 (IEA 2021). At the 62 same time, agricultural consumption represents around 20% of the total demand and has been growing 63 5-7% annually (GERC 2017a). Using a short-term electricity production cost optimization model, we

- 64 quantify the value of agricultural demand response and its potential for renewables integration in the
- 65 state. The potential in other states, with greater share of irrigation load is likely to be even higher.
- Figure 1: Share of agriculture in electricity consumption vs. share of VRE in electricity generation in large Indianstates. Size of the bubble represents total electricity consumption in 2015.



Source: Tariff orders, Central Electricity Authority (CEA)

# 70 2. Data, modeling methods and scenarios

### 71 2.1. Agricultural load

72 Non-availability of data on end use profiles in India is a major constraint while evaluating demand 73 response options. Previous analyses have used representative end use profiles available from study of a 74 handful of electric feeders, and even these are not available in the public domain (McPherson and Stoll 75 2020). This article uses data published publicly by the distribution utilities (PGVCL and UGVCL) in Gujarat<sup>1</sup> 76 to construct the agricultural supply curves. We call them supply curves and not demand curves, as they 77 do not represent the unconstrained electricity demand of agricultural consumers in response to price 78 signals. This is because electricity supply to agriculture in Gujarat, like much of India, is not on demand 79 but rather is limited to a supply of 8 hours a day. In Gujarat, the agricultural consumers of UGVCL and 80 PGVCL are divided into agricultural groups and power is rostered between the different groups 81 throughout the day in a manner that ensures that all consumers get an uninterrupted supply of 8 hours a 82 day.

<sup>&</sup>lt;sup>1</sup> We are only able to access this data for PGVCL and UGVCL. However, these two utilities together constitute 90% of the total agricultural demand in Gujarat.



83 Figure 2: Month-wise average hourly supply to agricultural consumers in Gujarat (PGVCL and UGVCL)

85 Figure 3: Average agricultural supply (PGVCL and UGVCL) as a percentage of total Gujarat demand

84

86



Every week the utilities publish the quantum of power to be supplied to each group and the time during
which power will be supplied on their websites (PGVCL 2020; UGVCL 2020). But the utilities do not
archive this information on the website, and it is not available for research either. We electronically
scraped this information from the website of the utilities each week for period of one year from
November 2019 to October 2020 using an automated computer algorithm. An example of the scrapped

92 supply information is shown in the appendix. This enabled us to create the hourly power supply curve for

- 93 each agricultural group over the 24 hours of the day. Summing the power supply across the agricultural
- groups of each utility (64 for PGVCL and 59 for UGVCL) we created the power supply curve for each
- utility, and in turn the agricultural power supply curve for the state (Figure 2).

96 Even though we derived them indirectly, the estimated agricultural supply curves are an accurate

- 97 representation of the actual supply. First, the curves have expected shape: power to agricultural
- consumers as a group is supplied mostly at night when the demand from other consumers is low. Only a
- 99 minimal amount of power is supplied to agricultural consumers during evening peak load hours. This is in
- 100 line with our understanding of the power management practices of the utility. Second, considering
- distribution loss of 19.5% for the PGVCL and 9.7% for UGVCL, our agricultural supply curves imply total
   agricultural sales of around 18,000 GWh compared to approved agricultural sales of 18,700 GWh (GERC
- 2017b; 2017a). The difference of 4.3% is reasonable considering the uncertainty in actual distribution
- 104 losses in the agriculture sector in Gujarat.
- 105 The estimated agricultural supply curves show the sizable scale of demand management by Gujarat
- 106 utilities. Agricultural supply is only 13% of overall demand during peak hours in non-monsoon months but
- 107 increases to 35% during off-peak night hours (Figure 3). The pattern holds in monsoon months, though
- 108 the differences are lower due to lower agricultural demand. Additionally, the peak amount of power
- supply to agricultural consumers is around 4500 MW, against a total connected load of approximately
- 110 11,500 MW. This implies that the utilities supply only about a third of the consumers even during the
- 111 peak supply hours. From a power system management perspective, this has the combined benefit of
- ensuring that agricultural pumping contributes minimally to peak demand, and of supplementing lower
- overnight load allowing conventional plants such as coal-fired generation to maintain a more stable
- 114 operation.

