The Price of Plenty

Insights from ‘surplus’ power in Indian States

Prayas (Energy Group)

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March 2017

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Summary

For the first time in decades, India is likely to be power 'surplus'. This is an important step on the road to access, even though universal supply of uninterrupted, quality power still remains a challenge. Surplus power today implies backing down, which has significant impacts on the Distribution Company (DISCOM) finances and operations as well as consumer tariffs. This is due to the nature of take-or-pay, two-part payment contracts, and lack of avenues or adequate efforts for sale of 'surplus' power. The impacts are much more severe in some states, where about 15% to 30% of the capacity is backed down annually.

This report focuses on insights from states which are experiencing sustained surplus to highlight important lessons at the national level. This includes Gujarat, Maharashtra, Madhya Pradesh, Andhra Pradesh, Telangana, Haryana and Punjab. Tracing the major trends across states, it is evident that coal-based capacity accounts for most of the capacity being backed down. Within this, capacity owned by the state generating companies accounts for a majority of the capacity being backed down due to its high variable costs. Additionally, some of the newly commissioned plants are also being backed down for the same reason. Another trend observed, is that surplus power does not necessarily imply elimination of shortages. Seasonal variations often result in DISCOMs facing acute shortages and facing surplus in the same year.

At times, sales migration due to open access and captive options has been cited as reasons for the increasing surplus in many states. But, evidence from various states shows that open access accounts for only about 10% to 25% of the total capacity backed down. Though the demand growth in recent years has been moderate, the variation between projected demand and actual demand is significant, highlighting the fact that one of the key drivers of surplus capacity is capacity addition based on overestimation of demand. Most states rely on estimates from the Electric Power Survey (EPS), published by the Central Electricity Authority (CEA) to project demand. For decades, EPS projections have been known to overestimate demand. Further, the EPS forecasts demand for the entire state (excluding captive consumption), not just the distribution companies in the state. With growing avenues such as open access and multiple options for captive generation, this distinction has become more important. DISCOMs often also deviate from these estimates and forecast higher demand by assuming an increased demand to meet the universal access goal, or by projecting higher industrial growth in the state.

Coupled with these issues about demand estimation, during the 11th and 12th plan period, there was a large-scale capacity addition, which has resulted in the current surplus. In many states, the overestimated demand forecasts along with projected availability of capacity was used to estimate future power deficit and thus justified the capacity which needed to be procured. Even though some DISCOMs recognised that there are seasonal variations in demand, most power that was contracted was plain vanilla base load generation capacity for 25 year periods. DISCOMs also planned for new capacity to compensate for the possibility of delays in execution and cancellation of projects. In the medium-term, the commissioning of the delayed and new capacity would further contribute to the surplus. In some cases, even in the face of surplus, DISCOMs procured capacity in anticipation of high demand growth and future shortages.

Thus, due to the capacity in pipeline, and given increased sales migration and falling prices of renewable energy, the magnitude of surplus power in the medium-term will also be significant. This will be further exacerbated if states meet only a part (say 60%) of the commitment required to meet the national target of renewable capacity addition by 2022. Therefore, surplus is not a transient phenomenon. States will need to devise effective ways to avoid future increase in surplus and to manage existing surplus. In order to avoid future surplus, states should invest in regular, more frequent, and scientific power procurement planning processes. Further, such demand forecasting and capacity planning exercises by the DISCOMs should involve a consultative, regular process which reviews the status of capacity in the pipeline, weeds outs inordinately delayed projects and assesses factors in changing trends in demand. This is imperative to avoid the unfavourable situation of sustained, large, idle surplus capacity. In fact, any new capacity should only be contracted after such a process is followed in letter and spirit.

To manage existing surplus many states are currently selling power in the short-term markets. Electricity Regulatory Commissions (ERCs), often project surplus based on estimations of availability and assume the sale of such surplus power at a pre-determined rate. The projected revenue from this sale is used to reduce power purchase costs and thus offset revenue gaps. However, most DISCOMs end up incurring losses on this account as they are unable to generate the assumed revenues from sale of power. In some cases this is because the projected availability was not achieved or because the high rate of sale could not be realised. This results in losses or increase in future tariffs via true-ups. If a realistic surplus is projected for sale at probable prices, the ERCs can nudge DISCOMs to explore more avenues for sale of this power.

Across states, the average variable costs of coal-based plants which are backed down significantly ranges from ₹ 2.7/kWh to ₹ 3.3/kWh, which is significantly lower than the per unit cost of capacity being contracted in states facing shortages. Therefore, there is a possibility for seasonal, medium-term contracts for surplus power with shortage states. In fact the states currently facing shortages, many of which also have a large number of non-electrified households, have been unable to contract power at favourable rates due to lack of creditworthiness or lack of interest from private generators. Institutional and contractual arrangements, which can utilise surplus power to cater to the demand in these states, are essential. Some such arrangements are the surrender and re-allocation of power at pooled price, medium-term sale of power, procurement of surplus power at concessional rates, etc. This can mitigate the high fixed cost payments by surplus states for idle capacity while reducing the requirement of shortage states to build more expensive plants.

For over two decades, the sector has been struggling to address the two crucial issues of excessive transmission and distribution losses (including commercial losses) and excessive cross-subsidy in tariffs. This has severely affected financial viability of the entire sector. Unless urgent attention is given to the management of surplus power and more importantly, preventing build-up of more surplus capacity, this would become an equally significant challenge to the financial viability of the sector. The issue of surplus capacity would be more difficult to address as it involves huge capital investments, lock-in of scarce resources and long term legal contracts, often with private sector developers.

The Price of Plenty: Insights from 'surplus' power in Indian States

"Water, water, everywhere,
And all the boards did shrink;
Water, water, everywhere,
Nor any drop to drink."

Samuel Taylor Coleridge
(The Rime of the Ancient Mariner)

1. Background and context

For the first time in decades, the Central Electricity Authority (CEA) projected that Distribution Companies (DISCOMs) in India will be power surplus in the year 2016–17, with a peak surplus of 2.6% and an energy surplus of 1.1% (CEA, 2016a). Several DISCOMs in states such as Gujarat, Punjab, Haryana, Maharashtra, and Madhya Pradesh had surplus capacity in 2015–16. On one hand, this is a positive development as it has addressed the constraint of availability of power to meet the needs of many. However, availability of power is just one important step on the road to reliable, affordable supply.

In most states, surplus power implies low utilisation of generation assets as available power is not scheduled or is 'backed down'. This has significant impacts on fixed cost payments made by consumers. At a national level, the CEA estimates suggest that about 15% of the total capacity was backed down in 2014–15 (CEA, 2016c).[1] In several states, the estimate is much higher with about 15% to 30% of the contracted capacity being backed down despite being available. Table 1.1 shows the extent of backing down in various states in the year 2015–16.

Table 1.1: Backing down of capacity in various states (2015–16)

State owned DISCOMs in:	Backing down reported (MW)	% of contracted capacity
Maharashtra[2]	4,231	19%
Punjab[3]	3,457	27%
Rajasthan[4]	1,798	14%
Madhya Pradesh[5]	2,444	17%
Gujarat[6]	5,525	30%

Source: PEG compilation from various regulatory petitions and orders

[1] This is based on a CEA study of 570 coal/lignite based thermal units (25 MW and above capacity) of 184 thermal power stations aggregating to 1,47,297 MW. The sample is significant as it is about 78% of the installed thermal capacity in India.
[2] Based on estimates of the DISCOM provided in petition for Case 46 of 2016 (MSEDCL, 2016).
[3] This is the quantum reported between April 2015 and September 2015 for Punjab (PSERC, 2016a).
[4] Rajasthan DISCOMs reported loss of 12,603 MU due to backing down for 2015–16 (JVVNL, 2016). Assuming a normative PLF of 80%, the capacity backed down is approximately 1,798 MW.
[5] Madhya Pradesh DISCOMs reported loss of 17,130 MU due to backing down for 2015–16 (MPERC, 2017). Assuming a normative PLF of 80%, the capacity backed down is approximately 2,444 MW.
[6] Based on backing down reported between September 2015 and March 2016 for Gujarat (GERC, 2016).

The rapid increase in sustained surplus capacity has raised many questions such as:

- How does power surplus affect DISCOMs? In spite of unmet demand, why is surplus power being backed down? Which plants are getting backed down?
- How did DISCOMs end up in the present predicament? Was there an unanticipated reduction in consumption due to sales migration and slow economic growth? Or was power procurement in excess of demand? Did renewable energy capacity addition have a role to play?
- What are states (DISCOMs, ERCs and state governments) doing to manage surplus? Are they selling surplus power? If so, how? What are the impediments in using surplus power to provide uninterrupted power supply to rural households or to meet the needs of shortage states?

Several analyses in the recent past have attempted to answer some of these questions at the national level. Still, there seems to be no comprehensive in-depth study of issues and trends at the state level, especially for DISCOMs managing surplus capacity. This report consolidates trends across states and identifies implications of the surplus capacity. It provides an integrated picture of the issue, especially with respect to demand estimation and capacity addition, which have contributed to the glut. The report also highlights important lessons from state experiences in managing surplus, suggests ideas to mitigate issues with surplus capacity, and articulates a way forward to prevent idle capacity in the future.

The objective of this paper is to identify trends, challenges and lessons from the experiences of various states providing key insights about the surplus issue at the national level. Therefore, the focus is not on any state in particular but to identify trends in power procurement and surplus management as a whole. The analysis in this report is based on state and central government documents, available data from various load dispatch centres, regulatory orders and petitions, as well as judgements of the Appellate Tribunal for Electricity (APTEL).

Even though India's power surplus situation has been the subject of significant debate and discussion, due to the evolving nature of the issue and varied practices across states, there is not enough information in the public domain, and there is lack of consistency in available data. This is especially true of upcoming capacity reported by the Electricity Regulatory Commissions (ERCs), state governments and DISCOMs. Moreover, scheduling practices and deviations from merit order are not documented in a systematic manner. There is also lack of consistency in how backing down is reported. Some DISCOMs and ERCs only report projections for backing down as opposed to actuals and there is a wide variation in terminology for reporting these estimates as well which include economic shutdown, boxing up, etc. We have made the best possible effort to document and analyse available information given the constraints. This poses a challenge to ensure complete accuracy in analysis but we are confident that this does not affect the larger observations, commentary and conclusions drawn from the insights.

2. What is surplus power and why is it important?

A DISCOM has surplus power when the availability of contracted power is higher than the demand it caters to on a sustained basis.[7] Unless the DISCOM can find a buyer for the contracted surplus power, it is stuck with idle capacity. Most power procurement contracts are take-or-pay contracts that have a two part payment system: a fixed annual payment to cover fixed costs, and variable charges to cover fuel and running costs. In most cases, contracted generating capacity should be scheduled to meet demand based on merit order principles. In an ideal scenario, this implies that power is dispatched based on its variable cost such that the cheapest power is first used to meet demand. Generators with a higher variable cost of power are lower down in the merit order stack and will not be scheduled if there is no demand. This is called backing down. As per merit order, hydro and nuclear power plants as well as renewable energy capacity is to be scheduled first or is "must run". If power is un-requisitioned despite being available (in other words, is backed down), the DISCOM has to bear the fixed charges as per the contract. When availability of power is more than energy requirements, adherence to merit order principles implies that more expensive thermal power plants lie idle, with consumers bearing the fixed cost. Most DISCOMs reporting surplus are currently dealing with backing down thermal capacity, and as a consequence face significant cost impacts, as depicted in Table 2.1.

Table 2.1: Backing down payments as a proportion of total fixed cost payments to generators

DISCOMs in:	Fixed cost payments due to backing down (₹ Cr)	% of total fixed cost payments to generators
Rajasthan	1,051	16%
Punjab	3,006	33%
Maharashtra[8]	2,828	21%
Madhya Pradesh	2,177	28%
Gujarat	3,823	36%
Haryana	443	7%

Source: Prayas analysis based on DISCOM tariff and additional surcharge petitions and various regulatory orders.

It is evident that a significant proportion of fixed costs is being paid for capacity that did not generate power. As power procurement accounts for about 75% of DISCOMs expenses, such payments can also have a significant impact on either consumer tariffs or DISCOM losses.

[7] Intermittent mismatch between demand and supply is understandable especially when DISCOMs face the challenge of supplying to a large number of diverse consumers. This report is more concerned with instances of sustained surplus which could lead to significant backing down and the risk of capacity lying idle.

[8] Unlike other states, where the estimate is for 2015-16, MSEDCL estimates are for 2016-17 as this is the only available recent estimate of fixed costs (MERC, 2016).

Paradoxically, surplus power co-exists with access deficit and long outages in many parts of the country, as highlighted in Box 2.1

Box 2.1: Surplus and the long road to access

The presence of sustained surplus in many states and the likelihood of marginal surplus at the national level cannot be construed as adequate access for all in the country. Despite many strides towards ensuring reliable, affordable supply, a large number of households (about 55 million) still do not have access to electricity connections. Households and small enterprises face significant outages and poor quality supply which is not restricted to just rural areas. Data captured by Prayas' Electricity Supply Monitoring Initiative (ESMI), available at www.watchyourpower.org, indicates that many urban areas, including some megacities, routinely experience power outages of more than 20 hours per month. In rural areas, several locations experience outages of more than 100 hours per month (PEG, 2016). Even among those who have connections, a significant proportion of households consume less than 50 units per month, which is only enough to cater to just the basic minimum electrical needs in a household. For example, in Andhra Pradesh, DISCOMs have reported that about 40% of households use less than 50 units per month and in Madhya Pradesh about 50% of the metered households use less than 50 units per month (MPPMCL, 2016; APSPDCL, 2017). These realities highlight that, apart from enough generation capacity, issues such as the structural disincentive before DISCOMs to supply adequate power to all, adequate investments in and maintenance of sub-transmission and distribution systems, and rigorous monitoring of supply quality, also need to be addressed to ensure access to all.

