Energy Policy 68 (2014) 158–169

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

When does unreliable grid supply become unacceptable policy? Costs of power supply and outages in rural India

Santosh M. Harish *, Granger M. Morgan, Eswaran Subrahmanian

Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA-15213, USA

HIGHLIGHTS

- We question the reliance on conventional grid in rural electricity supply in India.
- Alternatives compared through government subsidies and consumer interruption costs.
- Interruption costs are estimated based on loss of consumer surplus due to outages.
- Augmenting unreliable grid with local biomass or diesel based backups preferable.
- With efficient lighting, standalone biomass plants are optimal at very low distances.

ARTICLE INFO

Article history:
Received 24 September 2013
Received in revised form
22 January 2014
Accepted 24 January 2014
Available online 19 February 2014

Keywords:
Rural electrification
India
Unreliability
Consumer interruption costs
Energy efficient lighting

ABSTRACT

Despite frequent blackouts and brownouts, extension of the central grid remains the Indian government's preferred strategy for the country's rural electrification policy. This study reports an assessment that compares grid extension with distributed generation (DG) alternatives, based on the subsidies they will necessitate, and costs of service interruptions that are appropriate in the rural Indian context. Using cross-sectional household expenditure data and region fixed-effects models, average household demand is estimated. The price elasticity of demand is found to be in the range of −0.3 to −0.4. Interruption costs are estimated based on the loss of consumer surplus due to reduced consumption of electric lighting energy that results from intermittent power supply. Different grid reliability scenarios are simulated. Despite the inclusion of interruption costs, standalone DG does not appear to be competitive with grid extension at distances of less than 17 km. However, backing up unreliable grid service with local DG plants is attractive when reliability is very poor, even in previously electrified villages. Introduction of energy efficient lighting changes these economics, and the threshold for acceptable grid unreliability significantly reduces. A variety of polices to promote accelerated deployment and the wider adoption of improved end-use efficiency, warrant serious consideration.

1. Introduction

About 45% of the 168 million rural households in India remain unelectrified (Census of India, 2011). Since the adoption of the Electricity Act of 2003 and the Rajiv Gandhi *Grameen Vidyutikaran Yojana* (Rural Electrification Program) (RGGVY) in 2005, rural electrification (RE) has received renewed attention with significant government funding and ambitious targets. When it was launched, the goal of the RGGVY was to electrify *all* villages by 2012, although at the time 26% of the 600 thousand villages in the country and 56% of rural households were unelectrified (Prayas Energy Group, 2011). The apparent discrepancy between the village and household figures is because a village is deemed electrified if 10% of its households are electrified and the basic infrastructure installed. Using this metric, 'village electrification' levels have now increased to almost 93% (Ministry of Power (MOP) website).

However, the quality and reliability of electricity supply remains poor in many parts of the country. Even the limited goal of guaranteeing at least 6 h of daily supply has not been met in some states (Udupa et al., 2011). For example, Oda and Tsujita (2011) estimated that villages surveyed in the state of Bihar in 2008–2009 received, on average, 6.3 h of daily supply in "good months" and 1.3 h in "bad" ones. The extension of the central grid

* Corresponding author. Tel.: +1 302 438 5252.
E-mail address: sharish@andrew.cmu.edu (S.M. Harish).

http://dx.doi.org/10.1016/j.enpol.2014.01.037
0301-4215

has been the primary route of electrification under the RGGVY, despite the known limitations with the supply. As the intended targets have not been achieved, the program is very likely to get extended beyond 2012. In parallel, the Ministry of New and Renewable Energy (MNRE) has begun extending support to solar lighting systems under the National Solar Mission (Ministry of New and Renewable Energy (MNRE), 2010), and is also looking to revamp the Remote Village Electrification (RVE) program (Ministry of New and Renewable Energy (MNRE), 2012).

Much of the analysis on rural electrification routes has focused on costs of supply and the distance beyond which extension of feeders is more expensive than the adoption of distributed generation plants (e.g. Sinha and Kandpal (1991), Banerjee (2006), Nouni et al. (2009)). Here we ask when the standard mode of grid extension is not the optimal choice if the costs of unreliable supply are included. There are two related research questions: (1) for villages that have not been electrified, how unreliable must conventional grid be, both currently and in the foreseeable future, for one to consider an alternative, local source of generation; (2) for villages that are already electrified by the grid, how unreliable must the supply be before one should consider augmenting it with an additional local source of power.

We compare conventional grid extension with standalone distributed generation (DG) plants as well as "grid-plus" options which involve augmenting the central grid with local DG plants. The alternatives are compared based on 'societal costs'—the sum of the necessary subsidies borne by the government, and the costs incurred by customers that result from unreliable supply. This societal cost framework is analogous to estimating the 'cost' of subsidizing more reliable supply that has the 'benefit' of reducing consumer interruption costs, with the aim of identifying the 'optimal' alternative with the highest net benefit to society. We explore which alternatives, if any, have higher net benefits when compared to conventional grid extension with erratic supply.

Section 2 describes the methods and data used in this study. Section 3 discusses the results of our analysis and explores the sensitivity of the choice of each alternative to different levels of grid supply availability as well as demand side measures such as policies encouraging efficient lighting. Section 4 provides a discussion on the broader policy implications of the results for rural electrification policy.

2. Methods

Section 2.1 discusses the problem formulation in this study—Sections 2.1.1, 2.1.2 and 2.1.3. Section 2.2 describes the estimation of electricity demand and its price elasticity from sample survey data. Section 2.3 elaborates the methods for estimating subsidy and consumer interruption costs.

2.1. Problem formulation

2.1.1. The decision maker(s)

Electricity falls under the jurisdiction of the central (federal) and state governments. As a result, multiple decision makers with different perspectives on the objective have to be considered.

Under the rural electrification (RE) policy currently operationalized by RGGVY, the central MOP funds 90% of the capital costs of the infrastructure in electrifying a new village. Grid extension is the "normal way of electrification" (Ministry of Power (MOP), 2006). The choice of which villages are to be electrified by the grid, and implementation, are both left to the state governments and the state-owned distribution utilities. State governments may choose to support the remaining 10% of the infrastructure costs; otherwise, the remaining costs can be passed down to the consumers. Villages deemed too remote or unviable for grid extension, can be covered under RGGVY's DG program or under the central MNRE's RVE program. Both these programs cover 90% of the (higher) costs of the DG plants. As the capital costs are funded upfront, the tariffs in the case of grid extension or DG reflect only the costs of operation and maintenance, fuel, and power purchase, as applicable.

The federal government has a limited role in the subsequent supply of electricity. In the case of DG plants, it supports the difference between the recurring costs of supply and tariffs set by the project developers in consultation with state government authorities. With grid extension, for a utility to receive capital subsidies from the Center, the federal government only requires that utilities provide a minimum of 6–8 h of supply per day to villages chosen for grid electrification. There are no apparent penalties if, after grid extension, this condition is not met.

Tariffs are proposed by distribution utilities and regulated by state regulatory boards. With most of the generation sourced within a given state, power purchase costs differ by state. Tariffs are subsidized for domestic and agricultural consumers, partly due to equity concerns and partly due to their populist appeal. The domestic tariffs are cross-subsidized by charging commercial and industrial consumers tariffs that are greater than costs of supply. Subsidies for the poorest domestic consumers and agricultural consumers are funded by the state governments. Agricultural pump-sets, that are large loads, form a particularly problematic category. Even when they are charged for supply, they only pay flat annual charges, and typically are unmetered. As a result, distribution utilities, facing both power deficits and financial losses, have an incentive to "load shed" rural areas more than urban or industrial consumers.

While this study considers the priorities of these different stakeholders, our analytic formulation adopts the perspective of a single composite decision maker who is trying to achieve an optimal social outcome that minimizes the subsidies required over a long term, while providing reliable supply. Following the RGGVY's priorities, we focus only on residential and communal loads. Agricultural loads are not considered.

2.1.2. Alternatives

In recent years, with the dramatic drop in photovoltaic (PV) prices (Aanesen et al., 2012), solar home lighting systems and village level micro-grids have become more popular. The current RE program allows for DG, using micro-hydro, biofuel, biomass gasification or solar PV based generation, to be used where grid supply is deemed infeasible (Ministry of Power (MOP), 2006). These are allowed recognized because they are relatively mature, both technologically and commercially. In this study, only biomass gasification and solar PV have been included as the resources are available in most parts of the country, and several private micro-grid firms already use these technologies.