## 115 2.2. Other model inputs

- 116 Our mixed integer production cost model minimizes the operational cost of Gujarat power system. In the
- 117 Indian power sector merit order dispatch of power plants is based on this contracted capacity i.e., Gujarat
- can only dispatch the capacity of power plants (both within the state and outside) that are contracted by
- 119 it. To enable an accurate representation of the power available to the state of Gujarat, our production
- 120 cost model maps all the (in state and out of state) power plants which have a power purchase agreement
- 121 with Gujarat and considers only the capacity contracted by Gujarat.
- We used hourly load for the state of Gujarat for 2018-19 (Energy Analytics Lab 2020) for modeling the
- aggregate demand in the model. The load was disaggregated to different discoms using historical power
- requirement data from GERC tariff orders. Agricultural load was deducted from the overall load to
- 125 calculate the inflexible load in the system.
- 126 The actual conventional power plants and the quantum of capacity for each is considered as per the
- 127 Gujarat Electricity Regulatory Commission's (GERC) tariff orders (GERC 2017a). We also take the fixed cost
- 128 (including investment cost, O&M, and depreciation) and variable cost (fuel cost) of operation taken as per
- that approved by GERC. Operational parameters for the thermal power plants are based on generic data
- 130 from Central Electricity Authority. Deterioration in parameters due to lower capacity factors is not
- considered. For renewable energy, we consider the actual installed capacity for the base scenario and
   assume higher capacity for various scenarios (see scenarios). The generation profile of RE power plants is
- based on data collected average hourly generation profiles by month for 2018-19 published by Gujarat
- 134 SLDC (Gujarat SLDC 2019).

#### 135 2.3. Production cost model in PLEXOS®

136 This paper used a production cost model built for the state of Gujarat in PLEXOS<sup>®</sup> Integrated Energy

- 137 Model, an industry standard commercial energy market modelling tool provided under an academic
- license by Energy Exemplar (Energy Exemplar 2021). The PLEXOS<sup>®</sup> engine has four separate phases that
- can be run separately or in combination: long term (LT), projected adequacy of system assessment
- 140 (PASA), medium term (MT) and short term (ST), which performs Unit Commitment and Economic
- Dispatch (UC-ED). Each phase has a separate function and if run in combination, the higher-level phases
- pass results to the lower phases. Each step is optimized as a whole, taking the starting condition from the
- previous step and with no 'awareness' of the coming step. Thus, there is perfect foresight for the intervals
- 144 within the step but no information on future steps.
- 145 The UC-ED problem formulated in the ST phase is a combination of Unit Commitment, where the set of
- 146 generators operating (committed) in any given time interval is determined, and Economic Dispatch,
- 147 where the lowest-cost configuration of power output levels is determined in each period for committed
- generators. This combination of binary (generator on or off) and linear (output of each committed
- generator) decisions is solved using mixed integer-linear programming (MILP). The main optimization
- 150 objective is minimizing operating costs of the power system subject to the condition that hourly demand
- must be equal to supply. Further constraints are imposed to account for generator operational
- 152 characteristics, including minimum and maximum operating levels for each generator, ramp rates etc.
- 153 Other key features of the modelling are hourly economic dispatch over a 1-year period with a 1-day
- planning horizon and an additional 1-day look-ahead at 8-hourly resolution.

#### 155 2.4. Modeling agricultural load optimization

- 156 The modeling approach for agricultural load follows the flexible load representation by Hungerford,
- Bruce, and MacGill (2019). Agricultural load is modelled using the PLEXOS<sup>®</sup> 'purchaser class' that allows a specified quantity of load to be bid into the wholesale market at a particular price. This is mathematically
- 159 equal to,

160 
$$d_t = d_t^I + \sum_{i=1}^J d_{i,t}^F$$
 (1)

- 161 Further constrained by:

163 
$$\sum_{t}^{T_{u}} d_{j,t}^{F} = E_{j,u}^{F}$$
 (3)

- 164 where:
- 165  $d_t$  is the system demand (MW) in each time period
- 166 *j* is the index of flexible demands
- 167 *t* is the index of time periods
- 168 *u* is the index of days

- 169  $T_u$  is the set of time periods in day u
- 170 *J* is the total number of flexible demands
- 171  $d_t^I$  the level of inflexible demand in time period t (MW)
- 172  $d_{i,t}^F$  the level of flexible demand dispatched for end use object j in time period t (MW)
- 173  $P_{j,t}^F$  is the maximum instantaneous level of flexible demand for end use object j in time period t (MW)
- 174  $E_{i,u}^F$  is the required energy of flexible demand for end use object j on day u (MWh)
- 175 In the current supply scenario, the level for flexible demand  $(d_{j,t}^F)$  in each discom is taken equal to the
- actual power supplied to agricultural consumers in that hour as derived in section 2.1 such that equation
- 177 (4) is binding with an equality sign. In the optimized supply scenario, the level of flexible demand  $(d_{j,t}^F)$  in 178 each discom in equation (5) is considered less than or equal to the maximum supply to agriculture in the
- 179 current system (i.e.,  $P_{PGVCL,t}^{F}$  = 2500 MW and  $P_{UGVCL,t}^{F}$  = 2000 MW). Additionally, the daily required
- energy of flexible demand  $(E_{i,u}^F)$  in equation (6) is taken equal to the daily energy supplied currently to
- agricultural consumers on a particular day (a day in PLEXOS<sup>®</sup> is from 00:00 hours to 23:59 hours). Taken together, these constraints allow the model to optimize costs by varying agricultural supply during the day while keeping intact the constraints in peak supply on account of distribution system capacity and seasonal variations in agricultural supply. But to keep the optimization problem tractable given limited computing power, a restriction of 8-hour continuous supply is not applied in the optimized scenario. In
- the solarization scenario, the total energy the maximum instantaneous level of flexible demand  $(P_{j,t}^F)$  is assumed to be equal to 1.5 times the connected load of the agricultural consumers in the discom, which is the maximum solar capacity for which subsidy is given.