The focus of this report is on the nature and causes of the surplus power in Indian states and as such it does not dwell on the gamut of issues related to universal, affordable and quality access of power supply. However, this is an important issue which requires concerted efforts and support.

The instances and trends in backing down are different across states and offers important lessons as detailed in Section 2.1

2.1 Tracking 'backing down'

Though many states are projected to be surplus as per the CEA and the respective State Electricity Regulatory Commission's (SERC) orders, a fewer number of states have been actually reporting surplus in the past. This section looks closely at the trends in some of these state-owned DISCOMs. The analysis focuses on the quantum of surplus, the type of plants being backed down,[9] and highlights key trends. These include trends in loss of generation due to backing down, analysis of the type of capacity being backed down especially it's based on fuel source, ownership, age and fixed cost. The focus is on state-owned DISCOMs in states which were facing severe power shortages as

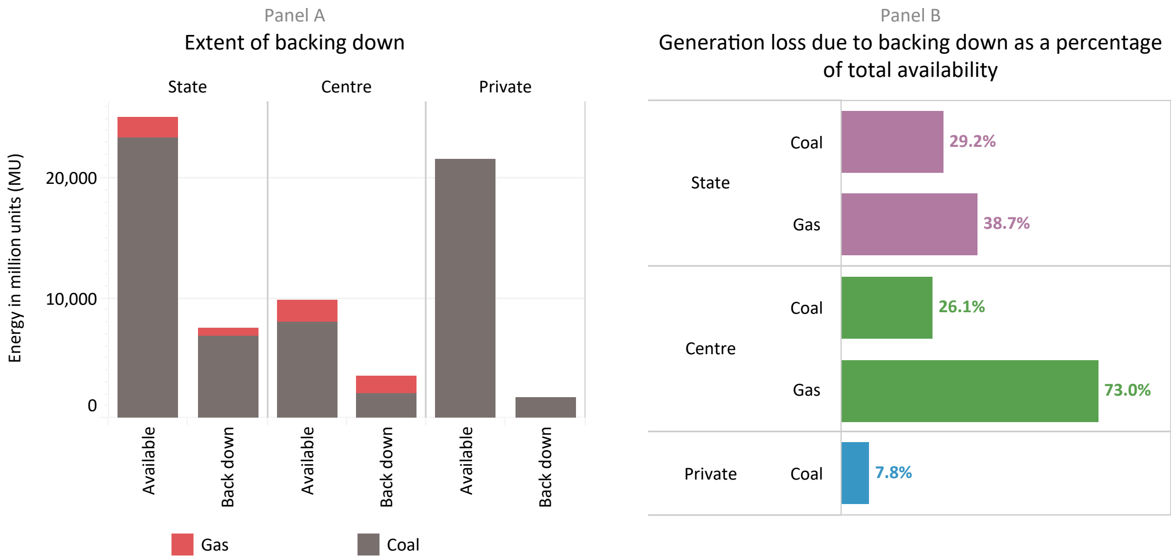
[9] Though scheduling practices; adherence to and deviations from the merit order is closely linked to backing down and needs to be studied, it is beyond the scope of this report and thus, is not analysed.

recently as 2009–10, but which are currently surplus. These include Rajasthan, Punjab, Haryana, Maharashtra, Madhya Pradesh, Gujarat, Andhra Pradesh and the newly formed Telangana state.

2.1.1 Rajasthan

As of 2015-16, Rajasthan DISCOMs have contracted about 12,743 MW and purchased about 69,500 MU of power. The state generating company RVUNL has been reporting marginal loss of generation due to backing down since the year 2009–10, which grew to 3,438 MU by 2014–15 (RVUNL, 2015).[10] This accounts for about 11% of the gross generation from RVUNL stations. By 2015–16, the reported loss of generation due to backing down for all the DISCOMs was 12,603 MU which accounts for about 18% of the total power purchased that year. (JVVNL, 2016). Of this quantum, 6,150 MU were due to the state-owned generation stations such as the Kota Thermal Power Station (KTPS) (1,240 MW) and the Suratgarh Thermal Power Station (STPS) (1,500 MW) which were shut down for prolonged periods. The details of loss of generation from contracted capacity of thermal power plants due to backing down in 2015–16, reported by DISCOMs is shown in Figure 2.1.

Figure 2.1: Extent of backing down in Rajasthan (2015–16)



Source: JVVNL petition for additional surcharge (JVVNL, 2016)

Panel A shows the loss of generation due to backing down along with the availability based on fuel source and ownership of plant. Panel B shows the proportion of loss of generation due to backing down to total availability on the basis of fuel and ownership type.

Panel A clearly shows that about 84% of the loss of generation is due to backing down of coal fuelled plants, and that about 64% of this loss of generation is from backing down state-owned generating plants. Of the RUVNL stations, the Suratgarh Thermal Power Station (TPS) and Kota TPS with high variable costs of ₹ 3.73/kWh and ₹ 3.36/kWh respectively account for 68% and 22% of the loss of generation due to backing down in that order. Interestingly, about 10% of the loss of generation is due to backing down of capacity which was commissioned after 2009. Notable among them are the

[10] The quantum reported includes auxiliary consumption.

recently commissioned, state-owned Chhabra Thermal Power Station (1,000 MW) and Kalisindh Thermal Power Station (1,200 MW). Coal-based central sector plants about for about 16% of the total loss in generation. About 13% of the total loss of generation can be attributed to private sector capacity. Notable among them are the Kawai TPS of Adani Power (Rajasthan) Limited (contracted capacity of 1,020 MW) and Rajwest Power of JSW Energy (contracted capacity of 834 MW). Panel B shows that even though their contribution to total generation loss due to backing down is less, gas-based plants are backed down significantly as compared to their availability.

Even with significant backing down, approximately 5% of the power requirement of the DISCOMs in 2012–13 and 2014–15 was met through short-term sources. This, along with the partial back down of plants, implies that the available capacity is not able to meet the variations in demand over the year. Further analysis in this regard, was not possible due to paucity of data.

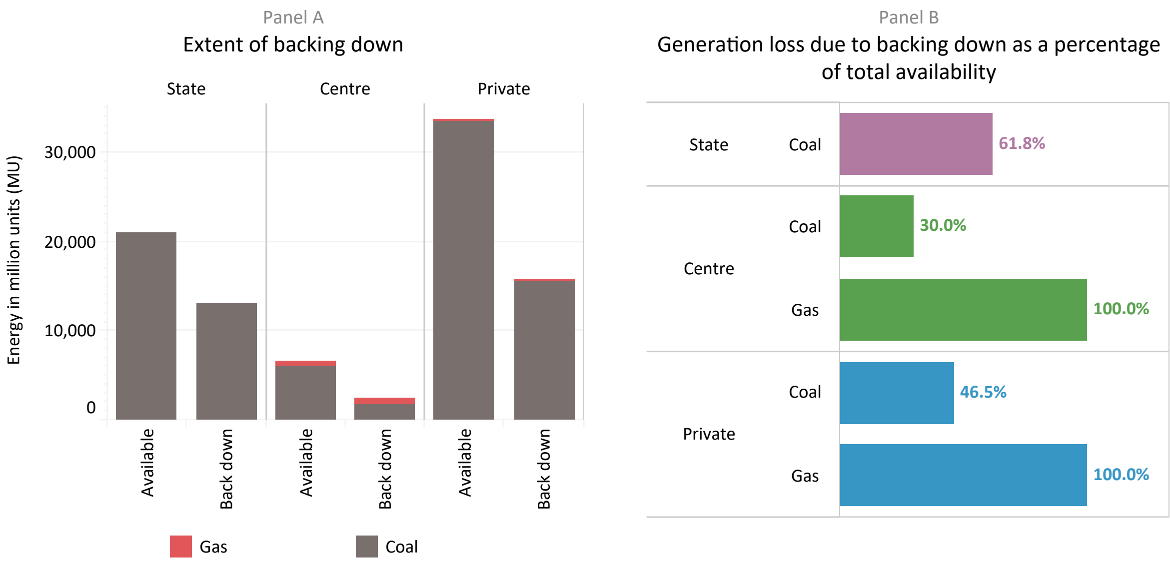
2.1.2 Punjab

The Punjab State Power Corporation Limited (PSPCL), the state-owned generation and distribution licensee, operates three thermal generating stations with a total installed capacity of 2,640 MW. The DISCOM has contracted about 12,611 MW of power in 2015-16 and purchased a total of 47,942 MU. In 2010–11, 772 MU of generation from PSPCL stations was lost due to backing down. By 2013–14, this quantum increased to 4,104 MU and by 2015–16 it was 8,055 MU. As the net generation from PSPCL stations for 2015-16 was 11,822 MU, this backing down is quite significant. As more details are not available of actual backing down, Figure 2.2 shows backing down projections approved by the SERC for 2016–17 for the DISCOM (PSERC, 2016c).

Panel A shows the projected loss of generation due to backing down along with the projected availability based on fuel source and ownership of plant. Panel B shows the proportion of projected generation loss due to backing down to total projected availability on the basis of fuel and ownership type.

Panel B clearly shows that all of the contracted gas capacity is effectively going to be backed down. Additionally, about 30% of the NTPC coal-based capacities which have a variable cost of above ₹ 2.79/kWh are also to be backed down. The state generating companies have variable costs ranging from ₹ 3.26/kWh to ₹ 3.4/kWh, mostly due to issues with coal availability and transport and face substantial backing down as shown in Panel B. The three state generating stations are partially backed down but many central and private generating stations are shut down throughout the year with DISCOMs bearing the fixed costs.

Figure 2.2: Projections for backing down in Punjab (2016–17)



Source: (PSERC, 2016c)

From Panel A, it is clear that about half of the loss of generation is due to the backing down of private generating stations. Surprisingly these stations have been commissioned between 2014 and 2016. The contribution to total generation as well as the fixed cost of these three plants is significant[11] as detailed in Table 2.2.

Table 2.2: Details of private generating capacity being backed down in Punjab (2016–17)

Name of plant	Contracted capacity (MW)	Generation available (MU)	Generation Loss[#] (%)	Fixed cost[12] (₹/kWh)	Variable cost (₹/kWh)	Year of COD[13]
Talwandi Sabo TPS (Sterlite)	1,980	12,905	73%	2.34	2.59	Unit 1: 2014 Unit 2:2015 Unit 3:2016
NPL Rajpura TPS (L&T)	1,400	9,829	25%	3.05	2.06	2014
Goindwal Sahib TPS (GVK)	540	3,784	100%	2.18	2.66	2016

[#]This refers to generation loss due to backing down as a proportion of total availability of the station

Source: (PSERC, 2016c)

Punjab DISCOMs are looking to surrender 2,247 MW of capacity from private generating stations to mitigate fixed cost impacts. As expected, generators have not welcomed this proposal and as of now DISCOMs are bearing the fixed costs (PSERC, 2016c).

[11] These three plants alone account for 43% of the total power available and 38% of the total fixed cost payments to generators.
[12] Assuming that the fixed cost is spread over available generation
[13] Commercial Operation date (COD) of the plant used to show year of commissioning

It is a well-known fact that Punjab faces significant variation in demand. The PSPCL has surplus power in the winter months (2,200 MW) and faces a noteworthy power deficit in the summer months (1,600 MW in paddy season) (PSPCL, 2016, p. 276). The shortages in the summer months are met with short-term power purchase via traders and the power exchange. In 2012–13, the year when the state generating stations were backed down for 2,030 MU, the PSPCL procured 4,558 MU from short-term sources for an average rate of ₹ 3.79/kWh. By 2015–16 the quantum of short-term power procurement fell to 1,844 MU (PSPCL, 2016). In the recent years, Punjab has also been banking power with other states in the Northern Grid to meet its requirements and thus the quantum of purchase has reduced. This shows that like Rajasthan, even in case of Punjab, surplus and shortages coexist during a year because the surplus capacity, being largely coal-based is not suitable to meet the demand variations.

2.1.3 Haryana

By 2015-16, Haryana DISCOMs had a contracted capacity of 11,065 MW and was purchasing 48,858 MU of power. The Haryana State Power Generation Company Limited (HPGCL) has been reporting marginal backing down since 2007–08, which had grown to 8,447 MU by 2013–14, comparable to about 60% of HPGCL's net generation that year (HPGCL, 2014). In the same year, DISCOMs reported loss of 10,327 MU due to backing down (HERC, 2014b). Haryana DISCOMs submitted detailed information of backing down between October and March 2016 when filing the petition for determination of additional surcharge (UHBVN, 2016). In the six-month period, 4,526 MU was lost due to backing down, of which 32% can be attributed to the Indira Gandhi Super Thermal Power Project at Jhajjar.[14] Also, about 27% of the total generation lost in this period was due to the backing down of Adani Power Plant in Mundra (1,424 MW) and CLP's plant in Jhajjar (1,188 MW). The HPGCL plants contribute to 26% of the un-requisitioned power. Interestingly, more than 80% of the plants with capacity being backed down were commissioned after 2008, by which time the HPGCL was already reporting surplus. Much like Punjab, Haryana also experiences wide variations in peak demand with the summer peak close to 9,000 MW and the winter peak at 3,000 MW (HERC, 2015).This, implies the need for short-term power purchase in the face of surplus capacity. Of late this short-term, seasonal demand is being met via banking. Between 2013–14 and 2015–16, short-term power purchase has reduced from 334 MU to 14 MU, whereas banking has increased from 2,436 MU to 3,656 MU.