In our analysis, we consider five electrification routes:

(1) Grid extension involves installing pole-mounted 11 kV feeder lines, local transformers (11 kV/400 V) and a low voltage distribution network. Setting up sub-stations is sometimes necessary while electrifying new areas but these are assumed to exist in this analysis.
(2) A biomass gasification plant converts waste products from agricultural processes, or energy crops grown for the purpose, into producer gas which is then used in an internal combustion engine. There are two primary parts of the gasification system – the gasifier which includes fuel processing and preparation units – and the generator engine.

(3) Solar PV systems consist of PV modules which convert solar energy into electrical energy, a charge controller that regulates the system to prevent damage, a battery to store the energy, and a power conditioning unit or an inverter to convert the DC to AC. While DC could be used directly, especially for lighting, this has not been common practice.
(4) Diesel DG plants with a generator that runs on diesel alone. The price of diesel is regulated in the country and is subsidized. Diesel generators, while widely used, are not encouraged under RGGVY as a primary DG source because of their environmental and fiscal implications.
(5) Grid extension backed up with local DG plants. The generators are sized to meet the entire daily load of the village. The supply mix from the central grid and the DG plant is optimized to minimize the costs of supply. Power generated by the DG is not exported to the grid.

In this analysis, the biomass and solar PV standalone plants are assumed to have diesel backup generators to mitigate constraints in fuel supply or insufficient sunshine. The sizing of backup generators is for the aggregate daily peak load and this redundancy ensures that the standalone DG plants are close to perfectly reliable.

2.1.3. Metrics-societal costs

The alternatives are compared based on societal costs computed as the present value of the sum of the capital subsidies received by the utilities, and supply interruption costs experienced by the consumers. These two costs are borne by two very different groups of stakeholders. Weighting them equally prioritizes reliable energy access in a very different way than that implied by current policy. We are essentially assuming that society should value the reliability of the supply to the consumer to the same degree as consumers themselves (although perhaps with a different time value of money).

2.1.3.1. Subsidy costs. Subsidy costs are computed as the present value of the unrecovered costs of supply. To do this, we consider a constant, flat tariff. Monthly household demand is estimated as a function of this tariff using a cross-sectional dataset as described in Sections 2.2.1 and 2.2.2. The estimates of load profiles are based on assumptions regarding the distribution of demand through the average day as well as village size and community facilities. The plants are sized to match the peak aggregate demand in the village. Estimates of supply costs are a function of cost schedules of the alternatives and the assumed aggregate load profile. The costs of supply depend on the tariffs, the costs of components and fuel, the village size, as well as the nature of the household demand. For example, the efficiency of the lighting appliances used may dramatically affect the supply costs of the alternatives, as described in Section 3.

2.1.3.2. Interruption costs. The method adopted to assess interruption costs is based on an estimate of forgone consumer surplus, rather than an elicitation of willingness to pay (WTP) which has become the more standard approach (Lawton et al., 2003; Woo and Pupp, 1992). As ability to pay is the primary constraint in an RE context and rural households tend to overestimate their WTP, survey responses may be misleading (Cust et al., 2007). With uninterrupted supply, consumption will be a function of tariff. The value of the forced decrease in usage will then be the area under the demand curve between this reduced usage and the estimated usage with uninterrupted supply (i.e., demand). The interruption cost is then the lost surplus, if there is no alternative for the foregone service. If a back-up service is used, the interruption cost would be the net of lost surplus and the surplus associated with the back-up source.

Woo and Pupp (1992) identify three broad techniques for estimating interruption costs-proxy based, consumer surplus and contingent valuation methods. The approach used here combines the consumer surplus method of estimating interruption costs, with the proxy method of considering costs of backup. Service unreliability and its implications on rural residential loads in the developing world have not witnessed a significant body of work. The exceptions are Sarkar (1996) (contingent valuation) and Kanase-Patil et al. (2010) (proxy based). In the RE context, consumer surplus methods have been used by Munasinghe (1988), van den Broek and Lemmens (1997) and World Bank (2008) to quantify the benefits of rural electrification.

While we believe it is superior for our purposes, the approach of using consumer surplus involves a number of limitations. First, reduction in planned consumption due to tariff increases is not equivalent to forced reduction in consumption due to outages (Munasinghe and Gellerson, 1979; Woo and Pupp, 1992). Estimating lost surplus based on the former underestimates the latter. Second, non-linear demand curves, especially double log functions, can overestimate the lost surplus because the demand reduces to zero only when the cost per unit tends to infinity (Woo and Pupp, 1992; IAEA, 1984). Third, Munasinghe and Gellerson (1979) suggests that the consumer surplus method inherently assumes that electricity is a product, and not an intermediate service for a productive activity. Fourth, the demand curves used must correspond to the periods of loss for the outage costs for the estimated costs to be appropriate. In our analysis, while the first limitation remains, intermediate modifications and assumptions are made to address the other three.

To differentiate outages of different durations and frequencies starting from an aggregate monthly demand curve, we need to define the smallest interval of time for which there is an 'independent' demand curve. Such an interval should satisfy two conditions.

1. Consumption in this interval is valued independently of consumption in any other period.
2. Demand in a subset of this interval is valued as a function of consumption in the rest of the interval.

If there is an order of priority for the activities that require electricity within this interval, there will be a diminishing marginal utility for electricity consumed. This formulation requires the consumers to be able to reschedule their activities dynamically in this order of priority such that any consumption denied, due to outages, will be treated as the marginal unit denied. We assume that this interval is a day—that is, a monthly demand curve is composed of 30 identical, 'independent' daily demand curves. While the values of forced reduction in usage due to a daylong outage is estimated as in Fig. 1(a), the values of outages within a day aggregate as shown in Fig. 1(b). The latter formulation requires the consumers to be able to reschedule their activities based on the availability of supply, such that they 'do more' when supply is available. This does not necessarily imply consuming more electricity when supply is available. In fact, we make the conservative assumption that outages have no impact on the usage in periods with supply.

The demand curve required for calculating these interruption costs is estimated based on the household data and regressions discussed in Section 2.2. Additional assumptions and modifications are also made as discussed in Section 2.3.2.

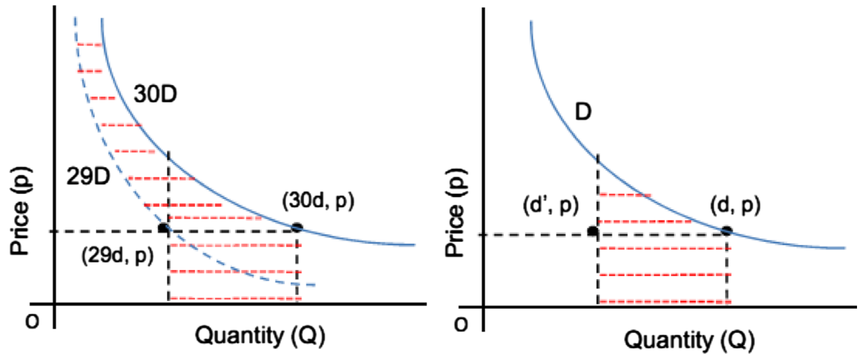

Fig. 1. Illustration of the assumed valuations of day long outages (left) or for a few hours during the day (right).

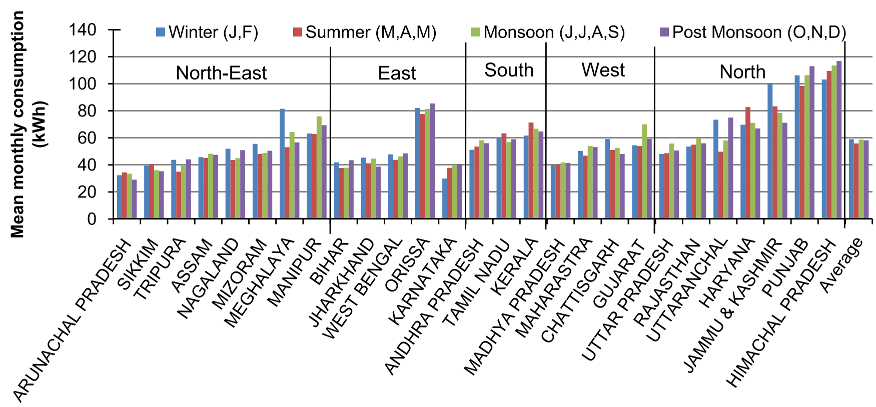

Fig. 2. Mean reported household consumption over the four seasons for different states.

