Peak Generation Tariff: Managing the Power System

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Introduction
The problems of the power sector never seem to abate. Even after two decades of reform, which include legislative reforms to encourage competition, the crisis in the sector persists and availability of power continues to be a major impediment for economic growth and development. Persistent issues in acquiring land, getting environmental clearances, fuel availability, inadequate power evacuation facility, and poor financial health of the distribution companies are the key hindrances faced by the power sector investors. Challenges notwithstanding, fixated focus on generation capacity addition, particularly over the last plan period, has accentuated the crisis. Estimates show that while about 45,590 MWs of coal and gas-based generation capacities were added in 2007-12, inadequate supply of domestic fuel and inability to pass through expensive imported fuel have resulted in stranded capacity of about 33,000 MWs (KPMG 2013). The resultant financial stress is heavily experienced by the developers and lenders. On the other hand the cost of unserved energy and load, as evidenced from energy and peak load deficits, continue to remain very high resulting in a huge loss to the economy. In this scenario of unmet peak demand, while useful generation capacity remains stranded for want of adequate fuel, this note explores the option and preconditions of using differential peak generation tariff to facilitate utilisation of stranded capacity, and also encourage realisation of untapped hydro potential and manage power system better.

Large generating capacity build up, but high demand deficit persist
The power generation capacity has grown significantly over the years (see Figure 1), of about 5% between 9th and 11th Plans and 8.6% over the 11th Plan, with a present installed capacity of more than 227 GWs (as of August 2013).

![Figure 1: Installed Generating Capacity (MW)](image)

Sources: CEA (2013a; 2013b)
Although generation capacity build-up significantly fell short of targets till the 10th Plan, with a tremendous thrust over the 11th Plan the achievements fell short of the targets by just 11.9% compared to 48.5% in the 10th Plan (see Figure 2).
However, despite such huge capacity additions over the years, with installed capacity of about 199.8 GWs and 223.3 GWs in 2012 and 2013 respectively, significant energy and peak demand deficits persist in the system. The peak demand for 2011-12 was 130 GWs and in 2012-13 was about 135 GWs, while average load was about 107 GWs and 114 GWs respectively in these years. It is an irony that the unmet peak demand and energy in 2011-12 were 10.6% and 8.5% and in 2012-13 these deficits were 9% and 8.7% respectively (see Figure 3(a) and 3(b)), despite the installed capacity being 55-65% higher than the peak demand for these years.

Sources: CEA & CII (2007); CEA (2012a)
Considerable seasonal variations in energy and peak demand, and the demand deficits (see Figures 4(a) and 4(b)), are also experienced, despite having a mix of generation technologies operating to meet the demand.

Source: CEA (2013a)

Source: CEA LGB Report (2013-14)
Rationale for high unmet electricity demand

Interplay of several factors are responsible for the persistent high electricity demand, both peak and energy, which include non-adherence to theoretical planning for supply system and the resultant National Electricity Plan (NEP), non-availability of fuel, incomplete integration of national grid, poor financial health of distribution utilities hindering their ability to procure expensive power, and the associated unrestrained practice of restriction and curtailment policy by the distribution utilities at the cost of unserved energy and load.

Demand for electricity varies by the time-of-day and also by season. Thus, supply side planning to meet the demand entails forecasting hourly demand and conjuring annual load duration curves (LDCs) for the planning period and arriving at annual capacity addition of portfolio of supply technologies to meet the LDCs at optimal cost with a specified degree of reliability (Loss of Load Probability) and redundancy. Since electricity could be generated using conventional and non-conventional fuels and with different technologies, the combination of fuel and technology involves trade-off between fixed and variable costs. Also, the technology and fuel combinations allow different levels of flexibility in backing down or ramping up generation at short notice without compromising on the efficiency. Thus, generation technologies using conventional fuels could be broadly classified as those which are more suited to meet round-the-clock demand, because of their high fixed cost and relatively low variable (fuel) costs and also due to the difficulty of easily backing down such technologies. Thermal plants using coal, lignite and nuclear are considered as backstop technologies most suited to meet the round-the-clock base load. The economics arising from higher efficiency in gas-based combined cycle technology also makes them a candidate for meeting base load and also intermediate load (between base and peak load). Storage-based hydro plants of greater than 25 MWs have the maximum flexibility and cost effectiveness to meet the peak load as well as the intermediate load. Hydro plants are also suited for meeting the base load in extremely good monsoon years besides facilitating maintenance of base load thermal plants during the monsoon seasons and other times when required. Peak load which is reached for few hours during the day and the evening, and higher load achieved during some of the seasons, are best met with technologies having maximum flexibility besides having fixed and variable cost combinations that allow their economics to best cater to such fewer hours of operation. Thus, gas-based plants having project costs relatively lower than base load plants, while having fuel costs or variable costs higher, and having the flexibility to quickly back-down or ramp-up are most suited to meet peak load. Renewable energy technologies are seasonal and intermittent in nature and are often treated as must run based on their availability, more so because of their environmental positives. The NEP, as well as the planning that the Central Electricity Authority (CEA) has always been undertaking, considered this detailed techno-economic procedure. However, the actual capacity additions and supply side build-up for decades now have failed to comply with the optimal build-up charted out in the detailed plans.