2.1.4 Maharashtra

As of 2015-16, MSEDCL, the Maharashtra State DISCOM, has a contracted capacity of about 22,569 MW with a total power purchase of 1,16,093 MU .Negligible quantum of loss of generation due to backing down was reported as early as 2011 by the Maharashtra State Power Generating Company Limited (MSPGCL). At that time, the Maharashtra State Electricity Distribution Company Limited (MSEDCL) was facing peak shortages but also had 700 to 800 MW of surplus during off-peak hours (MERC, 2012a).

In 2014, the Maharashtra Electricity Regulatory Commission (MERC) approved MSPGCL's proposal to shut down 5 units not because of surplus power, but due to issues with coal availability such that the coal can be utilised more efficiently in other plants (MERC, 2014a). This proposal also called 'economic shutdown', resulted in the backing down of 1,040 MW with a vintage of over 30 years.

[14] The plant is a joint venture between HPGCL, NTPC and Indraprastha Power Generation Company Ltd (IPGCL).

The consumers were to pay ₹ 214 crore fixed cost for the idle capacity. Many of the plants under economic shutdown are now decommissioned and coal allocated to these plants is being used by the MSPGCL in other plants.[15] In 2014–15, the MSPGCL lost 1,594 MU of generation (4% of total net generation) due to backing down instructions by the SLDC. Between April and August 2016, the MSEDCL reported backing down of 15,094 MU (which itself is the equivalent of about 13% of the total power purchase) from its entire contracted thermal capacity.

For the year 2016–17, the MSEDCL projected the backing down of about 4,231 MW of capacity but the question of which plants are to be backed down is being debated.[16] Due to monthly changes in variable costs and a lack of data on backing down in the past years, it is difficult to predict the extent of backing down faced by each plant. The MERC projected that for 2016–17, certain MSPGCL plants with a capacity of 1,760 MW are to be completely backed down. Even though the average age of the plants being backed down is 27 years, the 500 MW from Parli Unit 6 and Unit 7 being backed down were commissioned as recently as 2007 and 2010. Besides this, the contracted capacity of 404 MW NTPC gas-based plants in Kawas and Jhanor is also to be backed down.

The Maharashtra SLDC has been reporting the merit order schedule on a monthly basis. As per the monthly schedule from September 2016 to December 2016, privately owned capacity from Rattan India’s plant in Amravati (1,200 MW) and Adani’s plant in Tiroda (440 MW) were also backed down. These plants, which were contracted between 2012 and 2013, also have high fixed costs. Units 6 and 7 of Parli require about ₹ 1.06/kWh in fixed costs; the Rattan India plant gets ₹ 2.55/kWh and Adani Power Maharashtra Limited’s (APML) plant at Tiroda costs about ₹ 1.4/kWh. The MERC projections of the merit order stack also indicate that all 656 MW of the contracted capacity from NTPC Solapur will be backed down in 2017–18, the year it will be commissioned.

2.1.5 Madhya Pradesh

The total contracted capacity for Madhya Pradesh DISCOMs was 14,785 MW in 2015-16. The Madhya Pradesh Power Generating Company Limited (MPPGCL) reported loss of 2,035 MU due to backing down in 2013–14 and it reported loss of 3,332 MU in 2015–16 for the same reason. In the year 2016–17, the commission projected a surplus of 23,122 MU for the DISCOMs. This is about 28% of total available generation from total contracted capacity of Madhya Pradesh DISCOMs.[17]

The DISCOMs proposed to surrender power from NTPC stations of Mauda, Kawas and Gandhar (a total of 428 MW) and MPPGCL decided to shut down its ATPS Chachai (240 MW) plant (MPERC, 2016b). Figure 2.3 highlights key trends in the backing down as projected by the DISCOMs.

Panel A shows the projected loss of generation due to backing down along with the projected availability based on fuel source and ownership of plant. Panel B shows the proportion of projected loss of generation due to backing down to total projected availability on the basis of fuel and ownership type. About 44% of the loss of generation due to backing down is from state-owned

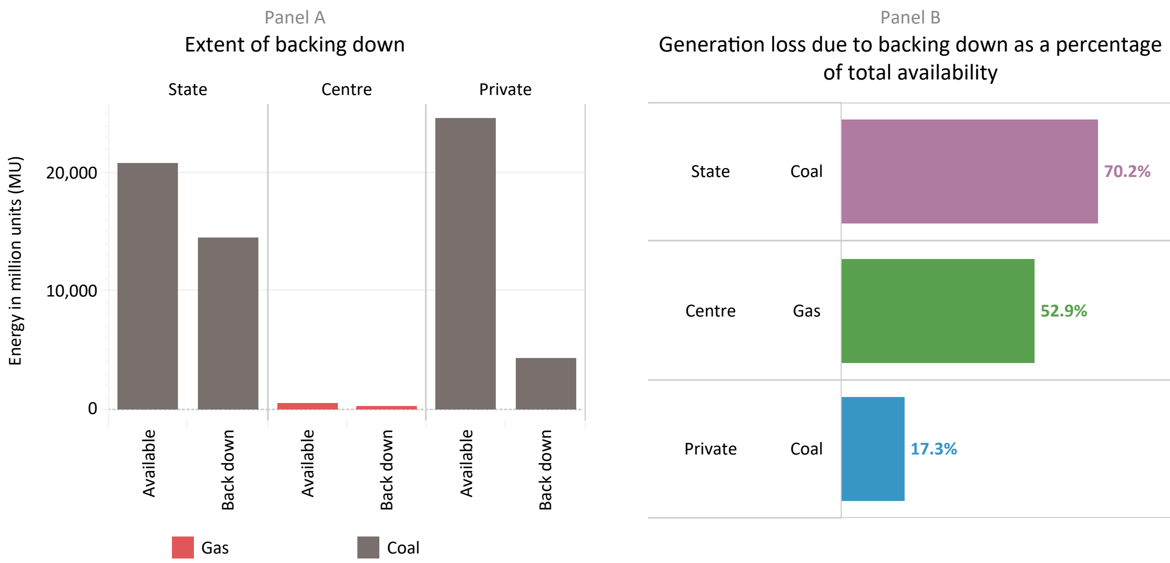
[15] From the year 2016–17, the plants which faced economic shut down such as Chandrapur 1&2 and Bhusawal 2 are to be retired. Koradi 5 will be retired in 2017–18. Similarly, for 2016–17, Parli 3&4 is facing reserve shut down and Koradi 6 is under repair and maintenance.

[16] Petitions have been filed with respect to the merit order despatch, technical minimum assumptions for generating stations and whether variables costs, used to estimate merit order and thus backing down included fuel adjustment charge and other relevant charges.

[17] If ERC estimates are to be considered, it could also include backing down from MPPGCL’s plant at Satpura and Phase 2 of NTPC’s Kahalgaon plant. As the merit order was not clearly given, these plants were not considered for the analysis.

generating companies. The state-owned generating station Singhaji Thermal Power Plant (TPP) in Khandwa, commissioned as recently as 2014 with an installed capacity of 1,200 MW and fixed cost of ₹ 1.37/kWh, was also proposed to be backed down. Panel B reiterates the significant loss of generation due to backing down for state generating plants and also makes it clear that the gas-based capacity backed down was minuscule. In fact, NTPC's plant at Kawas was the only gas-based capacity backed down.

Figure 2.3: Backing down projected for Madhya Pradesh DISCOMs in 2016–17



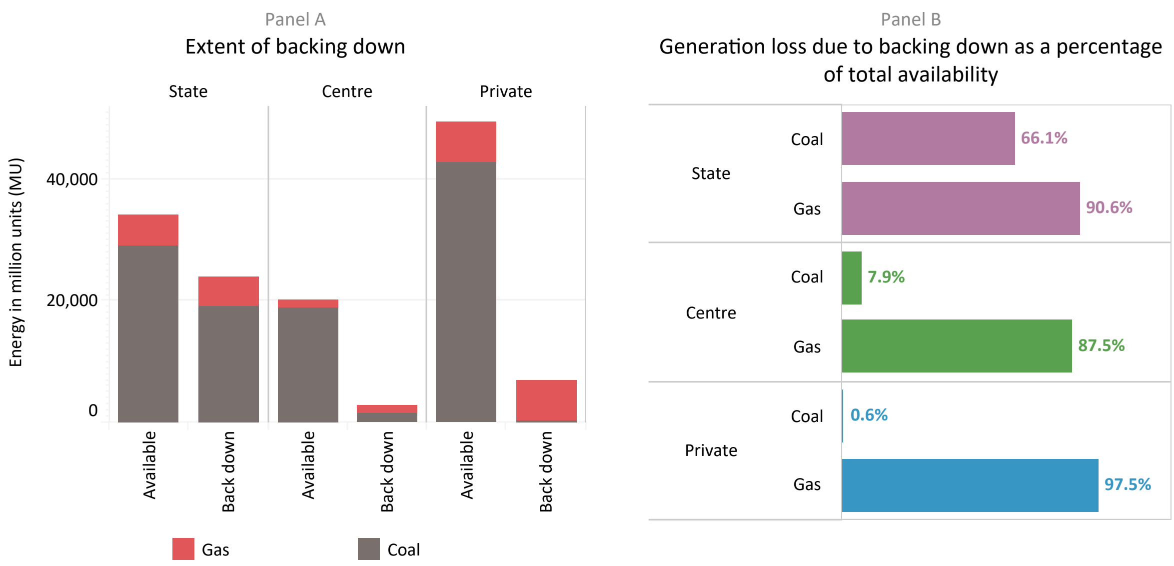
Source: (MPERC, 2016b) (MPPMCL, 2016)

The most curious case is that of privately-owned capacity which are proposed to be backed down about 75% of the time. Commissioned recently, these plants have among the highest fixed costs in the country. Jaypee plant in Bina and Jhabua Power's plant in Seoni are cost-plus projects which were commissioned by 2013 and 2016 respectively. The former has a fixed cost of about ₹ 2.18/kWh and the latter has a fixed cost of ₹ 1.54/kWh.

2.1.6 Gujarat

Gujarat DISCOMs had contracted capacity amounting to 18,131 MW in 2015-16 and were purchasing 81,125 MU of power in 2015-16. In the year 2010–11, the Gujarat State Electricity Corporation Limited (GSECL), a state-owned generating company, lost 2,788 MU (comparable to 11% of net generation from GSECL) due to backing down, and by 2012–13, this quantum had increased to 6,026 MU (comparable to 28% of generation from GSECL in that year) (GERC, 2012; GERC, 2014).Based on the availability and generation scheduled in 2014–15, it is estimated that the GSECL lost 15,222 MU of generation due to backing down. The average backing down is about 5,000 MW which is comparable to the capacity allocated from NTPC for the DISCOMs. The backing down estimated by the DISCOMs for the year 2016–17 is reported in Figure 2.4 .

Figure 2.4: Backing down estimated by DISCOMs in Gujarat for 2016–17



Source: Petitions of DISCOMs for the year 2017–18.

Panel A shows the loss of generation due to backing down along with the availability based on fuel source and ownership of plant. Panel B shows the proportion of loss of generation due to backing down to total availability on the basis of fuel and ownership type.

Panel A and Panel B clearly show that even though gas-fuelled plants account for about 20% of the contracted capacity of Gujarat DISCOMs, most of the backing down can be attributed to coal-based capacity. The GSECL plants account for 71% of the 33,384 MU estimated to be lost due to backing down in 2016-17. Of the private capacity that is backed down, 96% is gas-based. Half of this is due to Paguthan Combined Cycle Power Plant (CCPP) owned by CLP (India) Limited, and the other half is due to state-owned gas-based Independent Power Producers (IPP). [18] Of the central sector contracted capacity, only the gas-based plants of NTPC in Kawas and Gandhar and the recently commissioned Mouda TPS (coal-based) were being backed down (MGVCL, 2016). In addition, just as in the case of MSEDCL, Gujarat DISCOMs have also projected the backing down of upcoming capacity from its expected year of commissioning. The NTPC Mouda Stage II Unit 2 (147 MW) is expected to be backed down from 2017–18 and GSECL's Wanakbori Extension Unit 8 (800 MW) is expected to be backed down from 2019–20.