2.2. *Estimating electricity demand*

The principal objective of this part of the analysis is to estimate household demand as a function of tariff. The analysis is based on household data collected by the National Sample Survey Organization (NSSO) in their 2009–2010 surveys. These sampling surveys are conducted every five years. They collect data on consumption expenditure from over 100,000 households, including about 59,000 rural households) from all the districts in the country. The analysis uses district level mean values for the relevant variables, resulting in 593 data points for the regression.

2.2.1. *Summary of data used*

The household surveys were done by NSSO over the course of a year, and the electricity consumption data were based on a 30 day recall period. Each respondent was surveyed only once, but sampling was done in each district throughout the year. To check whether there are discernible seasonal patterns that are missed while using district means, the dates of surveys were used to categorize the observations into different seasons. The average consumptions across the four seasons (as per the Indian Meteorological Department) are reported in Fig. 2. Average monthly household consumption in most of the states is less than 60 kW h/month. While, the national averages are almost constant across the seasons, some spikes in consumption during winters occur in a few states in the north and north-east. Cross state variations in consumption of power are neglected in the rest of the analysis for simplification.

Tariff structures are regulated by bodies at the state level, and cross state variations in tariffs facilitate the cross-sectional analysis here. The national mean is Rs. 2.4/kW h, and the average tariffs range from Rs. 0.7/kW h in Pondicherry to Rs. 3.8/kW h in Rajasthan. These average tariffs have been estimated using reported monthly expenditure on, and consumption of, electricity. As state level tariffs have a multi-part structure, the average tariffs may depend on the consumption. However, the standard deviations were less than 5% of estimated mean tariffs in most states, and within 10% for all. As the estimated tariffs fall within a narrow range, it seems reasonable to treat the tariffs as independent of consumption, and ignore simultaneity issues.

2.2.2. *Regressions*

A simple population model should suffice in estimating price elasticity as long as there are no omitted variables that are correlated with the tariffs. For example, while average monthly per capita total expenditure (*MPCE*) is positively correlated with average monthly electricity consumption, it has close to zero correlation (0.01) with the average tariffs. Hence, MPCE need not be included in our regression models. On the other hand, the fraction of rural households owning televisions (*PropTV*) is both positively correlated with consumption and moderately negatively correlated with tariffs, and hence, has to be included.

To estimate demand based on usage data, we need to control for unreliability in the supply. For demand estimation, we use state-specific estimates of deficits as a fraction of demand at peak loading (*PeakDeficit*), as estimated by the Central Electricity Authority (CEA) for the months of May 2009–April 2010 (the period of the surveys). On average, only 87% of the peak demand was met. In the state of Bihar, only 66% of the demand was met, while supply in states like Gujarat and Himachal Pradesh met peak demand. As the rural residential peaks coincide with the aggregate peaks, and as utilities "load shed" more from rural areas during these times, *PeakDeficit* is a reasonable proxy for the supply availability.

Regressions using ordinary least squares (OLS) and fixed effects by region (region FE) have been used to estimate the demand curve. The 'regions' identified are as defined by the CEA. The region FE model helps avoid biases due to omitted variables that are constant in a given region. This includes weather conditions and electrification levels over time. A double log formulation has been used, implicitly assuming a constant price elasticity of demand. The population model assumed is

$$\ln(Elec.\ Usage)_{ij} = \alpha_0 + \alpha_t \ln(Tariff)_{ij} + \alpha_{pd}(Peak\ Deficit)_{ij} + \sum \alpha_i X_{ij} + r_j + \epsilon_{ij} \quad (1)$$

where X_{ij} are average demographic characteristics or electrical appliance ownership in district i of region j. r_j are regional unobservables, and ϵ_{ij} are idiosyncratic errors. We use district level means of the variables (except for *PeakDeficit*). Since the primary variable of interest is the tariff, only those variables that were found to be correlated with it have been included. The results are shown in Table 1.

All coefficients have the appropriate sign. The price elasticity of demand is estimated to be about −0.2 with the OLS approach and between −0.3 and −0.4 with the FE model. The latter is slightly higher (that is, more elastic) than estimates in literature in the developed country context (for example, Azevedo et al. (2010)). Price elasticities of demand have been previously estimated for Indian households by Fillipini and Pachauri (2004) (−0.29 to −0.51), Tiwari (2000) (−0.7) or Gundimeda and Kohlin (2008) (−0.59 to −0.72). Of these, only the last estimate corresponds to rural households. An increase in deficits by 10% reduces consumption by about 10%.

Subsequent analysis will use results from model 4 in Table 1 using region FE (with *Tariff*, *PropTV*, and *PeakDeficit*). We adjust for reliability using the *PeakDeficit* proxy variable. The estimated demand curve, juxtaposed with state level means of consumption and tariff, is shown in Fig. 3. The estimated demand at Rs. 2.5/kW h is about 58 kW h, close to the national mean consumption.

2.3. Estimating societal costs-methods

2.3.1. Subsidy costs

Subsidy costs are a function of the costs of supply, the tariffs charged and the consumption.

Aggregate load profiles are required for sizing the plants, and affect significantly the costs and profitability of providing supply. In the rural Indian context, the residential demand tends to be greatest in the early mornings and evenings. The two primary uses of electricity are for lighting and televisions. The demand is assumed equal (on average) for each day of the month, and monthly or seasonal variations are not considered. Hourly load profiles are assumed constant on average during the course of a year. The data used for making the estimates are not restricted to newly electrified households; the sampled households are likely to have been electrified at different times. Hence, demand growth over time has not been included here. Inputs for *Tariff* and *PropTV* were based on NSSO data. To estimate aggregate load profiles, some additional community facilities with representative loads have been included. The detailed assumptions are documented in Appendix A.

Table 1
Results of the OLS and region fixed effects regression models for ln(*Elec. Usage*)—coefficients with robust standard errors ($n = 592$).

	OLS		Region FE		
	Model 1	Model 2	Model 3	**Model 4**	Model 5
ln(*tariff*)	−0.181***	−0.199***	−0.384**	**−0.343****	−0.324**
	(0.037)	(0.035)	(0.118)	**(0.098)**	(0.078)
PropTV	0.558***	0.396***	0.521***	**0.540*****	0.413***
	(0.075)	(0.077)	(0.089)	**(0.087)**	(0.061)
ln(*mpce*)		0.354***			0.342**
		(0.053)			(0.095)
PeakDeficit	0.663***	0.511***		**0.869***	0.826
	(0.178)	(0.163)		**(0.358)**	(0.420)
Constant	3.861**	1.508***	3.977***	**4.043*****	1.734*
	(0.069)	(0.359)	(0.133)	**(0.113)**	0.666)
R^2	0.19	0.28	0.31	0.34	0.42

*** $p < 0.01$.
** $p < 0.05$.
* $p < 0.1$.

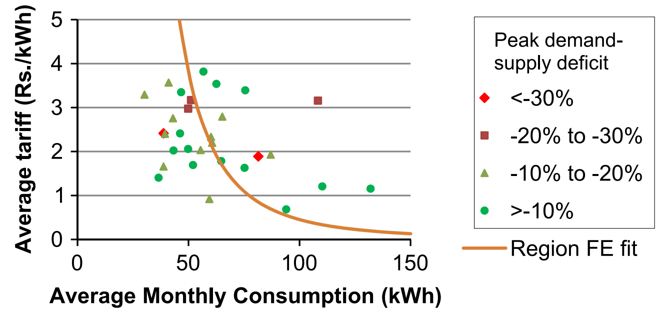

Fig. 3. Estimated demand curve, along with state level means of consumption and peak deficit.

The required plant size is estimated using the peak aggregate demand and an approximate distribution loss. The actual size of the plant for a given alternative would also be constrained by the available module sizes of generators, batteries or transformers. For solar PV, the required panel size and battery capacity need to be estimated using additional inputs on component efficiencies and losses. The formulae and assumptions are listed in Appendix B.

It is assumed that outages are a characteristic of the alternative. For DG, fuel availability (or in the case of solar, sufficient sunshine) throughout the year could be a problem. Hence, we assume that biomass and PV DG plants are backed up by a diesel generator so that the combined design is reliable. In the case of the central grid, it is assumed that outages are independent of the local consumption. This is reasonable since rural domestic consumption is a very small fraction of the overall demand (in contrast to agricultural demand that we are not considering here).