Hydro capacity additions have for long suffered due to challenges in land acquisition, environment and forest clearances, infrastructure bottlenecks and social activism. After the initial couple of decades since independence, storage type hydro power plant build-up slowed down (see Figure 5) and the decline of its share in total installed capacity has been steady (see Figure 6). In 2013, the share of hydro has declined to 17.3% from about 25% a decade earlier, and this has compromised the ability of the supply system to cater to the variations in load. The unutilised hydro potential is huge (see Figures 7(a) & 7(b)), particularly in the north-eastern (93.1%) and northern region (58.8%). Utilisation of this could significantly meet the peak and energy requirements.
Figure 5: Installed Generation Capacity

Source: CEA (2013a)

Figure 6: Share of Hydro, Coal & Gas in Installed Generating Capacity

Source: CEA (2013a)

Figure 7(a): Basin-wise Status of Hydro Electric Potential Development (in terms of Installed Capacity above 25 MW) (as on 30.06.2013)

Source: CEA (2013a)
Excessive thrust on thermal capacity additions, particularly over the last decade, has skewed the supply side suited for meeting a relatively flatter LDC. In fact, the focus has been more on building coal thermal plants and combined cycle gas plants. This is not only technically inappropriate for meeting peak load, but also more expensive for meeting the same as it would either entail over-building the supply system or force the distribution companies to manage peaking periods through load curtailment policies.

More than 58% of the total installed capacity is coal based, which demands huge quantum of coal for generation. Coal-based power plants till a few years back used to achieve very high levels of utilisation, as domestic coal, although of poor quality, was available in plentiful. However, despite having huge reserves of coal, production of coal failed to keep pace with the demand arising from the huge coal-based capacity build-up. The situation has worsened over the last Plan period as domestic production has considerably fallen short of requirement. Use of imported coal to make up the shortfall is expensive and also vulnerable to international price and supply fluctuations. Moreover, inability of the distribution utilities to pay for expensive power as well as technological constraints to use imported coal beyond a specified percent has added to the woes of the generators. Thus, generating companies faced with huge coal supply shortage are now operating at low plant load factors (PLFs) despite overall generation increasing. Coal-based generation at 585 billion units (BU) increased by 15% in 2012-13 over 2011-12; however PLF declined to 69.7% from 74% during the same period. The PLF has further declined to 63.9% during the period April-September 2013. The generation loss due to coal shortage was about 12.3 BU in 2012-13 (see Figure 8).

Sources: CEA OPMD Reports (various years)
The situation is far worse for the gas-based generating plants as gas shortage has grown to damaging proportions (see Figure 9). While significant gas-based capacity has been added since the KG D-6 gas finds, the production from this source has been on the decline and large capacity is idling for want of gas. The KG D-6 basin, housing the largest gas reserves in India, which peaked in terms of natural gas production at 62 million standard cubic metres per day (MSCMD) in March 2010, has since been declining, having produced only 17 MSCMD in March 2013. Of the total 20,381 MW of gas-based plants, about 14,029 MW of capacity is dependent on KG basin gas.

![Figure 9: Requirement and Availability of Gas (MMSCMD) and Shortfall (%)](image)

Source: CEA (2012b)

The supply of KG D-6 gas to power sector has been zero since March 2013. About 2,979 MW capacity which runs exclusively on KG D-6 is lying idle, while about 11,050 MW are running at very low PLF as it is receiving only APM gas while getting no supply from KG D-6. Generation loss due to shortage of gas availability was about 73 BU in 2012-13, and was about 51 BU in the April-September 2013 period. Presently installed gas-based capacity operating at a low PLF of about 25% is stranded for want of gas (see Figure 10).

![Figure 10: Generation Loss and PLF of Gas Power Plants](image)

Sources: CEA OPMD Reports (various years)

Note: Data for Generation Loss for 2012-13 is till February.