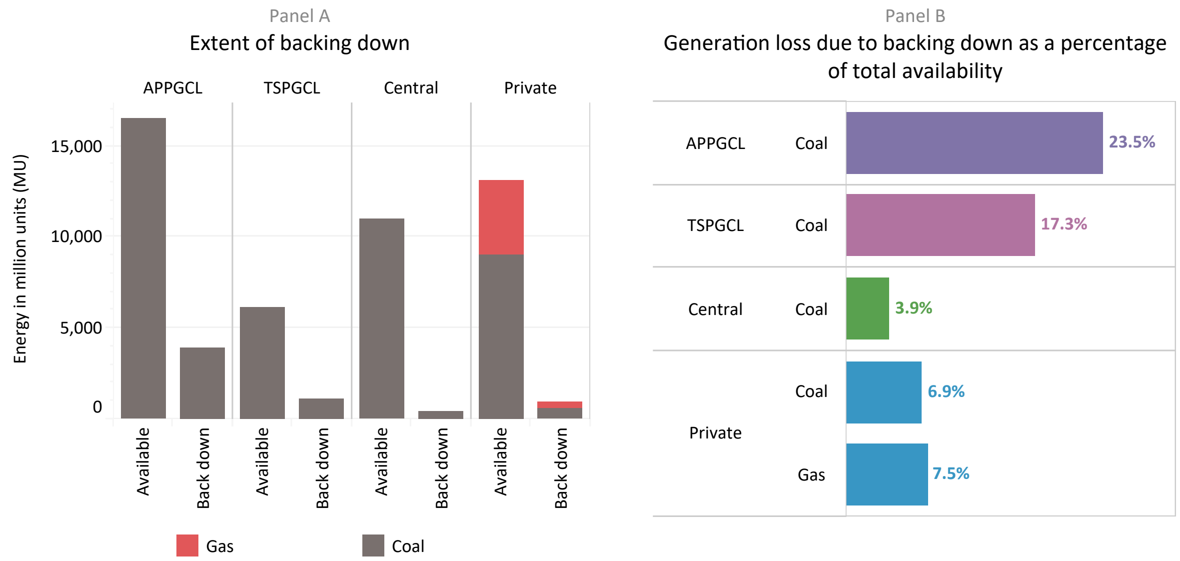
2.1.7 Andhra Pradesh and Telangana

The erstwhile ERC of unified Andhra Pradesh observed that the SLDC had backed down capacity resulting in a generation loss of 3,000 MU during 2010–11 and 1,250 MU in 2011–12 (APERC, 2012). The Commission also noted that this capacity was low cost and such backing down was to 'accommodate 'round the clock (RTC) purchase' (APERC, 2012, p. 47), of short-term power. In the

[18] These include plants of Gujarat Industries Power Company Limited, a state-owned company, and Gujarat State Energy Generation Limited and Gujarat State Petroleum Corporation's (GSPC) Pippavav Power Company Limited, both of which are subsidiaries of the Gujarat State Petroleum Corporation (GSPC)

year 2013–14, backing down of the state-owned generating company's stations resulted in a marginal generation loss of 1,149 MU (APPGCL, 2017). With the creation of Telangana, contracted capacity of the erstwhile state had to be shared between the two states. This is explained in greater detail in Section 3.2.8. Therefore, both Andhra Pradesh and Telangana procure power from the Andhra Pradesh Power Generation Corporation Limited (APPGCL) and the Telangana Power Generation Corporation Limited (TSPGCL). The recent filings of the DISCOMs in both states report estimates for backing down for the current year, 2016–17. The loss of generation due to backing down is not as substantial as other states but is bound to grow in the future. Figure 2.5 highlights major trends for Andhra Pradesh.

Figure 2.5: Backing down estimates by Andhra Pradesh DISCOMs for 2016–17



Source: (APEPDCL, 2017) (APSPDCL, 2017)

Panel A of Figure 2.5 shows the available generation as well as generation loss due to backing down on the basis of fuel and ownership. Panel B shows that extent of backing down with loss of generation due to backing down as a proportion of available generation. The average proportions are depicted on the basis of fuel use and ownership.

The state generating stations are split to denote if the capacity is owned by Andhra Pradesh Power Generation Company Limited (APPGCL) or Telangana State Power Generation Corporation Limited (TSPGCL). The graph in Panel B also makes a distinction between APPGCL and TSPGCL operated plants. While the quantum of backing down is not substantial as it accounts for only 13% of the total availability, about 62% of the total loss of generation is due to backing down of APPGCL plants and only 17% due to TSPGCL. Most thermal power plants are partially backed down across the year. Panel B shows that, on an average about 24% of APPGCL's generation is not scheduled as APPGCL plants have a high average variable cost. Of the allocation from central generating stations and joint ventures, the plants of Neyvelli Lignite Corporation TPS Stage II (94 MW) are the only partially backed down plants. Vizag TPP of Hinduja (1,040 MW), commissioned in 2016, is expected to have a marginal loss of generation. Additionally, gas-based IPPs lose only 7% of generation due to backing down (unlike the case in Gujarat). Most of this generation loss can be attributed to the 217 MW

Jegurupadu CCPP Phase 1 commissioned in 1997 and recently acquired by the Andhra Pradesh DISCOMs in 2015-16.

In spite of surplus, Andhra Pradesh DISCOMs have been relying on short-term power procurement to tackle variation in demand as well as to optimise costs. In 2015–16, DISCOMs reported short-term purchase of 7,041 MU at ₹ 5.16/kWh for 2015–16 and in 2016–17 when significant back down of capacity was projected, DISCOMs estimated short-term purchase requirement of 1,193 MU at ₹ 4.43/kWh.

Telangana DISCOMs have estimated only a marginal loss of 2.41% of total availability of thermal stations (1,022 MU) due to backing down in 2016–17. Of this, 62% can be attributed to backing down of high cost APPGCL plants, and 33% can be attributed to the backing down of the gas-based capacity of Pioneer Gas Power Limited, which was commissioned in 2016. For 2015–16,Telangana DISCOMs reported the procurement of 11,175 MU of short-term power, and in 2016–17 it estimated procurement of 7,361 MU of short-term power at ₹ 5.31/kWh to meet about 15% of its power requirement. The short-term rate for power purchase, approved by the Telangana Commission for the year 2016–17 was ₹ 4.29/kWh as this was the rate approved by the APERC for sale of surplus power for the same year. Under the Andhra Pradesh Re-organization Act of 2014, in case of surplus power with APPGCL stations, Telangana State DISCOMs have the first right of refusal. However instances have been reported where Telangana DISCOMs have been asked to pay ₹ 5.35/kWh which is higher than the ₹ 4.29/kWh approved for sale of surplus by the Andhra Pradesh ERC (TNN, 2016). It is also interesting to note that Telangana DISCOMs have been contracting power from the Indira Gandhi Super Thermal Power Station (IGSTPS)-Jhajjar[19], a station which has been backed down in Haryana, Rajasthan, Delhi and Punjab. Therefore Andhra Pradesh and Telangana only have marginal surplus capacity which can be managed in the current context. With large-scale capacity addition and fall in future demand, it could get as significant as in the case of Gujarat or Maharashtra.

2.2 Lessons and observations

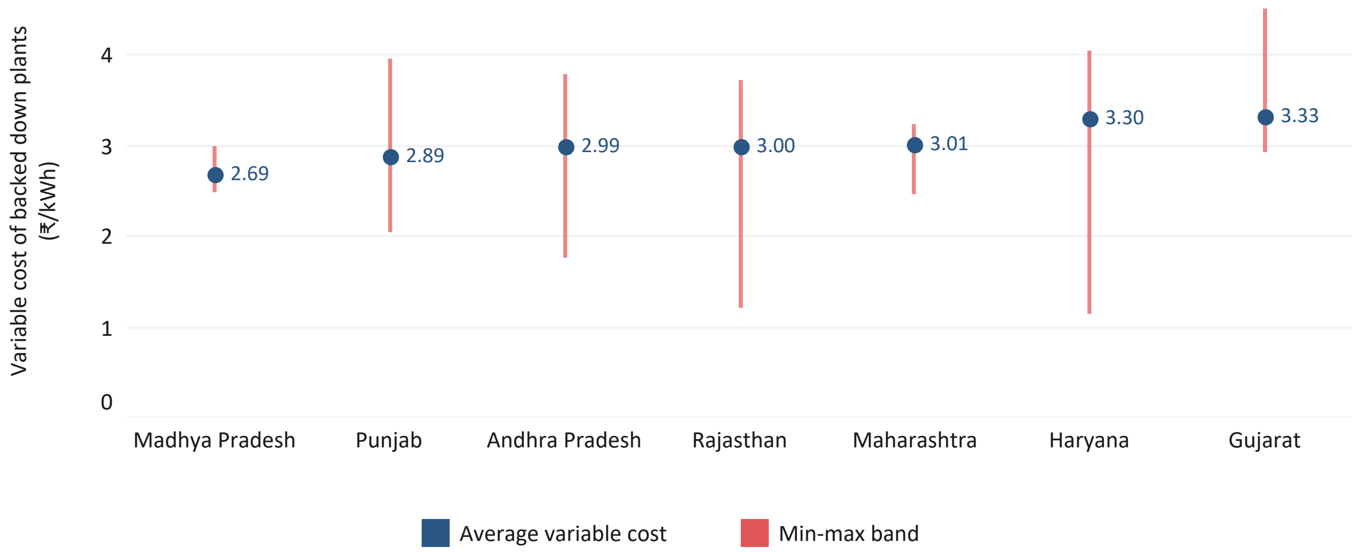
Analysis of data reported by DISCOMs and approved by the Commission point to interesting trends. The majority of the loss of generation due to backing down can be attributed to backing down of state-owned generation stations. This is true for all states discussed in the section above except Punjab, where the backing down of newly commissioned private capacity contributes most to the total loss of generation, and Haryana where the backing down of IGSTPS- Jhajjar has had the maximum impact . One of the reasons for this could be the fact that state-owned generation stations have higher variable costs than private and central sector plants. The difference in variable cost is not very significant as state-owned plants are on an average about 8% higher than private plants and 2% higher than central sector plants.

Due to fuel availability issues, gas-based plants have been almost completely backed down in all the listed states. Still, even in states with significant gas-based capacity such as Gujarat, Andhra Pradesh and Telangana, backing down of coal-based capacity is responsible for majority of the generation loss. Therefore, backing down is not due to gas unavailability alone but due to issues with managing demand and supply.

[19] The power has been allocated on a short-term basis from the de-allocated share of Delhi and Haryana DISCOMs.

Another important observation is that instances of surplus are seasonal and periodic for many states. DISCOMs in Punjab, Haryana, Rajasthan, Andhra Pradesh and Telangana have periods of power deficit and power surplus in the same year and thus have to depend on short-term power purchase and banking arrangements to meet demand. Therefore, surplus power need not imply the absence of shortages or short-term power purchases. Part of this may be due to inefficient management of demand and supply, and part of it could be attributed to technical constraints. Instances of shortages and surplus in the same year highlights the need for more sophisticated power procurement planning practices. It also points towards the need to develop market based instruments to enable seasonal trade. Perhaps due to the seasonal nature of surplus, plants are often partially backed down and only those plants with substantially high variable costs are shut down for prolonged periods of time. Some examples of shut down plants include plants such as RUVNL's Suratgarh TPS, Goindwal Sahib TPS, contracted by Punjab DISCOMs, and GSECL's Ukai TPS. The strategies for trading surplus power should consider the seasonal nature of surplus and the high variable cost of shut down capacity.

Figure 2.6: Variable cost (average, maximum and minimum) across states (2016–17)



Source: PEG analysis based on approved costs from tariff orders.

Figure 2.6 shows the average minimum and maximum approved variable cost for 2016–17 of coal-based thermal generating stations which have been backed down for more than 50% of availability. Most of this capacity has variable costs within the range of ₹ 2.7/kWh to ₹ 3.3/kWh.

Table 2.3 denotes the variable costs of newly contracted and added capacity in states with significant power deficit such as Tamil Nadu, Bihar and Karnataka. In states with significant shortages, the variable cost of backed down capacity is much less than the total cost of recently contracted capacity. Hence, there seems to be room for trade.[20] Such trade can reduce the requirement of states facing shortages to contract new capacity.

[20] This is assuming that transmission constraints do not hinder trade or reduce viability of trade.

Table 2.3: Cost of newly commissioned plants in states with shortages (₹/kWh)

DISCOMs in:	Power contracted from:	Contracted capacity(MW)	Latest approved total cost (₹/kWh)
Bihar	Adani Power Limited	200	5.70
Uttar Pradesh	Bara Thermal Power Station (PPGCL)	1,188	4.32
Tamil Nadu	NLC Expansion Unit 1	115	4.34
	Adani Power Limited	200	5.8
Karnataka	Bellary TPS Unit 3 (KPCL)	700	3.12
Kerala	Competitive bidding (DBFOO basis)[21]	675	4.15 to 4.29[22]

Source: PEG analysis based on tariff orders from various states

The average age of contracted capacity which is backed down for more than 50% of its availability in Gujarat, Maharashtra, Andhra Pradesh, Punjab, Madhya Pradesh and Rajasthan is about 17 years. This implies that in most states, plants which are being backed down are not fully depreciated plants and thus the fixed cost payments can be significant. An alarming development emerging in some states is the significant backing down of capacity that has been commissioned in the last five years as captured in Table 2.4.

Table 2.4: Built and backed down[23]

Ownership	DISCOMs in:	Station	Contracted capacity (MW)
Private	Punjab	Talwandi Sabo TPS	1,980
		Goindwal Sahib TPS	540
		NPL Rajpura TPS	1,400
	Maharashtra	Rattan India (Amravati)	904
	Madhya Pradesh	Jhabua Power (Seoni)	210
		Jaypee (Bina)	350
State	Maharashtra	Bhusawal Unit 4 & 5	1,000
	Rajasthan	Ramgarh TPS (Stage 3)	160
		Chhabra TPS (Unit 5)	660
	Madhya Pradesh	Singhaji TPP	1,200
Central	Gujarat	Wanakbori 8#	800
		Mouda Stage 2 Unit 2#	147
	Maharashtra	NTPC Solapur#	202

These plants have not been commissioned as yet but are projected to be backed down.

Source: PEG analysis based on regulatory orders and submissions

Table 2.4 also includes plants which are not yet commissioned but which are projected to be backed down right from the expected year of commissioning! It should also be noted that most of the states have reported growing surplus even before these plants were commissioned.