## 189 2.5. Modeling scenarios

#### 190 Generation scenarios

- Current generation mix: The model maps all the existing thermal power plants in the state. The current generation mix scenario replicates the generation from this power plants in the year
   2018-19. This also serves as the validation scenario for the model.
- High renewables portfolio: At present renewables account for 13% off overall generation in the 194 state. Since Gujarat does not plan to build any new coal power plants this is expected to rise in 195 196 the future. In our high renewable energy scenarios, we consider the share of renewable energy being 20%, 30% and 50% of the overall generation, in line with the plans laid out by the state 197 198 government for development of renewables (IEA 2021). To account for differences in energy 199 profile depending higher wind or solar development, we modeled three sub-scenarios—High 200 Wind (ratio of solar to wind generation = 1:4), High Solar (ratio of solar to wind generation = 2:1) and Equal Wind-Solar (ratio of solar to wind generation = 1:1). 201

#### 202 Agricultural demand scenarios

Current supply: The supply hours and quantity of power supplied to agricultural consumers is
 taken equal to the curves estimated using the supply data in section 2.1.

- Unconstrained agricultural demand: Since agricultural demand is managed it is difficult to
   understand the true extent of load control exercised by electricity utilities in Gujarat. We try to
   estimate this by creating a hypothetical supply scenario wherein farmers are provided most of
   the power during the daytime hours between 8h-20h. This helps us assess the flexibility provided
   by agricultural load to the current power system.
- Optimized agricultural supply: We optimized agricultural supply to minimize system wide
   generation cost. Optimized supply assumes a) same daily energy supplied for irrigation as per
   current schedule, only timing varies b) the max agricultural load served by a utility at any point is
   equal to the maximum load currently served to account of the distribution system level grid
   constraints. See section 2.4 for detailed mathematical treatment.
- Solarization: To estimate the impact of solarization of agriculture, 50% or 100% of agriculture
   load is shifted to solar pumps. The impact is considered to reflect the gross metering schemes
   that are being proposed for solarization of agricultural pumps.

# 218 3. Results

## 219 3.1. Overview and key trends

The maximum hourly demand in Gujarat in 2018-19 was 18000 MW in September and the min was 220 221 7600 MW in November. This demand was met through a predominantly coal based system which 222 constitutes about 80% of total generation. VRE accounted for 13% of the overall electricity generation in 223 2018-19, with most of the generation from wind—the ratio of solar: wind in RE generation is 1:4. But this 224 is expected to change due to increasing deployment of solar power plants. This paper models the Gujarat 225 power system under various scenarios with the share of renewables varying between 20% and 50% of 226 total generation, including sub-scenarios for higher share of wind, higher share of solar or equal share of 227 wind and solar (Figure 4). At higher renewable shares, the operation of coal power plants changes. The 228 weighted average capacity factor of coal power plants declines from 75% in the current system to 47% in 229 a system with 50% VRE. There are frequent start/stops and increasing/decreasing (ramping) the output 230 of coal power plants that is detrimental to their performance and imposes additional cost. The system is 231 unable to absorb VRE at certain times leading to curtailment. The curtailment is highest during the 232 months of Dec-Feb and May-Jun, when solar generation is high and net load is low. Total curtailment 233 increases sharply as VRE share crises to about 50% and is estimated at 10.1% for solar and 6.9% for wind. 234 It should be noted that this is the scheduled curtailment on account of imbalance between demand and supply. It does not account for curtailment due to forecast errors in RE generation and local grid 235 236 congestion that cause curtailment in the system even with current RE penetration and could persist also 237 in the future.

- 238 Figure 4: Model output showing curtailment of wind and solar electricity under increasing penetration of renewable
- energy and major system parameters. These results are derived for VRE shares of 20%, 30% and 50% considering
- 240 1:1 ratio of solar to wind in VRE generation.



# 3.2. Value of agricultural demand control to Gujarat's electricity system

The current supply schedules are highly optimized for the coal-based generation mix. Figure 5, left panel 243 244 shows the average current supply to agriculture by PGVCL and UGVCL, along with the optimized supply to 245 agriculture chosen by the PLEXOS model assuming the current capacity mix. The two curves overlap 246 neatly, and the differences could be on account of practical limitations in shifting load and providing 8 247 hours of continuous supply. Disaggregating the supply curves by season – monsoon and non-monsoon – 248 reveals similar trends. To quantify the benefit derived by the Gujarat discoms from direct load control of 249 agriculture, we created a hypothetical demand curve for agricultural consumers at the state level wherein 250 most of the power is demand during daytime (8-20h). The current demand management practises reduce 251 total system costs by about 5%, due to lower start and shut down expenses, decreases ramping costs and 252 lower fuel costs. Coal power plants are operated much more efficiently as evident from the reduction unit 253 starts and ramping (Figure 5, right panel). In the Indian power system agricultural load is seen as a liability 254 because of the subsidies that need to be provided in addition to the maintenance of the vast rural supply 255 network. However, this analysis shows that direct load control of agriculture is a valuable system service 256 that is undervalued by system planners. Provision of similar scale of demand response service through the 257 market mechanism, if even possible, would be imply an additional cost to utilities.