In the absence of more detailed data, the availability of grid power is characterized in terms of daily hours of supply, number of days of blackouts per month, and number of years in the future when grid-power is likely to become reliable. There are some data reported to support the estimates for the first two (for example, Udupa et al. (2011)), the third is treated as an uncertain parameter. While unreliable supply is a consequence of limited generation capacity, it also depends on political priorities and the incentives faced by utilities. The availability scenarios (besides that of uninterrupted supply) are summarized in Table 2. RGGVY mandates a minimum of 6–8 h of supply per day. However, there is no requirement for this to coincide with the times of maximum demand. Often, grid supply is provided late in the night or in the afternoon hours, when there is little or nothing useful that a household can do with the power.

For grid supply, consumption in year t will be constrained by availability as

$$c_t = \sum_{h=1}^{24} (D^k_{agg,h} \times s^k_{h,t}) \times (365 - num^k_{blackout,t} \times 12) \quad (2)$$

where $D^k_{agg,\,h}$ is the estimated aggregate load at hour h in the supply scenario k and $s^k_{h,t}$ is a binary variable (0 or 1) representing whether grid supply is available then or not. $num^k_{blackout,t}$ is the number of entire days of no supply per month in year t. The k

Table 2
Reliability scenarios considered.

	'Poor' quality	'Intermediate' quality
Daily hours of supply	Six hours in all: 3 in the peak period- 1 in the evening, 2 morning; 3 h in the rest	Eighteen hours in all: Single phase: 6 PM–6 AM; Three phase: 6 AM–12 noon
Average day-long outages/month	5	2
Years required for grid to become reliable	10 (2–10)	5 (2–10)

scenarios include the uninterrupted, 18-h and 6-h scenarios as described in Table 2. With DG, consumption will be identical to uninterrupted grid availability scenario. Appliance ownership is assumed to be unaffected by the intermittency in supply.

The cost estimation methodology follows from prior literature. A detailed description of the cost inputs and assumptions for each alternative is provided in Appendix C. The subsidy costs are estimated over a 10 year period, using a real discount rate of 10%. As the lifetimes of some of the components are higher, their capital costs are annualized.

The levelized cost of energy (LCOE) is estimated as,

$$\text{LCOE} = \sum_{t=1}^{10} \frac{x_{cap-ann} + x_{O\&M} + x_{fuel\ t}(or, x_{gridpower,t})}{(1+r)^t} \Big/ \sum_{t=1}^{10} \frac{c_t}{(1+r)^t} \quad (3)$$

$x_{cap\text{-}ann}$ are the annualized capital costs of the infrastructure for a given alternative, $x_{O\&M}$, the annual operation and maintenance costs, $x_{fuel,t}$ the costs of the fuel in the plants in year t and $x_{gridpower,t}$ the costs of supply for the utilities. r is the discount rate used.

Although the LCOEs could be computed for the unreliable grid supply scenarios as well, comparisons are not entirely meaningful when their denominators vary. As a result, the analysis here considers the subsidy costs instead.

$$\text{Cost of subsidy} = (\text{LCOE} - Tariff) \sum_{t=1}^{10} \frac{c_t}{(1+r)^t} \quad (4)$$

Interestingly, in terms of subsidy costs, providing unreliable grid supply is cheaper for the utilities than providing uninterrupted supply from the grid or through DG. As the costs of power purchased contribute a significant amount to the LCOE of grid supply, and because the tariffs tend to be lower than costs of supply, subsidy costs favor extending the grid, over DG alternatives, despite the former's poor reliability. To make reasonable comparisons, interruption costs must be considered.

2.3.2. Interruption costs

Following the earlier discussion, interruption costs are estimated based on loss of consumer surplus using daily demand curves. As a simplification, the interruption costs are estimated based on lighting in the 'peak' hours alone. Hence, the consumption in this case could alternatively be measured using kilolumen-hour, i.e. total light output 'used' over time. While such an estimate would at best be a lower bound, lighting is the primary domestic end-use of electricity in rural India. In the absence of reliable electricity, different back-up sources of lighting are used which help in understanding the willingness to pay and validating the estimates.

While the demand curves from Section 2.2.2 provide the foundation of the interruption costs estimate, modifications are made at low consumption where the double-log curve will overestimate the consumer surplus. Two constant expenditure lines of Rs. 200/month and Rs. 300/month are used as bounds. These correspond to estimated expenditures at Rs. 4/kW h and Rs. 8/kW h, and are in the ballpark of the amortized costs of solar lanterns and lighting systems that are becoming increasingly popular as primary and backup lighting. [1]

It is assumed that during outages, kerosene lanterns are used. As the light output is very low, the value of consumption of kerosene will be very low but bound the interruption costs from going to infinity. As a result, the interruption costs will now comprise the value lost by consuming kerosene lighting and not electricity, and net costs of the backup lighting energy source (that is, expenditure on kerosene less the saved expenditure on unconsumed electricity).

Based on demand as a function F of tariff, annual interruption cost is estimated as,

$$x_{\text{int}\ erruption} = \left(\frac{(30 - num^k_{blackout,t})}{30} \int_{e'_T}^{e_T} F^{-1}(l)dl + \frac{(num^k_{blackout,t})}{30} \int_{e_{\text{kerosene}}}^{e_T} F^{-1}(l)dl + x_{\text{kerosene}} - (e_T - e'_T)p_e \right) \times 12 \quad (5)$$

where e_T, e'_T and $e_{kerosene}$ are the consumption of lighting energy (in klm-h, say) with uninterrupted supply at tariff p_e, with unreliable supply, and forced usage of kerosene due to outages, respectively

$$x_{\text{kerosene}} = (6num^k_{blackout,t} + (30 - num^k_{blackout,t})(6 - \textstyle\sum_{h \in peak} s^k_{h,t})) \times p_{\text{kerosene}} \times \eta_{\text{kerosene}} \times lanterns \quad (6)$$

$p_{kerosene}$ is the price of kerosene. Up to 4 l/month, subsidized kerosene at Rs. 15/l is available, and beyond that kerosene must be purchased in the market at Rs. 25/l.

$\eta_{kerosene}$ is the fuel efficiency of kerosene lanterns. A mass-manufactured "hurricane" lantern consumes 0.03 l/h (Mills, 2003).

The variable *lanterns* is the number of kerosene lamps. It is assumed that two lamps are used during outages. With higher numbers, kerosene consumption becomes impracticably high, especially in the 6 h supply scenario

By design, the interruption cost will be zero in the case of uninterrupted grid and decentralized plants. For unreliable grid supply, these costs will be positive. The estimated consumption in the base-case with the different unreliable scenarios is shown in Fig. 4. Table 3 summarizes estimated costs for a few blackout events. Because of our assumptions, the interruption cost per unit time (or per unit consumption denied) increases with the cumulative duration of the outages within a single day.

3. Results and discussion

Table 4 summarizes the inputs for the 'base case'. Based on these inputs, the peak aggregate demand is 63 kW, and the total daily consumption is about 420 kW h.

[1] We assume that the cost of the solar lighting system is Rs. 12,000- purchased through a loan with a term of 5 years, at 12% interest rate, and 20% down-payment. Such a lighting system typically has 3–4 CFL lights. A system lifetime of 10 years is assumed, with a battery lifetime of 6–8 years (replacement costs of Rs. 4000). A solar lantern costs Rs.1600 and is assumed to be purchased with a one-time cash transaction. The lifetime of such a product is assumed 3–5 years, and the battery is replaced every year at a cost of Rs. 150. Based on these cost assumptions and discount rates at 30–60%, the amortized monthly costs of purchasing a solar lighting system is Rs. 275–370, and two solar lanterns is Rs. 130–265. Purchase of a solar product would imply high upfront costs, and the consumer will likely use a significantly higher discount rate than the social planner's 10%. Ekholm et al. (2010) use discount rates of 62–74% for rural households and 53–70% for urban. Reddy and Reddy (1994) estimate an internal rate of return of 28% for a switch from kerosene lamps to electricity- which could be a lower bound on the discount rate.

Combining the interruption costs with the subsidy costs, the alternatives are compared in Table 5. The present value of subsidy, interruption and societal costs are expressed per electrified household.