[21] Power from Bharat Aluminium Co Ltd (Chhattisgarh)(100 MW), M/s Jhabua Power Limited (Madhya Pradesh) (215 MW), M/s Jindal Power Limited (250 MW), M/s East Coast Energy Private Limited (Andhra Pradesh) (100 MW)

[22] These are the rates discovered during the bidding process. Procurement subject to approval from Government of India and the Government of Kerala due to deviations from the bidding guidelines. Of this capacity, approval for procurement of 215 MW from Jhabua Power was already been given.

[23] Some of this contracted capacity is partially backed down and not shut down.

3. How did DISCOMs end up with surplus power?

Surplus power exists due to a mismatch between demand and supply. A slight lag or lead between demand and supply and intermittent shortages are expected and is part of managing the power system. But, consistent excess capacity or sustained surplus is a matter of serious concern. The three major trends which can be identified as causes of this sustained surplus are:

- lower demand growth than anticipated – primarily due to unrealistically high estimation of future demand;
- massive capacity addition in the recent past based on unrealistic expectation of growth in demand
- reduction in demand for DISCOM power due to increased sales migration to open access, captive options;

This section discusses the contribution of these trends to the surplus situation and infers lessons for future planning. With the advent of open access and captive generation, many consumers, especially high paying consumers, have been migrating away from the DISCOMs, contributing to the reduction in demand. The actual contribution of such migration to the current predicament as well as possible impacts in the future because of increased open access and captive consumption is discussed in Section 3.1.

Section 3.2 looks at the growth of capacity addition in the recent past and examines its contribution to surplus power today. As demand forecasts have been crucial to power procurement planning, this section also explores issues with demand estimation and forecasting exercises. In particular, it looks at the Central Electricity Authority's medium-term and long-term demand forecasts as part of the Electric Power Survey, which is heavily relied on by states for planning future capacity addition. This section also focuses on the extent of capacity addition in the pipeline across states to highlight the scale of the problem and question the need for future capacity addition.

3.1 Sales migration: Driver or passenger?

An unexpected fall in demand due to sales migration has been identified as one of the causes of surplus power in states. Several SERCs have also levied an additional surcharge on open access consumers to compensate the DISCOMs for backing down costs attributable to open access. Information provided in DISCOM petitions and SERC orders for the levy of additional surcharge over the years shows that open access alone is responsible only for a fraction of the total backing down. Gujarat DISCOMs have provided information on the estimated contribution of open access to backing down for every six months since October 2013. This is shown in Table 3.1.

Table 3.1: Backing down attributable to open access in Gujarat

Period	Backing down (MW)	Estimated contribution of open access to backing down (MW)
October 2013 to March 2014	5,085	784
April 2014 to September 2014	3,459	320
October 2014 to March 2015	4,355	470
April 2015 to September 2015	4,322	458
October 2015 to March 2016	5,525	538

Source: Additional surcharge orders of GERC

It is clear from Table 3.1 that between October 2013 and March 2014 only 15% of the total backed down capacity could be attributed to open access. In 2014–15 and 2015–16 this reduced to 10% of the total quantum. Table 3.2 details the contribution of open access to backing down as reported by other state DISCOMs in various petitions and regulatory orders.

Table 3.2: Contribution of open access to total backing down

State	Period	Contribution of open access to backing down
Madhya Pradesh	2015-16	69 MW (3%)of 2,444 MW[24]
Punjab	April to September 2015	224 MW (10%) of 2,210 MW
Maharashtra	2016-17 (projections)	1,620 MW (25%) of 6,379 MW
Haryana	2013-14	269 MW (18%) of 1,474 MW [25]
	October 2015 to March 2016	157 MW (25%) of 626 MW[26]

Source : (MPERC, 2016c) (PSERC, 2016b) (MERC, 2016) (HERC, 2014c) (UHBVN, 2016)

Thus in most states, it is evident that open access is a contributor but not the major reason for backing down of power. It is also clear that the contribution of open access is growing. Rajasthan DISCOMs seem to be an exception. Between April 2015 and January 2016, RERC estimated that 623 MW were lost on account of backing down. Of this, 368 MW, almost 60% of the total capacity backed down, could be credited to open access (RERC, 2016a). [27]

Open access has been operationalised for almost a decade now and the volume of open access transactions has been increasing. Thus, the reduction in sales due to open access is not unexpected. Demand estimation exercises and capacity addition plans should have taken this into account. In fact, as discussed in Section 3.2, many SERC regulations and guidelines for medium-term demand forecasts have provisions for this purpose, but the optimistic nature of projections shows that reduction of sales due to growing open access is seldom considered during forecasting and planning.

Evidence from the growing quantum of open access transactions in day ahead markets and data from DISCOMs' regulatory filings indicate that the majority of open access today is short-term. Due to its intermittent nature, estimating and projecting *short-term open access* is challenging and it creates problems for power procurement planning. Short-term open access, usually availed for a period of up to one month can be for weekly or even daily durations. As consumers frequently switch between the DISCOM and the market, based on price signals, short-term open access (OA) contributes to variability in demand, which makes forecasting challenging. States such as Punjab, Haryana and Rajasthan have identified short-term open access as an issue in future planning and in ensuring smooth operations. According to PSPCL in Punjab,

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[24] 483 MU were backed down due to open access. This total quantum backed down as well as the backing down due to open access was reported in energy terms. For ease of comparison, this was converted to MW by assuming a normative PLF of 80%.

[25] 1,884 MU of the 10,327 MUs backed down due to open access. For ease of comparison, this was converted to MW by assuming a a normative PLF of 80%.

[26] 1,097 MU of 4,386 MU were backed down due to open access. This was converted to MW by assuming a normative PLF of 80%.

[27] The ERC estimated the contribution of open access to be 2,852 MU of the 4,826 MU of generation loss due to backing down. This was converted to MW by assuming a normative PLF of 80%.

'The [short-term] OA consumer, without giving any notice, takes the power through the open access in case the power is cheaper through OA…So PSPCL has to surrender without any fault, costly power at a lower rate as PSPCL is not in a position to find alternative consumer(s) for this power instantaneously . On the other hand, as the frequency goes down the UI [Unscheduled Interchange] rate increases, the cost in power exchange also increases and then open access consumer immediately shifts to PSPCL power. This unexpected load on PSPCL system becomes unmanageable and PSPCL is compelled to resort to load shedding on other remaining consumers. PSPCL is never sure about the quantum of the power which the open access consumer is going to tie up on its own.' (PSERC, 2010, pp. 51-52)

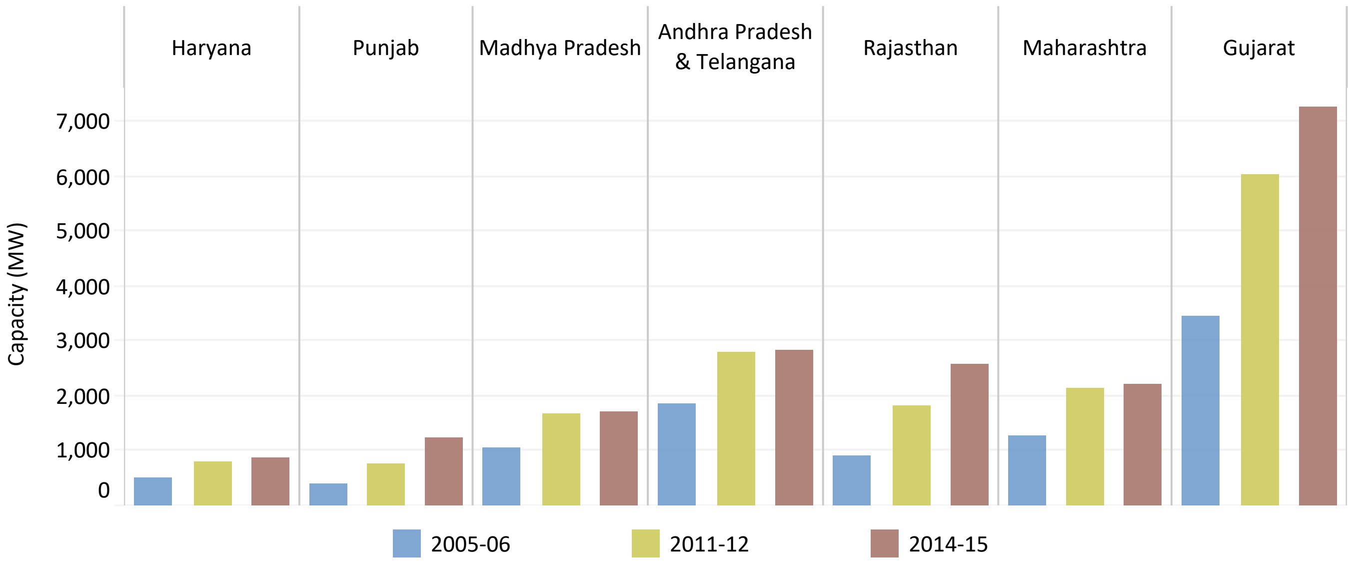
Similarly, the Rajasthan DISCOMs reported that:

'Short-term open access consumers generally procure energy from collective market or power exchanges due to which there has been considerable variation in schedule and actual energy drawal of these consumers. These consumers reschedule their energy drawal on the basis of their daily load requirement. Such anomaly in energy drawal makes it difficult for the Discoms to forecast their energy requirement for the following day.' (RERC, 2016a, p. 2)

As volumes increase, short-term open access will not only lead to backing down but will also make demand estimation and power procurement planning difficult.

Captive power generation by consumers is also responsible for sales migration. Data on installed capacity compiled by the CEA in the All India Electricity Statistics (General Review) publication[28] indicates that the quantum of captive power consumption has grown significantly from 2005–06 to 2014–15. This is clear from Figure 3.1 below.

Figure 3.1: Growth of captive generating capacity over the past decade across states



Source: (CEA, 2016b) (CEA, 2013) (CEA, 2007a)

The quantum is substantial in all states with significant surplus, especially Gujarat. The consumption by captive plants has shown varying trends. In Maharashtra and Haryana consumption of power

[28] CEA compiles information on consumption of captive power plants with an installed capacity >1 MW.

from captive sources *reduced* between 2005–06 and 2014–15 by 1,714 MU and 139 MU respectively.

DISCOMs and ERCs often do not account for sales migration while forecasting demand in the tariff determination process, even though DISCOMs have lost substantial sales to open access and captive sources. Table 3.3 shows the sales growth rates projected by DISCOMs for the HT (High Tension) Industrial consumer category which has faced considerable sales loss due to open access and captive options in the past. The instances documented clearly show that the recent fall in sales growth has not been considered while projecting demand in this category.

Table 3.3: Instances of high sales projection for HT industrial consumers

DISCOMs in:	Instances of high sales projection for HT industrial consumers
Rajasthan	The average annual sales growth rate from 2010-11 to 2013-14 was 2.9%. However, to estimate sales for 2014-15, the commission assumed a much higher growth rate of 6.48% (which is based on the CAGR of sales from 2008-09 to 2013-14) (RERC, 2015b).
Maharashtra	The sales growth assumed for HT Industrial consumers for the year 2015-16 was 7%. This is in spite of the growth in sales between: • 2013-14 and 2014-15 being 4.84% (MERC, 2016) (MERC, 2015d) • 2012-13 and 2014-15 being negative at -3.45% (MERC, 2014b) • 2010-11 and 2014-15 being negative at -1.6% (MSEDCL, 2012) The Commission justified such an increase despite increasing open access 'in view of the fact that revival of economic and industrial growth with increased availability of power is expected to reflect in higher growth rate of industrial consumption.' (MERC, 2015a, p. 107) For the year 2016-17, MERC explicitly used the combined growth rate of open access sales as well as industrial category sales to project demand. This is in the hope that 'Make in Maharashtra' and industrial subsidies will revive DISCOM sales (MERC, 2016).
Madhya Pradesh	In the tariff petitions for 2012-13 to 2016-17, three year, four year and sometimes even nominal growth rates have been considered by the DISCOMs for the projections without explanations for the same, which have been approved by the ERC. For 2016-17, the DISCOMs projected a 7.65% increase in HT industrial sales even though sales in that category grew only by 3.1% between 2014-15 and 2015-16 (MPPMCL, 2016).
Punjab	As per DISCOM estimates, the sales growth between: • 2014-15 and 2015-16 was negative at -2.44% • 2012-13 and 2015-16 was 4.2%. The projection for 2016-17 assumes a growth in sales of 7.26% (PSERC, 2016c) . This higher growth rate was justified 'in view of sufficient generation capacity available with PSPCL to meet the energy demand during whole of the year' (PSERC, 2016c, p. 153).

Source: Various regulatory orders and petitions.

Thus, as the title of this section indicates, sales migration is not the major driver for substantially increased backing down and surplus capacity. This necessitates careful analysis of issues with demand estimation and capacity addition which are discussed in Section 3.2.

3.2 Capacity addition: Convenient past and uncertain future

Between 2012–13 and 2015–2016, India added about 80,180 MW of thermal power capacity (CEA, 2017). This addition is about 60% more than the thermal capacity in 2011–12 and is 10% higher than the target capacity addition for the 12th Plan period (2012-17). In 2011–12, the All India Peak Demand was 1,30,006 MW and by 2015-16 it was 1,53,366 MW, increasing by 18%. Undoubtedly, the capacity addition in the recent past is much more than the growth in peak demand and has played a significant role in the sustained surplus before DISCOMs today.

Capacity addition by DISCOMs is planned on the basis of projections of future demand growth. For over a decade, several SERCs have had regulations and guidelines for planning power procurement which call for long-term and medium-term demand forecasts. Several DISCOMs also have separate demand estimation exercises while planning for capacity addition. Section 3.2.2 to Section 3.2.8 will discuss state-wise demand estimation processes and efforts and trace the capacity addition that it necessitated.