#### 261 It is optimal to shift agricultural supply to day to increase the share of solar generation. The current

supply schedules would not need to change much if ratio of solar: wind generation remains at current

levels, except during monsoon months when higher wind generation during the day allows daytime

supply. The current supply schedules will however need to change with higher RE significantly if

significant amount of solar capacity is added to the system.

Figure 6: Actual and optimized supply hours to agriculture under various renewable energy scenarios. The supply curves are derived for models with 50% VRE share.







- 276 management can therefore reduce the imbalances in the power system allow for a more efficient
- 277 operation of the existing thermal power plants, while simultaneously enabling increased absorption of 278 renewable energy in the system
- 278 renewable energy in the system.





An obvious challenge in doing so would be that peak solar generation occurs only for about a couple of

283 hours during the day. The current agricultural supply is organized such that all farmers are guaranteed a

fixed amount of supply for 8 hours. With increasing share of solar, the discoms can switch most

consumers from nighttime to daytime hours but that would not allow the agricultural demand to be

flexible enough to deal with the solar peak. This implies finding alternative ways of dealing with the solar

287 peak or curtailing the peak generation.

#### 288 3.3. Centralized vs. decentralized solar deployment

289 Solar deployment in India has so far been dominated by centralized, utility scale solar power plants. 290 Against a total of 34,197 MW of utility scale solar capacity, only 6792 MW of decentralized solar capacity 291 has been added till date (Bridge to India 2020). The recently launched government of India PM-KUSUM 292 policy marks a major shift. Component-C of the policy incentivizes solarisation of grid connect irrigation 293 pumps at the individual farm level, wherein the government will provide subsidies up to 70% of capital 294 cost (GOI 2019). The scheme can be operationalized in either the net metering or gross-metering mode. 295 Under the net metering scheme, the agriculture pump will continue to run at the rated capacity taking 296 power from solar panels and balance power from grid, if required. Since the pumps will be kept 'ON' 297 during the sunshine hours from morning to evening, there is a possibility that the farmer may run the

pump during the peak hours drawing power from the grid and feeding surplus solar power during the off-

299 peak hours. Under the gross metering scheme, the pump will only be run on the solar power as in case of

- stand-alone solar pump and no power will be drawn from the grid for the operation of pump. The existing
- 301 motor pump set will have to be replaced to run directly on solar power. When solar power is not being
- 302 used for irrigation, it can be fed into the grid.

303 We capture solarization with gross metering in our model by removing the agricultural load from the 304 system and instead increasing the solar power capacity by an amount equal to 1.5 times the connected 305 load that it replaces as per the scheme provisions. Solarization with gross metering seems to be the most 306 system optimal way of achieving high levels of solar energy penetration as it allows load to vary exactly 307 with solar output. Because solar pumps can vary their output with the energy generated from the panels, 308 they can absorb the peak solar generation. As can been seen in Figure 8, solarization can achieve the 309 "ideal" optimal agricultural supply curve under high solar penetration. This results in variation in the 310 quantum of water pumped but as pilots with off-grid pumps have shown that does affect the farmers in

any significant manner (DSUSM 2017).

#### 10000 9000 8000 7000 6000 5000 4000 3000 2000 1000 0 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 1 Current supply Optimized at 50% VRE, decentralized solarization Optimized at 50% VRE, centralized 8 hour supply

#### Figure 8: Agricultural supply hours – centralized vs. decentralized solarization

313

314 Solarization allows for an additional gain system cost optimization that is not possible in state-wide 315 dispatch as the constraint of 8-hour continuous supply and distribution level grid constraints limit the amount of agricultural demand that can be met at any time. Comparing the system cost and performance 316 317 metrics under various shows that the solarization is a more effective means of reducing costs and impact 318 of integrating solar energy. While there are minimal incremental gains in reduction in unit starts for coal 319 and gas power plants, ramping requirement is further reduced. Importantly, solarization allows for 320 greater absorption of renewable energy in the grid. Solar curtailment reduces from 3-10% and wind 321 curtailment reduces from 3-7% in other scenarios to almost nothing.