Even after including interruption costs, the DG plants are still too expensive from a societal standpoint. While subsidy costs of grid extension are sensitive to distance, biomass-diesel (the cheapest of the three DG plants) is competitive with the 6-h supply only beyond 17 km. However, RGGVY project reports (from MOP's RGGVY website) suggest that grid extension beyond 5 km is very rare- required for less than 10% of unelectrified villages in the three most poorly electrified states. On the other hand, the backup alternatives look more attractive. As grid costs are common for both, the outage costs of unreliable supply are compared with the additional cost of backing-up. As a result, these comparisons are independent of grid extension distance and would also apply to villages already connected, whether the grid infrastructure is considered as a sunk cost or not.

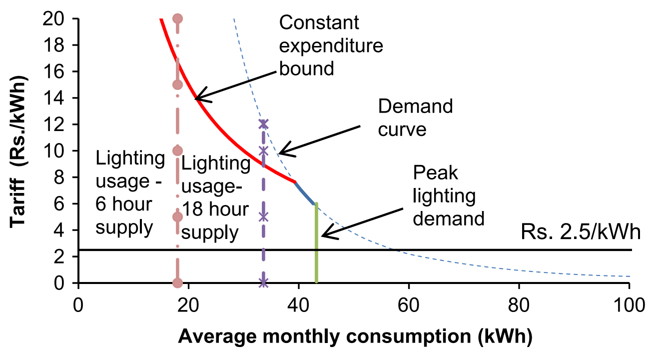

Fig. 4. Lighting usage with intermittent supply.

Table 3
Estimated interruption costs for a few examples.

Event	Estimated interruption cost	
	Rs.	Rs./kW h denied
Any frequency of any duration of outages in the non 'peak' hours	0	0
Thirty minutes at peak	0.6–0.8	4.8–6.6
One hour during peak	1.2–1.7	5.1–7.3
Two hours during peak	2.7–4	5.6–8.3
One day (or all 6 h of peak)	29–79	20–55

Table 4
Assumptions used for the base case.

Average tariff, *Tariff*	Rs. 2.5/kW h
PropTV	60%
PeakDeficit	0% (Perfectly reliable)
Lighting usage threshold, *L*	43.2 kW h (4 × 60 W lamps)
Average TV usage, *TV*	5.8 kW h (80 W load)
Peak hours	5–7 am; 6–10 pm
Evening hours	6–10 pm
Night hours	10 pm–5 am
Number of households	200
Distance of village from grid (Length of 11 kV line needed)	3 km

Fig. 5 compares the societal costs of grid extension with and without backup. Because 6 h/day is used as a benchmark in rural electrification planning, the alternatives compared here all assume 6 h of grid availability but differ in the number of hours in the peak period. Biomass capital costs are high, and hence for optimum operations, if installed it should be used as much as possible, subject to fuel availability. Biomass alone (assuming sufficient fuel availability) costs Rs. 27,000 per household, or in terms of LCOE, Rs. 8.2/kW h. That will be cheaper than any grid-biomass backup combination. When being used as a backup as well, the optimal operations entail using the available grid supply only to spread the availability of biomass throughout the year. Hence, in Fig. 5, societal costs of the grid-biomass alternative are independent of reliability.

Table 6 summarizes the least expensive alternative for different grid availability combinations. If grid extension is suboptimal, all alternatives preferable to grid are listed. Once again, the results in Table 6 are for the 6 h supply case alone. As the interruption costs are being estimated only based on availability in the peak demand period, they will not be affected with greater grid availability through the day. However, subsidy costs will increase, and hence, so too will the total societal costs of grid power. Grid-biomass costs should remain unaffected, and hence become marginally more attractive. The results in Table 6 assume the base case daylong outages per month for 6 h supply, but the results are sensitive to these as shown in Table 7.

Because of low initial cost, at present most rural lighting uses incandescent bulbs. Replacing them with energy efficient lighting could have a substantial impact on the economics of the alternatives.

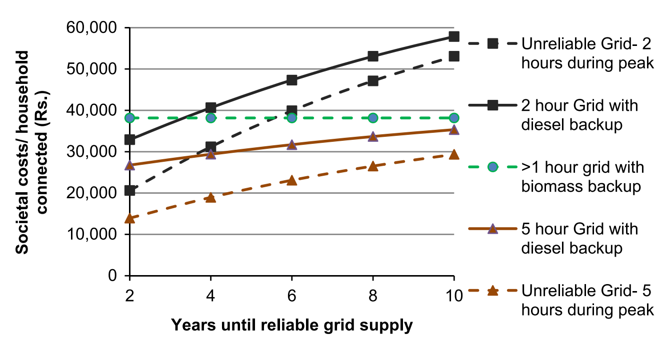

Fig. 5. Sensitivity of societal costs of grid supply, with and without backup, to reliability (receiving 6 h grid supply on average per day but differing in number of hours of supply in the peak hours).

Table 5
Summary of societal costs in the base case.

Alternative		Cost of subsidy (Rs.)	Outage cost (Rs.)	Societal costs (Rs.)
Uninterrupted grid supply		7,800	–	**7,800**
Eighteen hours grid supply	Without backup	7,400	5,100–7,200	**12,500–14,600**
	With diesel backup	27,000	–	**29,300**
Six hours grid supply	Without backup	6,100	26,200–36,700	**32,300–42,800**
	With biomass backup	38,200	–	**38,200**
	With diesel backup	49,800	–	**49,800**
Biomass- diesel DG plant		55,400	–	**55,400**
Diesel DG plant		79,600	–	**79,600**
Solar- diesel DG plant		147,000	–	**147,000**

Table 6
Alternative with least societal cost for different reliability scenarios (grid availability for 6 h/day on most days, but differing availability during peak demand).

		Years for reliable grid supply			
		< 4	6	8	10
Hours of grid availability in peak demand period (6 h)	2	Grid	Biomass backup (Grid)	Biomass backup (Grid)	Biomass backup (Grid)
	3	Grid	Grid	Grid	Biomass backup (Grid)
	≥ 4	Grid	Grid	Grid	Grid

Table 7
Sensitivity to number of daylong outages per month- alternative with least societal cost for different reliability scenarios (grid availability for 6 h/day on most days; differing availability during peak demand; supply becoming reliable after 6 years).

		Number of daylong outages/month				
		Upper bound of interruption costs			Lower bound of interruption costs	
		0–2	5	10	0–5	10
Hours of supply in peak demand period	2	Grid	Biomass backup	Biomass or Diesel backup	Grid	Biomass backup
	3	Grid	Grid	Biomass or Diesel backup	Grid	Grid
	≥ 4	Grid	Grid	Diesel backup	Grid	Grid

Table 8
Alternative with least societal cost for different reliability scenarios with CFL lighting (grid availability for 6 h/day on most days, but differing availability during peak demand). Biomass DG plant is not competitive with the grid at reasonable distances (*) or is optimal beyond 1 km ([1]), 3 km ([3]) and 5 km ([5]) or at any distance ([0]).

		Years for reliable grid supply				
		2	4	6	8	10
	Upper bound of interruption costs					
Hours of grid availability in peak demand period (6 h)	2	Diesel backup[1]	Diesel backup[0]	Biomass or Diesel backup[0]	Biomass or Diesel backup[0]	Biomass or Diesel backup[0]
	3	Grid[5]	Diesel backup[0]	Diesel backup[0]	Diesel backup[0]	Biomass or Diesel backup[0]
	4	Grid*	Diesel backup[0]	Diesel backup[0]	Diesel backup[0]	Biomass or Diesel backup[0]
	5	Grid*	Diesel backup[3]	Diesel backup[0]	Diesel backup[0]	Diesel backup[0]
	Lower bound of interruption costs					
	2	Grid*	Grid[0]	Biomass or Diesel backup[0]	Biomass or Diesel backup[0]	Biomass or Diesel backup[0]
	3	Grid*	Grid[3]	Grid[0]	Diesel backup[0]	Biomass or Diesel backup[0]
	4	Grid*	Grid[5]	Grid[3]	Grid[1]	Diesel backup[0]
	5	Grid*	Grid*	Grid**	Grid[5]	Grid[3]

Hence, we study how a switch to compact fluorescent lamps (CFL) affects the costs through a reduction in demand. While incandescent lamps are assumed to have a luminosity of 12 lm/W, CFL are assumed to provide 50 lm/W (based on Azevedo et al. (2010)). Rebound in consumption is parameterized. With zero rebound, the estimated monthly household demand in the base case reduces from 58 kW h to 25 kW h. Similarly, the aggregate peak demand reduces from 63 kW to 25 kW.