As on January 2017, 71,406 MW of thermal capacity are under construction and are likely to be commissioned in the near future. By 2022, India is also planning to achieve its target of adding 175 GW of power from renewable energy sources. This capacity addition target itself is more than half the current installed capacity in the country. Most of this capacity is to be contracted by DISCOMs even though sales migration will reduce demand. The capacity addition and demand growth trends imply that DISCOMs are setting themselves up for further increased surplus. The state-wise implications of capacity in the pipeline are also discussed in the following sections.

Before discussing the experience in various states, we would like to first discuss issues with the demand estimation methodology adopted by the Central Electricity Authority (CEA). This is because CEA demand estimates, especially medium and long-term estimates published under the Electric Power Survey (EPS) are heavily relied on by the state DISCOMs and ERCs for forecasting demand to assess need for capacity addition. Moreover CEA forecasts are also used by central sector generation and transmission utilities while investing in new capacity.

3.2.1 Demand estimation by CEA

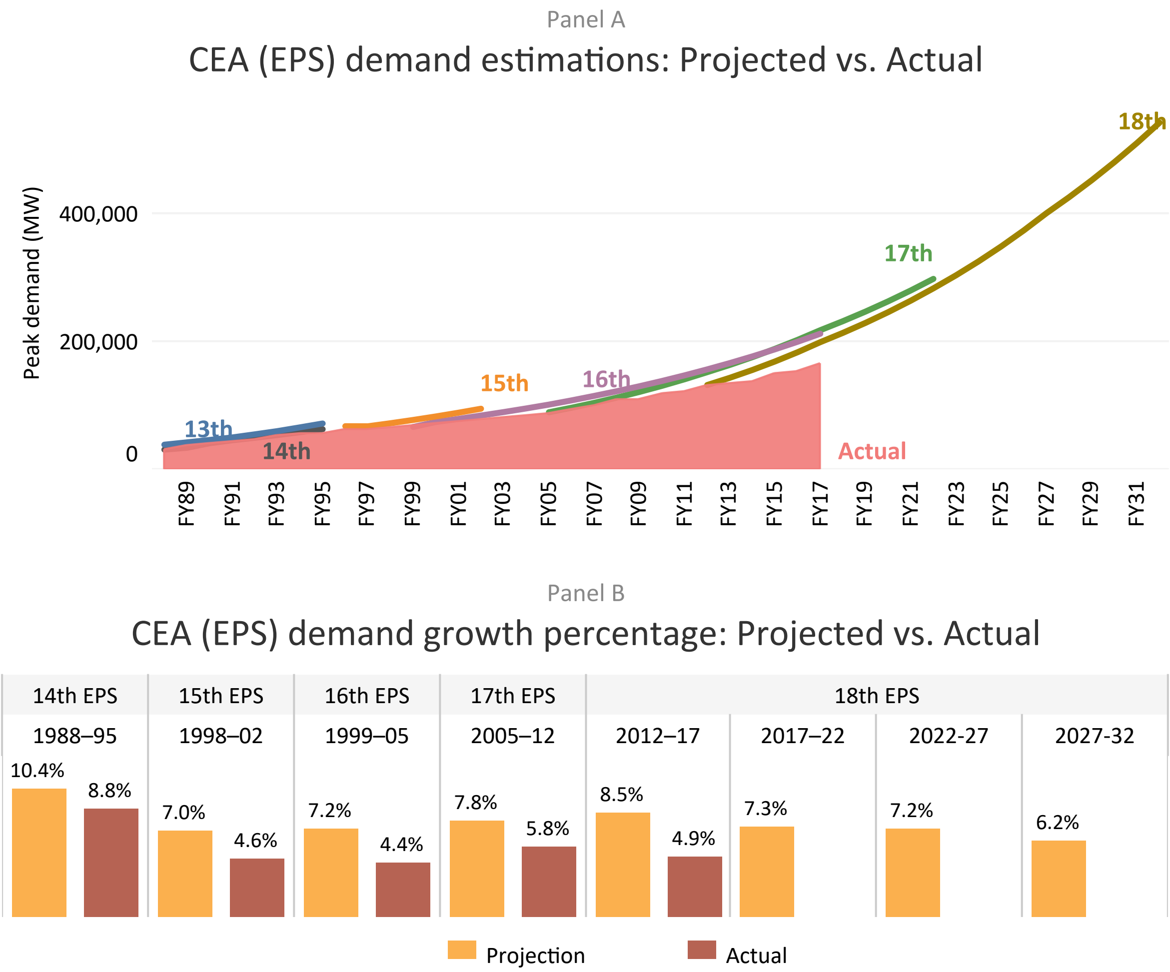
In order to aid planning, the Central Electricity Authority (CEA), publishes medium and long-term demand estimates on a periodic basis as part of the Electric Power Survey (EPS). Up until 1982, these estimates were published on an annual basis. Thereafter, the forecast was published every five years congruous with the national Five Year Plans. The EPS forecasts annual electricity demand for five years on an annual basis based on Partial End Use Method. It also projects demand on five-yearly basis for the next 10 to 20 years based on trend analysis and extrapolation. In addition to the EPS, the CEA's Load Generation and Balance report estimates the demand and energy requirement for the upcoming year in order to ascertain the power supply position.

The CEA also publishes the National Electricity Plan as mandated in the Electricity Act, 2003 to assess the generation and transmission capacity requirement to meet the demand for the next 10 years for the country. The National Electricity Plan depends on the CEA EPS demand forecasts to assess investment and infrastructure requirements in the sector.

While forecasting demand for assessing future power requirements, the ERCs and utilities are guided by the EPS estimates. The Electricity Act, 2003 encourages DISCOMs to undertake bidding for power procurement and the central government has notified guidelines for this purpose. As per an amendment to these guidelines, demand forecasts for procuring power via bidding 'shall be based on the latest available (at the time of issue of Request for Proposal) Electric Power Survey published by Central Electricity Authority' (MoP, 2005). Due to this specification in the guidelines, most competitively bid private capacity was added on the basis of EPS forecasts. Additionally, some ERC regulations also specifically mention that DISCOMs should be guided by the methodology and estimates adopted in the EPS.

Figure 3.2 shows the variation between EPS projections and the actual demand growth from the 13th EPS which has estimates from 1989.The 18th EPS, the most recent, uses 2009-10 as the base year to project demand annually till 2021–22 and for every five years till 2032. Panel A of Figure 3.2 clearly shows the consistent over-estimation of peak demand from the 13th EPS to the 18th EPS. Panel B shows that the growth rates for peak demand in every round have been ambitious. In fact, from the growth rates in Panel B, it is evident that it was mostly revision of the base with every new EPS round that helped temper the peak demand projections. Evidence from over 20 years shows that actual demand growth has been much less and more or less consistent at about 5%. Yet, the assumed growth rates continue to be 20% to 30% higher at 7% to 8%. Lack of regular revision of estimates given changing circumstances also contributes to overestimation.

Figure 3.2: CEA demand projections across various EPS rounds[29]



Source: PEG analysis based on projections from various EPS rounds and actual peak demand reported by CEA

The draft National Electricity Plan (NEP) prepared by the CEA was released in December 2016 for public comments before finalisation. The report has been making headlines as it projects 20% lower peak demand for 2026-27 than the 18th EPS. Consequently, it also projects no additional coal-based capacity addition requirement till 2022 (CEA, 2016e). The draft NEP estimates also assume about the

[29] Peak demand numbers for 2016–17 are based on CEA estimates in the load generation and balance report. The growth rates considered in Panel B reflect the growth rates between the years 1988–98 to 1994–95 for the 14th EPS period and so on.

same growth rates as the 18th EPS and the reduction in projected demand can be attributed to the use of a later base year for projections. Even with these growth rates, the draft NEP recognised the need to stop further coal capacity addition, which is significant. However, these observations and estimates are subject to change after due consultation and the release of the 19th EPS.

The consistent over-estimation of CEA demand has been noted by several commentators for many years (Purkayastha, 2001).In fact, S.L Rao, a former Central Electricity Regulatory Commission (CERC) chairperson has also famously noted that:

"Forecasts by the CEA have invariably exaggerated demand. They have been based on projections of current demand with the addition of new projects expected to come into operation." (Rao, 2002).

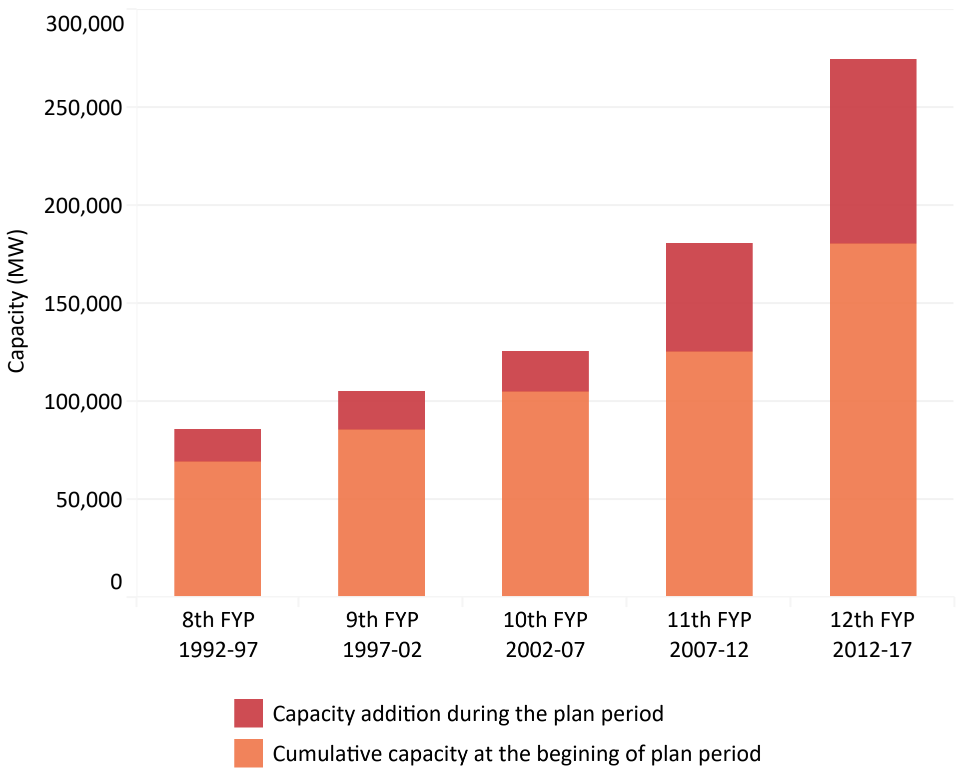
In addition, CEA demand estimates till recently have paid less attention to reduction in demand due to energy efficiency and conservation efforts. Moreover, the method used for forecasting demand, especially on an annual basis has been said to not adequately capture uncertainty, randomness and seasonality (Rallapalli & Ghosh, 2012). The peak demand numbers used by the CEA have also been questioned in the past as there is a variation between actual peak demand numbers reported by POSOCO, the national systems operator and the CEA (CEA, 2016a) (POSOCO, 2016). The CERC in the past has also identified the use of peak demand to forecast capacity requirement as problematic as such estimates only capture '*instantaneous demand and not sustained demand*' (CERC, 2014). Given seasonal and daily variations in demand, planning vanilla base load capacity addition based on peak demand seems like a perfect recipe for off-peak surplus capacity. With the advent of open access, captive options, falling renewable energy prices, sales migration implies that the state demand is not the same as the DISCOM demand. Therefore relying on EPS projections for the state to plan power procurement for the DISCOMs facing sales migration puts the utility square on the path to surplus.

The current surplus has also been attributed to a recent fall in demand due to economic slow-down and industrial growth. From Panel B of Figure 3.2 it is clear that though the rate of demand growth in the recent years has reduced, this reduction is marginal. However, as the actual demand consistently falls short of projected demand, it more likely that the demand didn't grow as anticipated and contributed to the surplus.

Overestimation of demand at this juncture has serious implications given that for the first time in many decades, the DISCOMs are witnessing significant excess capacity and substantial sales migration.

The CEA demand estimates are not solely responsible for the surplus. The rapid increase in capacity addition in the recent past is also a major reason. This is clear from Figure 3.3.