# 322 3.4. Economic costs of VRE integration

Integrating large shares of RE imposes costs on the power system that can be categorized into—the impact of temporal variability or "profile costs", the impact of uncertainty or "balancing costs", and the impact of location or "grid-related costs" (Ueckerdt et al. 2013; Hirth, Ueckerdt, and Edenhofer 2015). Of these, profile costs have been shown to be the largest component of integration costs (Hirth, Ueckerdt, and Edenhofer 2015). Profile costs reflect the market value of electricity at different moments in time and the opportunity costs of matching VRE generation and load profiles. They can further be decomposed

- 329 into flexibility costs and the utilization effect. Flexibility costs are incurred due to adjusting the output of
- thermal plants through higher ramping, starts and shutdowns. Utilization effect is the cost imposed by
- VRE on system due to their generation profile their unavailability during certain times of the day, which
- leads to lowered utilization of thermal capacity and curtailment of VRE during certain hours of the day
- 333 when the system cannot absorb the excess generation. Previous studies (McPherson and Stoll 2020;
- Hummon et al. 2013) on RE integration in India have focused on capacity credit or adequacy costs.
- However, adequacy costs only address the low-capacity credit of VRE, while the utilization effect is more
- general: thermal utilization is reduced as the residual load curve becomes steeper and VRE utilization is
   reduced as generation needs to be curtailed (Hirth, Ueckerdt, and Edenhofer 2015). Hence, profile costs
- and the utilization effect can be understood as a generalization of adequacy costs.
- Flexibility costs. We estimate flexibility costs for the Gujarat system to be between on an average \$1-
- 2/MWh using standard data for cycling costs (N. Kumar et al. 2012). The marginal increase in costs per
- unit of VRE generation is estimated to around \$2/MWh<sub>VRE</sub> at 50% VRE penetration (Table 1). These
- estimates are in line with those from other power systems (Hirth, Ueckerdt, and Edenhofer 2015). As
- 343 expected, the costs increase with share of VRE in the system, though the marginal increase is relatively
- 344 stable. Optimizing agricultural supply keeps flexibility costs to less than \$1/MWh, with a negligible
- increase in marginal costs. While small, it should be noted that these estimates are for scheduled ramping
- and starts, while uncertainty-related ramping and cycling are reflected in balancing costs. Further, they
- do not consider the impact of frequent cycling on plant heat rates.

	With current agricultural supply				With optimized agricultural supply				
	Current energy mix	20% VRE	30% VRE	50% VRE	Current energy mix	50% VRE			
Flexibility costs									
Generation (TWh)	120	120	120	120	120	120			
VRE generation (MWh)	14,153	22,844	34,003	57,335	14,153	60,709			
Start up/shut down charges (\$'000/a)	95,405	1,09,857	1,32,585	1,75,841	81,266	78,922			
Ramping charges (\$'000/a)	9,131	12,547	16,288	17,735	5,088	10,587			
Flexibility costs (\$/MWh)	0.87	1.01	1.23	1.60	0.72	0.74			
Marginal increase in flexibility costs (\$/MWh <sub>VRE</sub> )		2.06	2.37	1.92		0.07			
Marginal increase in VRE capacity costs (₹/kWh <sub>VRE</sub> )		0.14	0.17	0.13		0.00			
Utilization effect-thermal capacity									
Thermal capacity (GW)	19	19	19	19	19	19			
Thermal generation (GWh)	105,605	97,055	85,970	62,701	105,689	59,351			
Capacity factor (%)	64%	59%	52%	38%	64%	36%			
Thermal capacity costs (\$'000/a)	1,887,785	1,887,785	1,887,785	1,887,785	1,887,785	1,887,785			
Thermal capacity costs (\$/MWh <sub>thermal</sub> )	18	19	22	30	18	32			
VRE generation (MWh)	14,153	22,844	34,003	57,335	14,153	60,709			
Marginal increase in VRE capacity costs due to utilization (\$/MWh vRE)		18	19	22		22			
Marginal increase in VRE capacity costs due to utilization (INR/kWh <sub>VRE</sub> )		1.23	1.35	1.53		1.54			
Utilization effect–VRE utilization									

Table 1 Economic (profile) costs of RE integration under various shares of VRE, and with and without agricultural DR

	With current agricultural supply				With optimized agricultural supply	
	Current energy mix	20% VRE	30% VRE	50% VRE	Current energy mix	50% VRE
VRE potential generation (MWh)	14,153	22,845	34,118	62,541	14,153	62,541
VRE generation (MWh)	14,153	22,844	34,003	57,335	14,153	60,709
VRE curtailment (MWh)	-	2	115	5,206	-	1,832
VRE curtailment (%)		0%	0%	8%		3%
Marginal increase in VRE capacity costs due to curtailment (\$/MWh <sub>VRE</sub> )	-	0	0	9	-	3
Marginal increase in VRE capacity costs due to curtailment (INR/kWh vre)	-	0.00	0.03	0.62	-	0.19