The fixed cost of coal-based plants are about Rs. 1.4/Kwh when operating at say 80% PLF, but if it were to operate at 20% PLF to cater to just the peak load then the fixed cost would shoot up to about Rs. 5.6/Kwh making it completely unviable. Gas-based capacity, stranded for want of gas, are not even able to recover their fixed costs as distribution utilities are not willing to off-take
expensive power if r-LNG is used (declaring these power plants as non-available with domestic gas). Thus, both energy and peak demand remains unmet, while the cash strapped and huge loss making distribution utilities freely curtail and restrict consumer load.

The unmet demand is accentuated due to incomplete integration of the national grid. While the northern grid with very high peak demand is connected with the east, west and north-east grids, and is able to manage its demand situation through regional exchange, the southern region is not able to manage its demand situation well (see Figure 11). Also, congestion data from the power exchanges show the difficulty of managing the demand-supply situation due to inadequacy of evacuation facility particularly during peak demand months (see Figure 12).

![Figure 11: Peak Load - Northern & Southern Regions (2007-08 to 2012-13)](image)

Sources: CEA LGB Reports (various years)

![Figure 12: Percentage of Time Congestion occurred during the month](image)

Sources: CERC (various monthly reports)

**Peak Generation Tariff to Meet Demand and Utilise Precious Resources**

It is indeed a matter of concern that with so much hydro potential in the north and north-east remains unutilized, when the northern peak demand is very high. It is also a matter of shame that huge gas-based capacity is sitting stranded and idle in the southern region, when the region is facing huge peak deficits with the grid not connected to NEW grid. Gas-based power plants and hydro plants are techno-economically best suited to meet the peak demand. Gas-based plants faced with domestic fuel shortage have to use imported r-LNG, which makes the tariffs about Rs. 10-11/Kwh.
and also vulnerable to exchange rate fluctuations. Even with revised domestic prices, the tariffs for gas-based plants would be about Rs. 5-6/Kwh. The distribution utilities going through financial distress are not comfortable to procure such expensive power, even to meet peak demand for a short period, since presently the legislation and policies do not mandate them to meet peak demand and there is no formal provision for differential peak and off-peak tariffs. By allowing for higher peak tariff for peaking generation, it would help salvage the stranded capacity operating at very low PLF to meet the peak demand. If distribution utilities look at gas-based generation for meeting peak demand and not for meeting round-the-clock demand, then procurement of gas-based power using imported or high cost fuel may be more acceptable. Peaking tariffs would also encourage developers to undertake peaking hydro power plants, and this in turn would once again improve the hydro-thermal balance in the system.

Transactions in the short-term market have increased over the last 5 years, with the share of bilateral trade and through the exchange in total generation increasing from 4% to 7%. The short-term market is gradually maturing with the diversity of day ahead and forward market products, and newer products being introduced. Transactions are already prevalent for time-of-day products - peak, off-peak and round-the-clock, and for these products differential prices are attained. As is evident from Figures 13(a) and 13(b) below, bilateral transactions are attained at a higher price than the clearing prices on the exchange, particularly the peak load transactions.

![Figure 13(a): Price of Electricity Transacted through Traders for Time-of-Day Products (Rs. / kWh)](image1)

![Figure 13(b): Weighted Average of Price of Electricity Transacted through Power Exchanges (Rs. / kWh)](image2)

*Sources: CERC (various monthly reports)*

There is already a market for peak power supply and there is also a willingness to pay a higher price for the same. It can be seen from Figures 14(a) and 14(b) that the prices and volume of transactions vary by the seasons, and are higher for peaking seasons. The clearing price in peak period at about
Rs. 6/Kwh is comparable to gas-based generation with most transactions happening in the Rs. 4-6/Kwh range, and the maximum prices attained for short-term purchases are several times higher. The two peaking seasons - hot and sultry summer months, and the dry winter months - demand greater short-term power and the clearing prices are accordingly discovered. However, prices of transactions in the April-November months are higher, and in these months slightly better supply from hydro stations are available. The financially constrained distribution utilities free to restrict and curtail load, are better able to manage the peak load in the April-November months than the winter months as is evident from the monthly peaking deficits. The volume of transactions in the short-term markets during the peak period is barely 0.79% and is a high 93.24% for round-the-clock transactions. Even for transactions over the exchange, the volume of transactions during the peak period is low and prices higher compared to the other-than-peak periods. Further, the prices of electricity transacted over similar periods in the southern regions are higher than those over the NEW grid. This is due to the dual impact of grid congestion and incomplete integration with the NEW grid. This also gives all the more reason for utilising the stranded gas capacities in the southern region for efficient utilisation of resources.