Figure 3.3: Growth in installed capacity over plan periods



Source: (CEA, 2017b) (CEA, 2016d)

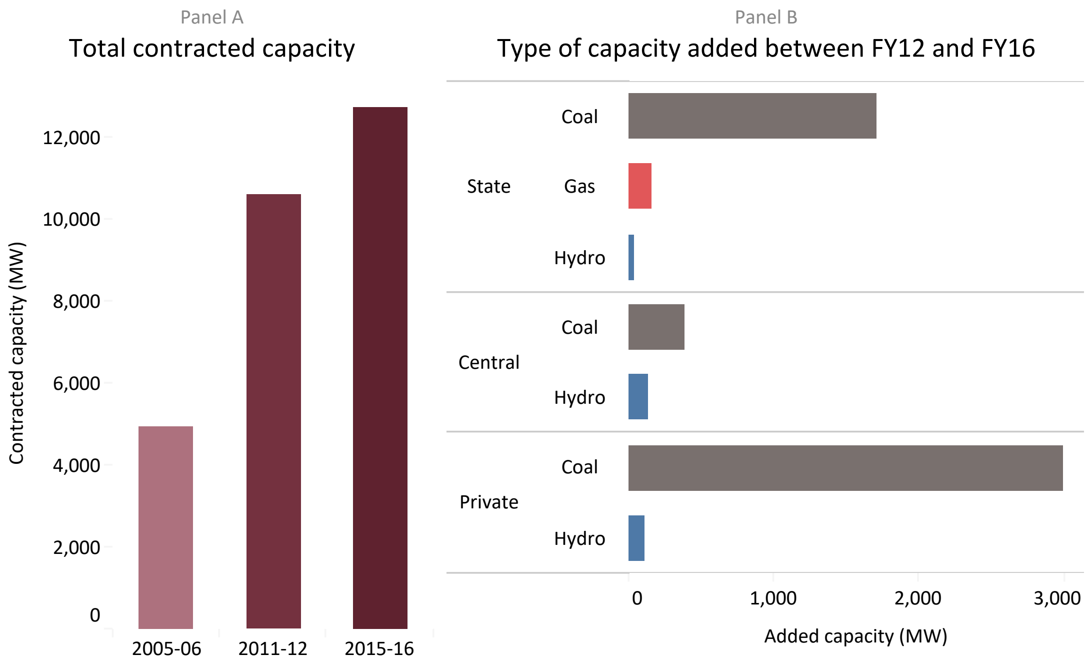
Figure 3.3 clearly shows that the capacity addition in the 12th Five Year Plan till January 2017 was 70% higher than the capacity addition in the 11th Five Year Plan period which was 160% higher than the capacity addition during the 10th Five Year Plan. The CEA overestimated demand in the earlier plan periods as well but it was only in the past decade that capacity addition increased rapidly. This is mostly due to the ambitious capacity addition planned. Even without accounting for renewable energy, the capacity addition planned in the past 3 five year plans would have resulted in total installed capacity being in excess of relevant EPS demand estimates. The estimates would have exceeded EPS by 32% at the end of the 10th Five Year Plan and 34% each at the end of the 11th and 12th Five Year Plan. Therefore a combination of overestimation of future demand as well as poor capacity addition planning has resulted in surplus power in many states. Significant amount of this capacity was contracted by DISCOMs in the past decade. The rationale given for contracting capacity and process followed while planning capacity addition is discussed in the following sections.

3.2.2 Rajasthan

The Rajasthan ERC's 'Power purchase and procurement process of distribution license' regulations (2004) state that DISCOMs should project demand for 5 years and 10 years into the future on an annual basis. As per the regulations, the state Energy Assessment Committee (EAC), consisting of Chairman and Managing Directors of the DISCOMs, RVUN, SLDC and the State Transmission Utility (STU) are to finalise the power purchase requirement, based on these estimates, (RERC, 2004). The committee was constituted in 2011, seven years after the regulations were notified. Nevertheless, this committee played a vital role in estimating future demand increase which necessitated significant capacity addition in Rajasthan.

Figure 3.4 below indicates the growth in non-renewable capacity procured by Rajasthan DISCOMs in the past decade (Panel A). Excluding renewables, the installed capacity has increased by about 115% between 2006 and 2012, and by 20% in the next five year period. Panel B shows the fuel-wise, ownership-wise capacity contracted by DISCOMs between 2012 and 2016. From Panel B it is clear that in the past five years, significant amount of this capacity has been coal-based and the majority has been contracted from the RVUNL and private generators.

Figure 3.4: Growth in contracted capacity in Rajasthan



Source: PEG analysis based on regulatory submissions and orders.

Besides this, the contribution of renewable energy generation also grew from 1,036 MU in 2005–06 to 6,067 MU by 2015–16.

Most of this capacity addition was approved by the Energy Assessment Committee (EAC) and was based on assessment of future demand and supply. Describing one such process which is responsible for the private capacity addition between 2012 and 2016 can highlight issues in power procurement planning approaches adopted by the state.

In 2008, the DISCOMs sought RERC's approval for power procurement on a long-term basis (for a period of 25 years) via competitive bidding. To arrive at this shortfall, DISCOMs projected demand for 2016-17 as per the 17th EPS long-term growth rates. The ERCs assessed this projection independently using forecasts based on 10-year monthly demand data (accounting for load shedding) which was submitted by the DISCOMs. The ERC analysis of the monthly data showed that the power requirement during peak months was substantially higher than lean months. Contracting RTC power for this seasonal peak deficit would imply surplus power, but the DISCOMs were confident of managing this through sale of power or banking. They also requested for procurement of excess capacity of 300 MW in order to mitigate shortfall in case of delays and cancellation of projects.

Based on an assessment of available and upcoming capacity, the ERC identified a shortfall of 1,716 MW by 2016–17. 1,320 MW of this was proposed to be met via competitive bidding (Case 2). As per the ERC's estimates, the remaining deficit would translate to an installed capacity requirement of 988 MW.[30] The ERC also felt that an additional 780 MW should be added to meet the spinning reserve requirement as per the National Electricity Policy, 2005. Over and above this, the ERC also added a 300 MW requirement to offset the risk of delays in capacity addition. Therefore the shortfall of 1,716 MW was proposed to be met with power procurement of 3,320 MW. Of the 3,320 MW, 1,000 MW was to be procured for peak months, i.e. October to March alone. It interesting to note that the Commission preferred to approve seasonal contracts rather than rely on future sale of potential surplus to avoid the likelihood of consumers being saddled with costs due to backing down (RERC, 2008). Based on this approval, DISCOMs were able to contract 1,200 MW of power from Adani Power Rajasthan Limited's power plant at Kawai. This is 200 MW in excess of the commission approved quantum, but was justified on the basis of the imminent shortages due to slippage and delay in commissioning of other upcoming capacity (RERC, 2010).[31] The procurement of 1,000 MW of seasonal power was not successful due to a lack of bidders, and by 2011 the procurement of 1,320 MW was delayed due to issues with coal linkages.

In 2011 the utilities sought fresh approval for the procurement of 2,250 MW (RERC, 2011a). The demand estimation for this process was not based on the EPS but on the estimations of the ERC, calculated from past sales growth. The demand projected for 2017–18 was 15,873 MW. This was grounded on the assumption of increased hours of supply to agriculture, high growth in domestic consumption, and increased commercial and industrial demand due to the upcoming Delhi Mumbai Industrial Corridor and the Golden Quadrilateral (RERC, 2011b). Based on increased hours of supply to agriculture, the RERC projected that demand would increase by about 21% in 2012–13, after which demand would growth at a high annual rate of 9.75% per year. The RERC projected capacity availability of 16,653 MW by 2017–18, which is already higher than the demand projected (15873 MW). This was justified on the basis spinning reserve requirement (1,745 MW) as well as delays in commissioning or non-fructification of capacity, especially due to difficulties in obtaining coal linkages. DISCOMs submitted that about 2,900 MW of state-owned generating capacity (all waiting for coal linkages) is likely to be delayed or cancelled. As of 2017, most of these projects are still in the pipeline. The commission approved an additional purchase of 1,320 MW to account for slippages. The capacity requirement of 1,394 MW (almost the same as the margin identified for slippage) was arrived at based on these assumptions.

As there was no interest for seasonal contracts from the earlier approval, the Commission decided to withdraw the approval of 1,000 MW for peak months via Case 1. In its stead, it approved procurement of 1,000 MW via Case 1 or Case 2 bidding on an RTC basis, and 250 MW from Unit 3 and 4 of Giral Lignite TPS at Barmer. In 2014, the Commission reassessed the requirement of electricity based on recommendations of the EAC and the state government (and despite objections of successful bidders for the procurement of 1,000 MW) revised the power procurement requirement from 1,000 MW to 500 MW. Accordingly, 250 MW each was procured from Maruti Clean Coal and Power Limited and DB Power Limited at ₹ 4.51/kWh and ₹ 4.81/kWh respectively

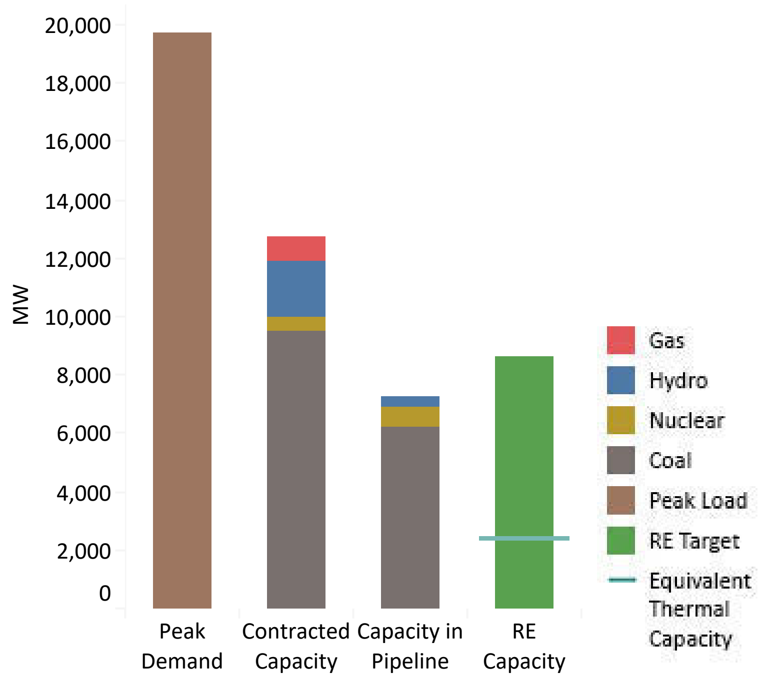
[30] Considering 8.5% auxiliary consumption 4.4% losses within the State and 85% availability.
[31] The DISCOMs reported that about 1,395 MW of capacity would be delayed which could result in shortages .As the plants considered to estimate this quantum were not listed, it is difficult to ascertain if the plants did come online later.

(RERC, 2015a). Though late, the state's decision to revise the power procurement requirement is a step in the right direction.

The estimation of future power requirement was challenging without a comprehensive review of capacity in the pipeline (especially of RVUNL's capacity) and weeding out of perpetually delayed projects.

The DISCOMs of Rajasthan have significant capacity in the pipeline. This is true for base-load thermal capacity as well as renewable energy capacity addition. By 2022, Rajasthan DISCOMs would add about another 7,285 MW of thermal capacity, 74% of which will be RVUNL capacity. Rajasthan has also committed to adding 5,762 MW of solar and 8,600 MW of wind by 2022. Figure 3.5 depicts fuel wise capacity in the pipeline, expected to come online by 2022 juxtaposed with the current fuel-wise installed capacity as well as the peak demand projected in the 18th EPS for 2022. It also depicts renewable capacity addition assuming only part (60%) of the renewable energy target for the state as per national target for 2022 is achieved. Renewable energy is variable by nature, with lower plant load factors than thermal capacity. To reflect this, the bar for RE capacity addition also shows equivalent thermal generation capacity, denoted by a horizontal line. This is calculated considering CUF of 19% for wind power and 18% for solar power, and a PLF of 80% and auxiliary consumption of 8.5% for equivalent thermal capacity.

Figure 3.5: Capacity addition in the pipeline expected by 2022 in Rajasthan



Source: PEG analysis based on station-wise, contract-wise information available from regulatory orders, petitions and CEA reports and State Government documents.

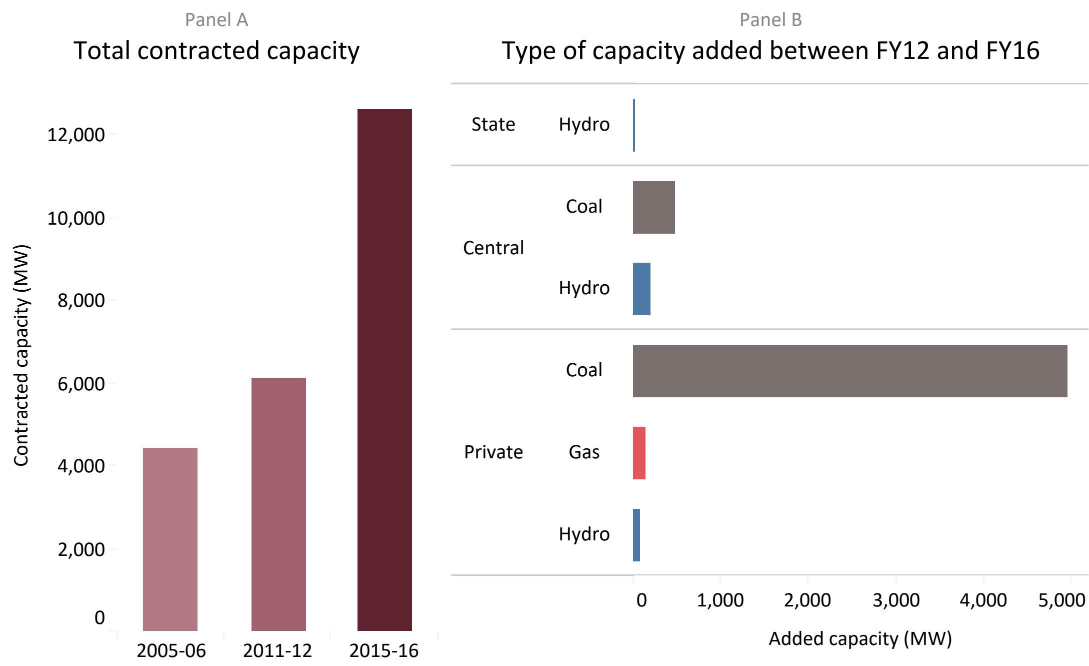
Even though the capacity addition is not as ambitious as earlier years, it is still significant. With the possibility that the actual demand will be lower due to overestimation and increased sales migration (especially with falling renewable energy prices), it is likely that the extent of surplus will be higher. It is also clear that surplus power will continue to be a medium to long-term issue for Rajasthan.