349 **Utilization effect.** The economic value of wind and solar generation is often lower than the average 350 electricity price and it decreases with penetration due to reduced utilization of thermal plants, and 351 curtailment of VRE generation. Gujarat currently has 19 GW of thermal power capacity with a total fixed 352 cost payment of \$ 1888 M/a (INR 13,200 crore/a). As per long-term PPAs between the distribution utility 353 and thermal power plants, this amount is payable irrespective of the actual utilization of the thermal 354 capacity. The average thermal capacity utilization decreases from 64% in the current system to 38% with 355 50% VRE generation. Increasing VRE share from current to 50% increases fixed cost from \$18/MWh<sub>thermal</sub> 356 to \$30/MWh<sub>thermal</sub>. This corresponds to a marginal increase of \$20/MWh<sub>VRE</sub> in thermal capacity costs at 357 50% VRE share. Reduced thermal plant utilization is not only a transitory phenomenon. Not only does a 358 swift introduction of renewables reduces thermal plant utilization, high VRE shares lead to lower average 359 plant utilization even in the long-term equilibrium (Hirth, Ueckerdt, and Edenhofer 2015). Optimizing the 360 agricultural supply does not prevent a decline in capacity utilization of thermal power plants. The second 361 component of utilization costs is due to VRE curtailment. We estimate that VRE curtailment increases sharply as VRE share reaches around 50% and the marginal increase in VRE capacity costs rises sharply to 362 363 \$9/MWhyre. Note that these costs are due scheduled curtailment on account of imbalance between 364 demand and supply. It does not account for curtailment due to forecast errors in RE generation and local 365 grid congestion. Optimizing the agricultural supply allows for utilization of the peak time solar generation 366 and sharply reduces VRE curtailment from 8% to 3% and the marginal increase in utilization costs reduces 367 by more than half to  $\frac{3}{MWh_{VRE}}$ .

368 Sharing of profile costs. Under perfect and complete electricity markets in long-term equilibrium, profile 369 costs estimated above would appear as reduced revenues from the day-ahead spot market, implying 370 reduced average revenue for all power plants in the short term and permanently reduced revenues for 371 VRE plants in the long term (Hirth 2013). However, 90% of the power in India is traded not on the 372 wholesale market but rather through long-term contracts between distribution companies and 373 generators. Legacy contracts for thermal generators are based on a two-part tariff (fixed cost and fuel 374 cost calculated and calculated separately on cost plus basis) and contracts for renewable generators 375 consist of single tariff (calculated either on cost plus basis or increasingly in RE auctions). The contracting 376 structure in India implies that profile costs are shared in a way that little incentive exists to reduce them. 377 Flexibility costs are typically borne by the generation companies in the contracting structure outlined 378 above. Though thermal power plants can ask to be compensated on account of frequent start-stops and 379 ramping, most of these costs must be absorbed as higher operational expenses. The largest component 380 of profile costs—the utilization effect of thermal power plants is borne completely by distribution 381 companies who are required to pay the fixed costs irrespective of the capacity utilization. The second 382 component of profile costs—the utilization effect of VRE plants will also add to power purchase cost of

- 383 utilities. In most Indian states, VRE power plants have a must run status and generators need to be
- compensated by the distribution company for scheduled curtailment. Often curtailment of VRE is claimed
- by utility on grounds of system security and generators are not compensated. To the extent that investors
- in RE power plants can anticipate curtailments and price their bids in renewables auctions accordingly,
- costs are again likely to be borne by the distribution companies. Despite the increased cost, distribution
- 388 companies have little incentive to remedy the situation. Power purchase costs are completely
- recoverable in regulator mandated retail tariffs, increase in integration costs will therefore directly
- translate into in increase in retail prices and reduced consumer welfare.

# 391 4. Conclusions and discussion

- Agricultural pumping load is seen as a liability by electricity utilities in India due to poor paying capacity of farmers and heavy cross-subsidization. Farmers are provided electricity supply only for a few hours a day and that too late in the night when demand from other sources is lacking. This article shifts perspective by looking at the value of agricultural pumping demand as demand side resource. Enabled by the system of segregated power supply for irrigation, pumping load has long been used to flatten the load curve but its
- 397 value to the system service has largely been ignored.
- 398 We collected data on hourly supply to 124 agriculture groups in two distribution utilities in the Indian
- 399 state of Gujarat for one year and integrated the derived agriculture supply curves in a production cost
- 400 optimization power model. We find that agriculture pumping load provides a valuable system service to
- the grid through the direct load control on the agricultural pumps in India. We estimate that in the Indian
- state of Gujarat this leads to a reduction of 5% in total system costs and allows for smoother operation of
- 403 coal power plants by reducing number of starts and ramping requirement. Such demand side
- 404 management will continue to be valuable especially from the point of view of renewables integration.
- Appropriate management of pumping load can help reduce curtailment of renewable energy by 3-6% in s
   system with 50% VRE share.
- 407 Further, optimization of agricultural demand can limit increase in flexibility costs to under \$1/MWh<sub>VRE</sub> and
- 408 reduce marginal increase in profile costs on account of VRE utilization from \$9/MWh<sub>VRE</sub> to \$3/MWh<sub>VRE</sub>.
- 409 Since neither of these costs are directly borne by the distribution companies, they lack incentives to
- 410 optimize demand to enable higher RE deployment. This may partly explain why demand response
- 411 programs of all kinds, including agricultural demand shifting, have been implemented only to a limited
- 412 extent. This is mitigated when the must run status of VRE is enforced, or distribution companies are
- 413 provided other incentives to undertake demand shifting policies.
- 414 A potential limiting factor in the use of agricultural load control may be that such direct load control over
- 415 agricultural pumps may no longer be possible when the recently launched KUSUM scheme, which will
- 416 support farmers to replace existing diesel pumps with solar PV pumps (with both on-grid and off-grid
- 417 features) is implemented. But this paper shows that if correctly implemented a decentralized approach to
- 418 deployment of renewables is superior from a power system cost-optimization perspective.
- There are however limits to solarization of solar pumps on a massive scale. First, solarization with gross
- 420 metering requires an additional expense by farmers to convert their solar pumps to run directly on solar
- power. Second, unchecked use of solar panels (with zero marginal cost electricity) can worsen the
- 422 problem of ground water utilization, which is currently controlled by limiting the supply of electricity.
- 423 Importantly, gross, or net metering schemes that provide time varying feed-in-tariffs would need to be
- 424 used to provide incentive to farmers to feed electricity into the grid at the time when it is beneficial for