Figure 14(a): Average and Peak Period Prices of Electricity Transacted and Peak Demand (2012-13)

Figure 14(b): Average and Peak Period Prices of Electricity Transacted and Peak Deficit (2012-13)

Sources: CERC (various monthly reports)

This also clearly demonstrates that in the present legislative and policy framework there is no urgency to meet the peak demand. There is willingness to pay a higher generation tariff on the part of distribution utilities to the extent that they are able to pass it on to the consumers. A recent positive development is that the distribution utilities in almost all the States have gone for tariff
revision in recent years to reduce the gap and improve cost recovery (i.e. 23 States and 5 Union Territories have gone for tariff revision in FY13 and 8 States have increased their tariffs till August this year) (ibid). The financial losses of distribution utilities continue to remain very high, and this restricts their ability to procure expensive power even for a short duration. Consumers on the other hand faced with the supply crisis, particularly for their peaking requirements - seasonal or time-of-day, are forced to meet the deficits through self-generation using diesel fuel or battery invertors, both of which are extremely expensive and involves cost of about Rs. 15-16/Kwh. Estimates indicate that cost of power deficit in the form of additional cost of diesel back-up generation is Rs. 43,800 crores annually (ibid).

In view of the large variations in seasonal demand, high demand during some of the months and regional differences, it is rational to utilise the stranded gas capacities faced with limited gas supply, high and volatile imported gas prices, exposed to foreign exchange risks and forced to operate at extremely low PLFs. This could be possible if a separate peak generation tariff is offered to cover their fixed costs at low PLFs and high fuel costs. Since the overall power purchase costs of the distribution utilities would be impacted more for round-the-clock purchases from gas plants, the impact may not be that high for short duration but assured procurement from the gas capacities. The 2,000 MW plants stranded in the southern region could well cater to the southern grid not having the privilege of drawing upon redundant power supply in the NEW grid. Although mainly hydro and some gas generation are already participating in the short-term market, the volume is still quite low and a differential time-of-day generation tariff can facilitate greater participation of the generators.

Concluding Comments

The stylised facts presented above put forth a strong case for introducing peak generation tariffs, and formalising the same through its inclusion in the legislative and policy framework. The Ministry of Power (MoP) recognising its importance is already working on a peaking power policy for gas that will encourage power distribution companies to invite bids from generation utilities for meeting power shortages during peak consumption hours - normally between 8 AM and 11 AM, and 6.30 PM and 10 PM (Bhaskar 2013). MoP should urgently finalise the policy to salvage the crisis faced by large number of gas-based installed capacities and also encourage new capacity additions of peaking stations. MoP should also take up with eGOM the issue of prioritising the Gas Utilisation Policy to prioritise allotment of gas to new peaking plants.

Effort to promote peaking plants, encourage better hydro-thermal balance and meeting peak demand would be unsuccessful unless the distribution entities are made accountable towards meeting the peak demand. Of course, consumers also voice dissent for any tariff increase even if it involves providing reliable supply by the distribution utilities. Consumer’s action defeat rationality when they oppose assured supply at a higher tariff while not hesitating to incur a high cost to arrange for their own supply back-up. There is also the issue that the generation system is already over-built but not rationally built. With such huge investments already locked-in, which is ideally attuned to meeting base load but presently utilized for also meeting peak load, it is not possible to designate peaking stations from the existing capacity. Thus, policy should provide for better utilisation of existing capacity to meet the peak and off-peak load requirement of consumers, and also pave the way for building a more rational and efficient generation system. Clearly the regulators and the government have to play a very important role in planning and delivery of assured supply at optimal cost to all the stakeholders.

The government and regulators have to recognise the costs of not meeting the peak load - to the consumers and the economy - and ensure that the distribution utilities do not use the load restriction and curtailment policies for balancing their own precarious financial situation at the expense of the consumers. Thus to begin with policies and regulations should mandate that the distribution utilities cannot shed load in uninformed but has to follow a pre-specified and regulator approved load shedding schedule, and for the duration of the load shedding the distribution utilities have to forego the cross-subsidy surcharge from the consumers. The regulator by specifying time-of-
day tariff for consumers allows the distribution utilities to follow the competitive bidding route to procure power during peak period at a higher price. Since it may take a while for the market to develop for peaking generation, it would be critical for the regulators to proclaim regulations for time-of-day tariffs, particularly peak period tariffs for generation, to facilitate market development and efficient utilisation of valuable resources. The implementation of TOD tariff and its efficacy would critically depend on TOD metering at the consumer end. In the absence of metering for all customers it is important undertake load studies for customer segments to arrive at the appropriate tariff schedule. Thus, all efforts should be channelised in implementing and utilising peaking power and not just restricting it to the planning stage, and introducing peaking generation tariffs at a rate that is attractive and higher than other-than-peak period tariffs to facilitate implementation.
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