The inclusion of energy efficient lighting, leads to lower estimated peak demands and higher load factors. Because of the lower consumption, the subsidy costs for all the alternatives decrease, but the interruption costs are unaffected. The alternative most significantly affected by the change is standalone biomass. While the improvement in plant load factor improves the efficiency of power production, the reduction in demand leads to a reduction in the requirement for backup; in some cases, the backup generator is no longer required, reducing capital costs. The biomass alternative becomes much more competitive as a result, as shown in Table 8.

The two most sensitive parameters for these results will be the amount of rebound and the biomass fuel availability. Note that in this case, rebound in consumption should not be viewed as a bad thing because it implies that low income energy-limited rural consumers are able to increase consumption and experience greater utility. Biomass becomes less preferable as fuel availability decreases and as rebound increases. Table 9 captures this two-way sensitivity. With 50% rebound and low fuel availability, biomass is competitive with grid extension of 1 km or more only when grid supply is available for 2 h at peak and will become reliable only after 10 years.

An obvious barrier to large-scale adoption of energy efficient lights is the higher upfront cost relative to ICL. Over their lifetimes, CFLs are significantly less expensive. In fact, the payback period is 6–7 months (with a 15 W CFL costing Rs. 150–200 compared to Rs. 15 for a 60 W ICL), assuming a daily usage of 6 h. To encourage the replacement of incandescent bulbs with CFL, the government initiated a policy, Bachat Lamp Yojana ("Efficient Lighting Program"), under which households could purchase CFLs at the price of incandescent bulbs. The difference was to be financed using Clean Development Mechanism (CDM) fund. While the program eventually ran into trouble when the market for Certified Emission Ratings crashed, some of the states have reportedly achieved some success (Forbes India, 2012; Hindu Business Line, 2011). Previous attempts by some of the utilities could not be sustained due to the limited financial resources available to them

Table 9
Sensitivity of results for CFL lighting to fuel availability and rebound.

Zero Rebound		Years for reliable supply				
		2	4	6	8	10
Hours of supply	2			Biomass		
	3			For all fuel availability scenarios considered		
	4,5	Grid				

50% Rebound		Years for reliable supply				
		2	4	6	8	10
Hours of supply	2		Biomass		Low fuel	
	3	Grid				
	4,5				Base case fuel	

(CDM PoA document). LED lighting for residential purposes is still nascent, and its upfront costs are more than four times that of CFL lights and 40 times that of ICLs. Reportedly, the Delhi government is encouraging the adoption of LED lights by providing a 50% subsidy on upfront costs (The Economic Times, 2011, 2012).

Upfront capital subsidies have been the preferred approach (CDM PoA document), where the funding is from a centralized body and the utilities are not stretched financially. However, given the quick payback in the case of CFL, subsidies may not be necessary and the costs could be amortized over the course of a few months. For instance, utilities could replace CFL without any upfront fees and charge an extra Rs. 30–40/month for about 6 months. With similar usage, the electricity bills should reduce by about Rs. 20/month for each replaced lamp. Given the high mercury content, a mechanism for the safe disposal of used CFL bulbs must be put in place as well.

4. Policy implications

We began the paper with two questions—(1) when is conventional grid extension unadvisable for connecting unelectrified villages and (2) when is grid supply in electrified villages unreliable enough to look beyond the conventional route of supply? The best solution for a given village will depend on the nature of the demand in the village, the presence of local resources, the village economy, and incentives for and presence of micro-grid developers among many other factors. Broadly, we find that backing up unreliable grid with local DG based on biomass or diesel is an attractive strategy for a range of scenarios. Further, these results depend only on grid reliability and hold for both unelectrified and previously electrified villages. In the base case with conventional lighting, standalone DG plants do not seem to be optimal at distances within 17 km and this makes them appropriate only for small or remote villages. The analysis here does not account for fuel subsidies provided for kerosene and diesel. If these are included, the societal costs increase for unreliable supply (due to the kerosene subsidies for backup lighting), and for the diesel based routes. Standalone biomass DG plants, despite including a diesel generator as backup, become more competitive (becoming optimal at 6 km relative to 6 h grid supply).

With chronic supply shortage, residential energy efficiency holds great potential and strategies that promote the adoption of CFL lighting can reduce the costs of subsidy for all alternatives. The threshold for acceptability of unreliable grid supply reduces substantially when energy efficient lighting is incorporated- biomass standalone plants in particular become preferable to extending the grid over very short distances. For instance, the analysis recommends disconnecting an already electrified village from the 11 kV line and distribution transformer and replacing them with a standalone biomass plant for domestic supply, rather than continuing to provide the ‘poor’ grid supply described in Table 2.

The sizing of the alternatives in this analysis is based on a rigid demand target. In practice, meeting the demand in the peak hours, or perhaps even limiting it to the lighting demand, could still have immense value to the consumers. Conversely, subsidizing the purchase of solar lighting systems as backups for unreliable supply could be a promising approach. Solar home lighting systems (SLS) have small rooftop panels and batteries that can support 2–3 CFL (or increasingly, LED)) lights. These subsidies could take different forms- in general, it has been found that systems with high capital subsides are not maintained well.

While consumers may adopt short term augmenting from the market, it must be recognized that these markets are often very imperfect with high information asymmetry and the state must play a role in building awareness and protecting the consumers. In addition, the presence of these markets itself represents a failure of the state and the utilities in providing adequate service to their consumers. And hence, beyond the awareness building role above, the government must play a role in subsidizing such adoption. The interruption costs framework suggested in this paper could be useful in setting these subsidies.

Beyond the economic arguments made in this paper, two more fundamental considerations are relevant to providing reliable electric power in rural India. First, citizens of a modern democracy should enjoy a right to affordable and reliable electric power. In India at present there is no clearly defined right to “reasonable supply availability.” The goal of 6 h/day, which has become the present target for RE policies is still remarkably modest and means little if supply does not correspond to times of demand. Our analysis of different levels of availability in the peak 6 h period produced very different results. Second, affordable and reliable electric power is a prerequisite for much economic development. Electric power is an essential input if rural India is ever to rise above its present low standard of living, and grow a range of more modern commercial and light industrial activities. Rao (2013) suggests that household enterprise incomes in India increase not just with access to electricity, but improved electricity availability as well.

Institutional constraints to implementing and sustaining electrification projects, especially DG plants, present a major hurdle. Sustainable and replicable microgrid models, especially in terms of maintenance, continue to remain elusive and there is little standardization in this space. Because of the limited (but growing) number of active commercial microgrid developers in India, the scale and rate of implementation is a concern. The solar lighting systems market is relatively better equipped in this regard with the presence of a large number of companies as well as financial institutions with some experience in structuring loans. However, in both cases, targeted deployment of technical advice and resources from both the Center and from State Governments could considerably accelerate adoption.

One way to operationalize the central premise of interruption costs and confront the agency problem is through the development and enforcement of reliability indices that better reflect consumers and their end uses. Conventional metrics (such as CAIFI or SAIDI) are inadequate for monitoring unreliability of the magnitude present in rural India. A composite set of indices which reflect availability in times of high demand, day-on-day unpredictability, and number of consumers affected, with a focus on productive activities could help in setting up better targets and more comprehensive monitoring. In the event of the utilities being unable to meet these targets with central power procurement alone, appropriate penalties could create incentives for the utilities themselves to serve as an intermediary in diffusing and supporting the use of decentralized energy solutions.

A number of models that have been developed elsewhere around the world might be usefully adapted to the rural Indian setting. One example is a program called Efficiency Vermont, developed by the U.S. state of Vermont (see: www.efficiencyvermont.com). By adding a charge of 5–10 mills[2]/kW h, the state collects a fund that is then administered by a competitively selected non-profit entity to promote improvements in end-use efficiency and subsidize things such as more efficient lamps. In India, such a program might also subsidize solar lighting. Alternatively, State Electricity Boards, or local Indian utilities, might develop strategies to help consumers amortize the cost of compact fluorescents or solid-state lights through programs such as offering slightly lower rates for the first few kW h for a limited time to those consumers who participate in bulb replacement projects.