- the grid. Well-designed feed in tariffs can also provide additional income to farmers, besides providing
- incentives for conserving water (Shah, Verma, and Durga 2014). If such feed-in-tariffs are priced correctly,
- farmers can be moved from a system of "load control" to "demand response", wherein they are suitably
- reimbursed for the demand response services that they provide to the power system.
- The predominance of agricultural load in the power system is not uniquely Indian, nor is the usefulness of
- agricultural demand response. Agricultural consumption is a major source of demand in emerging and
- 431 developing countries. More research into ways of exploiting this demand side resource would provide
- policymakers and system planners across the developing world an additional, cheap flexibility option to
- 433 facilitate integration of renewables.

# 434 Acknowledgements

- 435 I would like thank Zoe Hungerford and the RISE team at the International Energy Agency, Paris who
- 436 provided the guidance for development of the production cost model. This analysis was made possible
- 437 under the academic license provided by Energy Exemplar for use of energy market modeling software
- 438 PLEXOS<sup>®</sup>, and the academic license for the use of Gurobi<sup>TM</sup> Optimizer.

439

# 440 References

- Bazilian, Morgan, Holger Rogner, Mark Howells, Sebastian Hermann, Douglas Arent, Dolf Gielen, Pasquale
   Steduto, et al. 2011. "Considering the Energy, Water and Food Nexus: Towards an Integrated
- 443 Modelling Approach." *Energy Policy* 39 (12): 7896–7906.
- 444 https://doi.org/10.1016/j.enpol.2011.09.039.
- Bridge to India. 2020. "India Solar Map." https://bridgetoindia.com/report/india-solar-map-december2020/.
- 447 CEA. 2019. "Annual Report." Delhi.
- Chen, Xiuzhi, Kelly R. Thorp, Zhiyun Ouyang, Yue Hou, Bo Zhou, and Yunkai Li. 2019. "Energy Consumption
  Due to Groundwater Pumping for Irrigation in the North China Plain." *Science of the Total Environment* 669 (June): 1033–42. https://doi.org/10.1016/j.scitotenv.2019.03.179.
- 451 DSUSM. 2017. "Dhundi Solar Energy Producers' Cooperative Society."
- 452 Energy Analytics Lab. 2020. "State Level Dashboard." 2020. https://eal.iitk.ac.in/home.php.
- 453 Energy Exemplar. 2021. "PLEXOS Market Simulation Software." 2021.
  454 https://energyexemplar.com/solutions/plexos/.
- 455 Gellings, C W. 1985. "The Concept of Demand-Side Management for Electric Utilities." *Proceedings of the* 456 *IEEE* 73 (10): 1468–70. https://doi.org/10.1109/PROC.1985.13318.
- 457 GERC. 2017a. "MYT Tariff Order, Paschim Gujarat Vij Company Limited (PGVCL)."
- 458 ———. 2017b. "MYT Tariff Order, Uttar Gujarat Vij Company Limited (UGVCL)."
- GOI. 2019. "Guidelines for Implementation of Component-C of PMKUSUM Scheme on Solarization of
   Grid-Connected Agricultural Pumps." New Delhi.
- 461 Gujarat SLDC. 2019. "Annual Report 2018-19."
- 462 Hirth, Lion. 2013. "The Market Value of Variable Renewables The Effect of Solar Wind Power Variability
  463 on Their Relative Price." *Energy Economics* 38: 218–36.
  464 https://doi.org/10.1016/j.eneco.2013.02.004.
- Hirth, Lion, Falko Ueckerdt, and Ottmar Edenhofer. 2015. "Integration Costs Revisited An Economic
  Framework for Wind and Solar Variability." *Renewable Energy* 74: 925–39.
- 467 https://doi.org/10.1016/j.renene.2014.08.065.
- Hummon, Marissa, David Palchak, Paul Denholm, Jennie Jorgenson, Daniel J Olsen, Sila Kiliccote, Nance
  Matson, et al. 2013. "Grid Integration of Aggregated Demand Response, Part 2: Modeling Demand
  Response in a Production Cost Model." *National Renewable Energy Laboratory*, no. December 2013.
  http://www.nrel.gov/docs/fy14osti/58492.pdf.
- 472 Hungerford, Zoe, Anna Bruce, and Iain MacGill. 2019. "The Value of Flexible Load in Power Systems with