5. Conclusions

The principal implication of this study is that programs like the RGGVY have not solved the 'problem of rural electrification' because acute unreliability of supply continues to occur in much of rural India. While no single solution will be applicable everywhere in the country, some combination of better service standards (perhaps through the reliability indices discussed in the last section), energy efficient lighting, a willingness to support decentralized energy alternatives, and identifying scalable institutional models could be the way forward. Interestingly, abandoning its previous focus on unelectrified remote villages alone, MNRE's draft Remote Village Lighting policy proposes to support the use of local DG plants and solar lighting systems in electrified villages receiving less than 6 h of grid supply per day (Ministry of New and Renewable Energy (MNRE), 2012). This is certainly a step in the right direction.

In summary, the cost to India, and its rural citizens, of unreliable electric power is very high. The time has come for some new thinking about how to rectify this problem that, despite ambitious development goals, has continued to fester for decades.

Acknowledgments

This work was supported by academic and alumni funds from Carnegie Mellon University. We thank the editor and the two anonymous referees for their comments and suggestions.

Appendix A. Domestic end use assumptions

Average daily demand, controlling for reliability (using *Peak-Deficit*),

$$D_{daily} = \frac{D_{monthly}(Tariff, PropTV)}{30} \tag{A1.1}$$

where $D_{monthly}$ is the estimated average monthly demand and is a function of *Tariff* and *PropTV*. Naturally, the sum of hourly demands d_h will be equal to the daily demand, (Table A1.1)

Table A1.1
Community load assumptions.

	Load (*W*)	Time of operation
Streetlights (per light)	100	6 PM–7AM
School	600	10 AM–4 PM
Drinking water pump	2238 (or 5 HP)	2 AM–4 AM

$$\sum_{h=1}^{24} d_h = D_{daily} \tag{A1.2}$$

There are two primary applications-lighting and television, with lighting being the more basic demand. After a threshold lighting demand is met, the TV is assumed to be purchased and used. Once lighting and TV loads are met in the peak demand period, electricity usage in the morning and afternoon hours is assumed to increase (Table A3.1 and A3.2).

The average lighting load in the peak hours (which in this study, will be assumed to comprise 6 h/day—early mornings 5–7 AM and evenings 6–10 PM) are estimated as below.

$$lighting_{h \in peak} = \frac{D_{daily}}{6} \text{ if}, D_{daily} < 6L \; = L \text{ otherwise} \tag{A1.3}$$

where L is the maximum hourly electricity consumption on lighting in the six peak demand hours. It is assumed that incandescent bulbs are used for lighting. Similarly, the average load in the four evening hours (6–10 PM) due to TV usage is estimated as,

$$\begin{aligned} tv_{h \in evening} &= \frac{(D_{daily} - lighting_{h \in peak})}{4} \text{ if}(D_{daily} - lighting_{h \in peak}) < 4TV \\ &\quad \times PropTV \\ &= TV \times PropTV, \text{ otherwise} \end{aligned} \tag{A1.4}$$

TV is the assumed maximum hourly household *TV* consumption. Residual hourly demand distributed uniformly through the day (except for nighttime) will then be,

$$any_{h \in night}' = \frac{D_{daily} - (6lighting_{h \in peak} + 4tv_{h \in evening})}{(17)} \tag{A1.5}$$

To be clear,

$$d_h = lighting_h + tv_h + any_h \tag{A1.6}$$

Average household load profiles were estimated using the approach above and assumptions listed in Table 2. The load assumptions for community level facilities are summarized in Table A1.1.

Appendix B. Plant sizing

Required plant size (for biomass and diesel DG) or transformer rating should be,

$$C = \frac{\max(D_h^{agg})}{pf \times (1 - loss_{dist})} \tag{A2.1}$$

where D_h^{agg} is the aggregate load at hour h, pf is the power factor, and $loss_{dist}$ is the distribution loss in the local network.

In the case of solar, sizing is slightly different because of the need for battery storage. Assuming all supply is through stored energy, the required plant and battery capacities are sized as follows (following Chaurey and Kandpal (2010)).

[2] 1 mill is one-tenth of a cent.

Table A3.1
Cost inputs and assumptions for the different alternatives.

	Equipment	Capital cost (in Rs.)	Annual O&M costs (fraction of capital costs)	Lifetime (years)	References
	LT line (per km)	190,000	0.03	20	Bangalore Electricity Supply Company (2010-Schedule of costs)
Grid extension	11 kV line (per km)	210,000	0.03	20	
	Transformers (in kVA)				
	25	87,000	0.03	20	
	63	117,000			
	100	153,000			
Biomass Gasification	Gasifier (per kW)	25,000	0.05	10	Nouni et al. (2007)
	Engine (per kW)	30,000	0.05	20	Banerjee (2006)
	Civil works	72,000+9000* (Capacity)	0.02	20	(Ministry of New and Renewable Energy (MNRE) (2008)-VESP guidelines)
Solar PV	PV panel (per kW)	80,000	0.02	20	Aanesen et al. (2012) Nouni et al. (2006)
	Battery (per 12 V–200 Ah battery)	22,000	0.02	10	Chaurey and Kandpal (2010)
	Power conditioning unit (per kW)	40,000	0.02	20	Ministry of New and Renewable Energy (MNRE), 2010
Diesel	Generator (per kW)	20,000	0.1	20	Nouni et al. (2007)

Table A3.2
Summary of inputs for costs, efficiencies and other operational variables.

	Length of the LT line	2 km	Assumption
	Local distribution loss	5%	Assumption
	Power Factor	0.95	Assumption
Grid extension	Cost of power purchased (Rs./kW h)	2.5 (2-3)	Parameter
	Technical and commercial losses	20% (15–30%)	Parameter
Biomass gasification	Cost of biomass fuel (Rs./kg)	1.5 (1–3)	Parameter
	Number of working days	300 (200–360)	Parameter
	Load factor	Fuel efficiency (kg/kW h)	Nouni et al. (2007)
	0	0	
	50%	1.68	
	75%	1.54	
	100%	1.40	
Solar PV	Energy loss due to ambient temperature	0.1	Chaurey and Kandpal (2010)
	Energy loss due to dust	0.03	
	Energy loss due to mismatch among solar cells	0.02	
	Inverter efficiency	0.98	
	Battery efficiency	0.8	
	Charge controller efficiency	0.9	
	Effective hours of full sunshine (per day)	5.5 (4.5–6)	Parameter
	Number of working days	300 (250–320)	Parameter
	Terminal Voltage	120 V	Chaurey and Kandpal (2010)
	Maximum Depth of Discharge	0.7	Input
Diesel	Diesel fuel cost (Rs./l)	40	Ministry of Petroleum and Natural Gas (2013)
	Fuel efficiency (l/kW h)	0.3	Nouni et al. (2007)

$$C_{solar} = \frac{\sum_{h=1}^{24} D_h^{agg}}{pf \times (1-loss_{dist}) \times \eta_{inverter} \times \eta_{battery} \times \eta_{cc} \times (1-f_{temp}) \times (1-f_{dust}) \times (1-f_{mismatch}) \times EHFS} \tag{A2.2}$$

where $\eta_{inverter}$, $\eta_{battery}$, and η_{CC} are the efficiencies of the inverter, battery, and charge controller f_{temp}, f_{dust} and $f_{mismatch}$ are the losses associated with ambient temperature, dust, and mismatch among cells.

EHFS is the expected hours of full sunshine—the level of solar radiation is translated in terms of hours of full sunshine that provides 1 kW/m^2.

$$C_{solar-battery} = \frac{\sum_{h=1}^{24} D_h^{agg}}{pf \times (1-loss_{dist}) \times \eta_{inverter} \times \eta_{battery} \times M_{DoD} \times V} \tag{A2.3}$$

where M_{DoD} is the maximum depth of discharge and V is the terminal voltage

Appendix C. Capital and operations costs

Cost of grid supply is estimated as power purchase costs inflated by the reciprocal of (1—transmission and distribution losses).

The fuel costs for the biomass plant will be,

$$x_{fuel,\,t}^{Biomass\ DG} = \sum_{h=1}^{24} [\eta_{biomass}(d_{h,t}, C_{biomass}) \times p_{biomass} \times d_{h,t} \times days_{operating}^{biomass} + \eta_{diesel}(d_{h,t}, C_{diesel}) \times p_{diesel} \times d_{h,t} \times (365 - days_{operating}^{biomass})] \tag{A3.1}$$

where $\eta_{biomass}$ and η_{diesel} are the fuel efficiencies of the biomass and diesel generators and are functions of load factors ($d_{h,t}/C_{biomass}$ or $d_{h,t}/C_{diesel}$), $C_{biomass}$ and C_{diesel} are the installed capacity of the generators, $p_{biomass}$ and p_{diesel} are the fuel prices of biomass and diesel, and $days^{biomass}_{operating}$ are the number of operating days of the biomass generator.