- 473 High Renewable Energy Penetration." *Energy* 188: 115960.
- 474 https://doi.org/10.1016/j.energy.2019.115960.
- 475 IEA. 2020. "India Energy Policy Review." Paris.
- 476 ----. 2021. "Roadmap for System Integration of Renewables in India's RE Rich States" 2 (October
   477 2020). https://www.iea.org/events/power-system-transformation-workshop-2-state-of-gujarat.
- 478 IRENA. 2016. "Solar Pumping for Irrigation: Improving Livelihoods and Sustainability." www.IRENA.org.
- Kumar, N, P Besuner, S Lefton, D Agan, and D Hilleman. 2012. "Power Plant Cycling Costs Power Plant
   Cycling Costs," no. July.
- Kumar, Subhash, and Reinhard Madlener. 2016. "CO2 Emission Reduction Potential Assessment Using
  Renewable Energy in India." *Energy* 97 (February): 273–82.
  https://doi.org/10.1016/j.energy.2015.12.131.
- McPherson, Madeleine, and Brady Stoll. 2020. "Demand Response for Variable Renewable Energy
  Integration: A Proposed Approach and Its Impacts." *Energy* 197: 117205.
  https://doi.org/10.1016/j.energy.2020.117205.
- Olkkonen, Ville, Jussi Ekström, Aira Hast, and Sanna Syri. 2018. "Utilising Demand Response in the Future
   Finnish Energy System with Increased Shares of Baseload Nuclear Power and Variable Renewable
   Energy." *Energy* 164 (December): 204–17. https://doi.org/10.1016/j.energy.2018.08.210.
- Opejin, Adenike K., Rimjhim M. Aggarwal, Dave D. White, J. Leah Jones, Ross Maciejewski, Giuseppe
   Mascaro, and Hessam S. Sarjoughian. 2020. "A Bibliometric Analysis of Food-Energy-Water Nexus
   Literature." Sustainability (Switzerland) 12 (3): 1–18. https://doi.org/10.3390/su12031112.
- 493 PGVCL. 2020. "Power Supply Schedule for Agriculture Groups." 2020.
- 494 https://www.pgvcl.com/consumer/aglmu.pdf.
- 495 Pina, André, Carlos Silva, and Paulo Ferrão. 2012. "The Impact of Demand Side Management Strategies in
  496 the Penetration of Renewable Electricity." *Energy* 41 (1): 128–37.
  497 https://doi.org/10.1016/j.energy.2011.06.013.
- Shah, Tushaar, Shilp Verma, and Neha Durga. 2014. "Karnataka's Smart, New Solar Pump Policy for
   Irrigation." *Economic and Political Weekly* 49 (48): 10–14.
- 500Srikanth, R. 2018. "India's Sustainable Development Goals Glide Path for India's Power Sector." Energy501Policy 123 (December): 325–36. https://doi.org/10.1016/j.enpol.2018.08.050.
- 502Strbac, Goran. 2008. "Demand Side Management: Benefits and Challenges." Energy Policy 36 (12): 4419–50326. https://doi.org/10.1016/j.enpol.2008.09.030.
- Szinai, Julia K., Colin J.R. Sheppard, Nikit Abhyankar, and Anand R. Gopal. 2020. "Reduced Grid Operating
   Costs and Renewable Energy Curtailment with Electric Vehicle Charge Management." *Energy Policy* 136 (January): 111051. https://doi.org/10.1016/j.enpol.2019.111051.

- 507 Ueckerdt, Falko, Lion Hirth, Gunnar Luderer, and Ottmar Edenhofer. 2013. "System LCOE: What Are the
   508 Costs of Variable Renewables?" *Energy* 63: 61–75. https://doi.org/10.1016/j.energy.2013.10.072.
- 509 UGVCL. 2020. "Power Supply Schedule for Agriculture Groups." 2020.
- 510 http://www.ugvcl.com/ag\_power/time schedule.pdf.
- 511 Yang, Yulong, Kai Wu, Hongyu Long, Jianchao Gao, Xu Yan, Takeyoshi Kato, and Yasuo Suzuoki. 2014.
- 512 "Integrated Electricity and Heating Demand-Side Management for Wind Power Integration in
- 513 China." *Energy* 78 (December): 235–46. https://doi.org/10.1016/j.energy.2014.10.008.