The cost of the backup diesel fuel will be,

$$x^{Solar}_{fuel,\,t} = \sum_{h=1}^{24} \eta_{diesel}(d_{h,t}, C_{diesel}) \times p_{diesel} \times d_{h,t} \times (365 - days^{solar}_{operating}) \quad \text{(A3.2)}$$

Table A3.1 and A3.2 list all the cost inputs and assumptions for each of the alternatives.

References

Aanesen, A., Heck, S., Pinner, D., 2012. Solar Power: Darkest before Dawn. M.c.Kinsey on Sustainability and Resource Productivity. McKinsey and Company.

Azevedo, I.M.L., Morgan, M.G., Lave, L., 2010. Residential and regional electricity consumption in the US and EU: how much will higher prices reduce CO_2 emissions? Electr. J. 24 (1).

Banerjee, R., 2006. Comparison of options for distributed generation in India. Energy Policy 34, 101–111.

Bangalore Electricity Supply Company (BESCOM), Cost data sheet 2010-11.

Census of India, 2011. Source of Lighting: 2001–2011. Available online on ⟨http://www.censusindia.gov.in/2011census/hlo/Data_sheet/Source%20of%20Lighting.pdf⟩ (last accessed on August 20, 2012).

Chaurey, A., Kandpal, T.C., 2010. A techno-economic comparison of rural electrification based on solar home systems and PV microgrids. Energy Policy 38, 3118–3129.

Cust, J., Singh, A., Neuhoff, K., 2007. Rural Electrification in India: Economic and Institutional Aspects of Renewables EPRG 0730 and CWPE. 0763.

Ekholm, T., Krey, V., Pachauri, S., Riahi, K., 2010. Determinants of household energy consumption in India. Energy Policy 38, 5696–5707.

Fillipini, M., Pachauri, S., 2004. Elasticities of electricity demand in urban Indian households. Energy Policy 32, 429–436.

Gundimeda, H., Kohlin, G., 2008. Fuel demand elasticities for energy and environmental policies: Indian sample survey evidence. Energy Econ. 30, 517–546.

IAEA, 1984. Expansion Planning for Electrical Generating Systems—A Guidebook. Technical Reports Series No. 241.

Kanase-Patil, A.B., Saini, R.P., Sharma, M.P., 2010. Integrated renewable energy systems for off grid rural electrification of remote area. Renewable Energy 35, 1342–1349.

Lawton, L., Sullivan, M., van Liere, K., Katz, A., Eto, J., 2003. A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys. Ernest Orlando Lawrence Berkeley National Laboratory, Environmental Energy Technology Division, LBNL-54365.

Mills, E., 2003. Technical and Economic Performance Analysis of Kerosene Lamps and Alternative Approaches to Illumination in Developing Countries. Lawrence Berkeley National Laboratory.

Ministry of New and Renewable Energy (MNRE), 2008. Implementation of Village Energy Security Test Projects during 2008–2009 and 2009–2010, Sanction reg. No. 51/2/2007-08/VESP. Government of India.

Ministry of New and Renewable Energy (MNRE), 2010. Guidelines for Off-Grid and Decentralized Solar Application, ⟨http://mnre.gov.in/file-manager/UserFiles/jnnsm_g170610.pdf⟩ (accessed on April 30, 2012). Government of India.

Ministry of New and Renewable Energy (MNRE), 2012. Village Lighting Programme (Draft). Government of India 13/14/2011-12/RVE.

Ministry of Petroleum and Natural Gas, 2013. Price Build-up of Sensitive Products. Petroleum Planning and Analysis Cell. Government of India. Available on ⟨http://ppac.org.in/writereaddata/Price%20Build%20up%20Sensitive%20Products.pdf⟩ (last accessed on August 2, 2013).

Ministry of Power (MOP), 2006. Resolution-Rural Electrification Policy. No.44/25/5-RE (Vol II).

Ministry of Power (MOP), Website Summarizing RGGVY Progress, ⟨http://rggvy.gov.in/rggvy/rggvyportal/plgsheet_frame3.jsp⟩, (accessed on January 2, 2012a Government of India).

Ministry of Power (MOP), Project Reports, Accessible Through ⟨http://rggvy.gov.in/rggvy/rggvyportal/covered_frame.jsp⟩, (accessed on January 2, 2012b Government of India).

Munasinghe, M., Gellerson, M., 1979. Economic criteria for optimizing power sector reliability levels. Bell J. Econ. 10 (1), 353–365 (1979).

Munasinghe, M., 1988. The Economics of rural electrification projects. Energy Econ. (January 1988).

Nouni, M.R., Mullick, S.C., Kandpal, T.C., 2006. Photovoltaic projects for decentralized power supply in India: a financial evaluation. Energy Policy 34, 3727–3738.

Nouni, M.R., Mullick, S.C., Kandpal, T.C., 2007. Biomass gasifier projects for decentralized power supply in India: a financial evaluation. Energy Policy 35, 1373–1385.

Nouni, M.R., Mullick, S.C., Kandpal, T.C., 2009. Providing electricity access to remote areas in India: niche areas for decentralized electricity supply. Renewable Energy 34, 430–434.

Oda, H., Tsujita, Y., 2011. The determinants of rural electrification: the case study of Bihar in India. Energy Policy 29 (6).

Prayas Energy Group, 2011. Rajiv Gandhi Rural Electrification Program: Urgent Need for Mid-course Correction. Discussion Paper, Accessible online on ⟨http://www.prayaspune.org/peg/publications/item/162-rajiv-gandhi-rural-electrification-program-urgent-need-for-mid-course-correction.html⟩.

Rao, N.D., 2013. Does (better) electricity supply increase household enterprise income in India? Energy Policy 57, 532–541.

Reddy, A.K.N., Reddy, B.S., 1994. Substitution of energy carriers for cooking in Bangalore. Energy 19 (5), 561–571.

Sarkar, A., 1996. Reliability evaluation of a generation-resource plan using customer outage costs in India. Energy 21 (9), 795–803.

Sinha, C.S., Kandpal, T.C., 1991. Decentralized v grid electricity for rural India—the economic factors. Energy Policy (June 1991).

Tiwari, P., 2000. Architectural, demographic and economic causes of electricity consumption in Bombay. J. Policy Model. 22 (1), 81–98.

Udupa, A., Kumar,R., Ram, M., Harish, S., 2011. Failed Aspiration: an Inside view of the RGGVY. Greenpeace Report, Available online on ⟨http://www.greenpeace.org/india/Global/india/report/RGGVY%20national%20report.pdf⟩, (accessed on January 2, 2012).

van den Broek, R., Lemmens, L., 1997. Rural electrification in Tanzania—constructive use of project appraisal. Energy Policy 25 (1), 43–54.

Woo, C.K., Pupp, R.L., 1992. Costs of service disruptions to electricity consumers. Energy 17 (2), 109–126.

World Bank, 2008. The Welfare Impact of Rural Electrification: A Reassessment of Costs and Benefits. Independent Evaluation Group.

Web references

Forbes India, 2012. CFL Bulbs Dim out in Delhi. ⟨http://forbesindia.com/article/numerix/cfl-bulbs-dim-out-in-delhi/32416/1⟩ (accessed on 4 September 2012).

Hindu Business Line, 2011.Kerala, Karnataka Roll out CFL Scheme. ⟨http://www.thehindubusinessline.com/industry-and-economy/article2201639.ece⟩ (accessed on 4 September 2012).

The Economic Times, 2011. Prices of LED Lamps and Luminaires Halve over Last 9 months. ⟨http://articles.economictimes.indiatimes.com/2011-07-19/news/29790897_1_cfls-leds-lamps⟩ (accessed on September 4, 2012).

The Economic Times, 2012. LED Bulbs to be Sold in the City at Half the Market Price. ⟨http://articles.economictimes.indiatimes.com/2012-07-20/news/32764525_1_cfl-bulbs-ordinary-bulbs-compact-fluorescent-lamp⟩ (accessed on September 4 2012).