3.2.3 Punjab

The Punjab ERC's 'Power purchase and procurement process of distribution license' Regulations (2012) states that DISCOMs should ensure month-wise projections for demand and energy requirement 10 years on an annual basis. Such projections are to consider economic growth, effects of captive, open access sales migration and impact of the Demand Side Management (DSM) efforts. The estimations are to also account for variations due to agriculture load which is substantial in the state (PSERC, 2012). As per the regulations, demand forecasts should be guided by EPS methodology. Most of the capacity addition in the state took place before 2012 based on the ERC approved assessment of future demand and supply.

Figure 3.6 below indicates the growth in non-renewable capacity procured by PSPCL in the past decade. The installed capacity has increased by about 38% between 2005–06 and 2011–12 and by 106% between 2011–12 and 2015–16, as shown in Panel A. The contribution of renewable energy generation also increased from 233 MU in 2005–06 to 1,470 MU by 2015–16. As Panel B shows, significant amount of this capacity added in the recent past has been coal-based and that 88% of the capacity added has been contracted from private generators. As the privately owned capacity at Talwandi Sabo, Nabha and the Goindwal Sahib Power Plant account for about 66% of the capacity added in the last five years, this section will focus on the processes before the addition of these frequently backed down plants.

Figure 3.6: Growth in contracted capacity in Punjab



Source: PEG analysis based on regulatory submissions and orders.

In 2005-06, Punjab was reeling under severe shortages with a peak deficit of 20.3%. In order to address this, in the same year, the erstwhile Punjab State Electricity Board approached the Commission for the approval of 1,000 MW of capacity addition, projecting a deficit of 4,941 MW by 2011-12 based on the 16th and draft 17th EPS estimates. To make the case for procurement, in 2007, the ERC cited the rising prices of short-term bilateral trade, the commitment espoused in the National Electricity Policy (which requires that states ensure that there is no energy and peak shortage and availability of adequate reserves to provide electricity to all by 2012) and the anticipation of higher economic growth. At this time, the projected deficit for 2011–12, using 17th EPS estimates, was revised to 2359 MW. The PSERC also felt that delays in execution of projects and inefficiencies in existing plants would necessitate additional power procurement. Aggressive power procurement from private sources was also justified as the utility was not adding new capacity and the state relied heavily on central sector power at the time. (PSERC, 2007b).

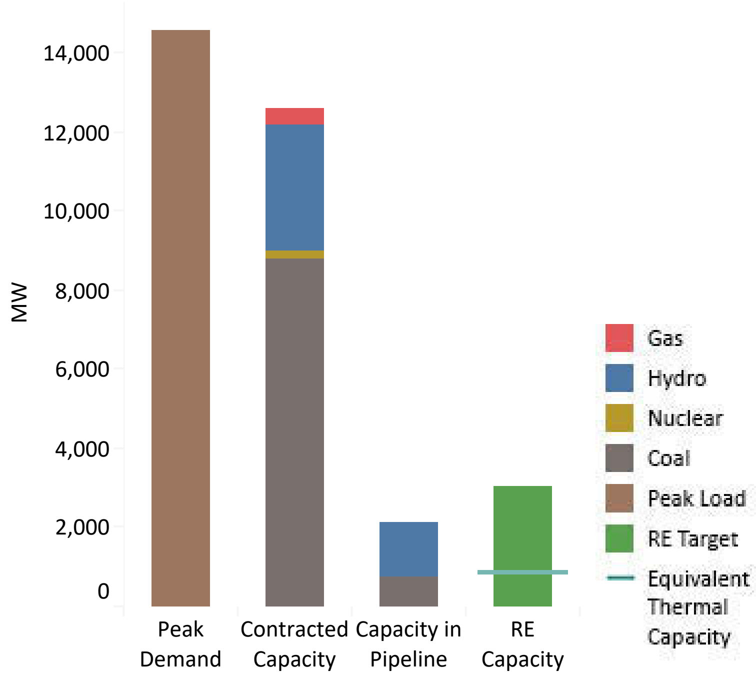
In 2007, PSERC allowed procurement of 2,400 MW - 1,200 MW of coal-based power from the TPP at Talwandi Sabo and another 1,200 MW of coal-based power from the TPP at Nabha (PSERC, 2007a). In 2008, the Talwandi Sabo TPP sought approval to enhance capacity from 1,200 MW to 1,980 MW. The Commission projected peak demand for 2015–16 to be 15,385 MW, assuming peak demand to grow by 8.75%. This was the growth rate used by the CEA in the 17th EPS for projecting demand from 2006–07 to 2011–12. This growth rate was used instead of the annual peak demand growth rate estimates (5.59%) to project demand for 2016-17 in the 17th EPS (CEA, 2007b). By assuming 8.75% as the growth rate, despite EPS projections, the Commission was able to project a deficit of 1,711 MW instead of 173 MW. This estimate helped justify the enhancement of capacity sought by Talwandi Sabo TPP (PSERC, 2008). Thus, Talwandi Sabo TPP and NPL Nabha TPP, which account for more than one-quarter of the installed capacity of PSPCL in 2015–16, were procured. The Talwandi Sabo TPP and the Nabha TPP were expected to come up by 2011–12, but the plant was fully commissioned only in March 2016 and July 2014 respectively. The initial Power Purchase Agreement (PPA) for the Goindwal Sahib TPP was signed in 2000 and the revised MoU was signed in 2006. After several issues with fuel availability, capital costs and project execution and delays, the plant was finally commissioned more than a decade later in 2016. It is possible that if these projects were commissioned on time, they could have increased backing down.

Between 2016–17 and 2021–2022, Punjab DISCOMs are to add another 2,139 MW[32] of capacity. PSPCL is also making significant efforts to surrender existing central sector power but about 60% of the capacity in the pipeline is from central sector generating stations. Capacity in the pipeline also includes plants like Karcham Wangtoo Hydro-Electric Project (HEP) and the Udupi Power Corporation plant, where power supply has been delayed for long and costs have escalated. The DISCOM is looking for viable options to surrender the power. Punjab is also committed to adding 4,772 MW of solar, 50 MW of small hydro-power and 244 MW of biomass-based power by 2022.

Figure 3.7 illustrates the extent of capacity in the pipeline assuming that about 60% of the renewable energy target is achieved by 2022. It is clear that the capacity planned in the pipeline is less ambitious than the past and might reduce further if PSPCL is able to surrender PPAs. Moreover there is a high likelihood that all of this capacity will be online by 2022. Compared to the existing contracted capacity and the projected (probably overestimated) demand, the capacity in the pipeline is still significant and the gap will increase with sales migration.

[32] This considers capacity that has already been added after 31st March 2016 as capacity in the pipeline. For consistency and comparison, the installed capacity considered is as on 31st March 2016. About 44 MW contracted from Vishnugad HEP commissioned in 2016 is considered in the pipeline.

Figure 3.7: Capacity addition in the pipeline expected by 2022 in Punjab[33]



Source: PEG analysis based on station-wise, contract-wise information available from regulatory orders, petitions and CEA reports and State Government documents.

3.2.4 Maharashtra

Maharashtra is one of the states with the highest contracted capacity and this is due to the significant capacity addition by MSEDCL in the recent past. For every additional capacity addition, it would have a separate exercise for demand projection before the ERC, often based on CEA EPS estimates. As per the tariff regulations of 2005, DISCOMs were to submit five-year rolling demand projections on an annual basis for the commission's approval (MERC, 2005a).The recently notified Multi-Year Tariff (MYT) regulations of 2016 specify that the DISCOMs are to project unrestricted base and peak load for five and ten years on an annual basis which is subject to ERC review (MERC, 2015b). Consequently the DISCOMs have been reporting long-term forecasts for base and peak load.

Figure 3.8 below indicates the growth in non-renewable capacity procured by the MSEDCL in the past decade. The installed capacity has increased by about 88% between 2005–06 and 2011–12, and by 24% between 2011–12 and 2015–16 as shown in Panel A of Figure 3.8. Panel B shows that in the past five years, significant amount of this capacity has been coal-based and 60% has been contracted from private generating plants via competitive bidding. MSPGCL has contributed to 27% of the

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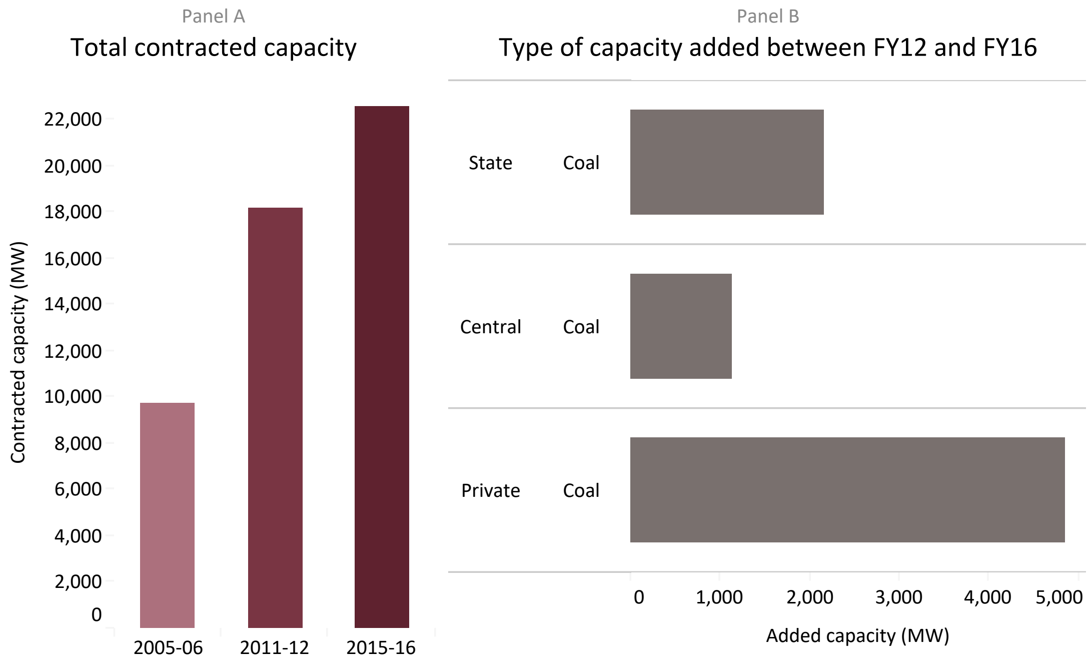
[33] Figure depicts fuel wise capacity in the pipeline expected to come online by 2022 juxtaposed with the current fuel-wise installed capacity as well as the peak demand projected in the 18th EPS for 2022. It also depicts renewable capacity addition assuming only part (60%) of the renewable energy target for the state as per national target for 2022 is achieved. Renewable energy is variable by nature, with lower plant load factors than thermal capacity. To reflect this, the bar for RE capacity addition also shows equivalent thermal generation capacity, denoted by a horizontal line. This is calculated considering CUF of 19% for wind power and 18% for solar power, and a PLF of 80% and auxiliary consumption of 8.5% for equivalent thermal capacity.

increase in installed capacity in this period. Besides this, the contribution of renewable energy generation also increased from 510 MU in 2005–06 to 8,544 MU by 2015–16.

Figure 3.8: Growth in contracted capacity in Maharashtra



Source: PEG analysis based on regulatory submissions and orders

In 2006, facing acute shortages, the MSEDCL filed a petition for the approval of 4,000 MW power procurement (850 MW RTC power, 2,250 MW from 06:00 to 23:00 hrs and 900 MW from 07:00 to 11:00 hrs and 17:00 to 22:00 hrs). However, despite previous directives, the MSEDCL did not submit a comprehensive demand forecast or a five-year power procurement plan and only submitted projections for 2011–12. The MSEDCL relied on EPS estimates to forecast base, intermediate and peak load requirements, even though the 16th EPS reports only peak and energy requirements (MERC, 2007a). In light of this, the MERC approved procurement of only 2,000 MW and directed MSEDCL to submit a detailed demand forecast prepared by an expert committee and a capacity addition plan which can be considered for further approvals. This is important as the MSEDCL in its petition did not consider capacity addition of 1,500 MW, which MSPGCL was planning to commission before 2011–12 (MERC, 2005b) and over 6,000 MW contracted via MoUs from eight private companies in 2005 (BS, 2005).

The MSEDCL, which was relying of the 16th EPS estimates for projections, appealed against this order before the APTEL claiming that the ERCs did not have the power to direct MSEDCL (which was complying with the competitive bidding guidelines) to conduct a demand forecast exercise. The MSEDCL claimed that capacity addition is an immediate and paramount requirement due to rampant load shedding and impeded industrial growth. The APTEL ruled in the MSEDCL's favour (MERC, 2007b). According to the standard bidding guidelines, approval from the commission is necessary only if the capacity to be procured exceeds the demand forecast for three years following the commencement of supply from contracted capacity. Thereafter, in accordance with the guidelines, MSEDCL would seek the Commission's approval only in the case of deviations from standard bidding guidelines. In 2008, MSEDCL wanted to procure an additional

5,200 MW of power and while seeking approval for this; it also mentioned that such procurement could result in surplus in the monsoon months. As the guidelines mention the need for ERC approval in case of annual surplus and not seasonal surplus and as MSEDCL had '*devised a strategy to manage the surplus*', no assessment of demand and supply was subject to regulatory approval (MERC, 2008).With the failure of the previous call for seasonal bids, the power procurement approved were for RTC contracts alone.

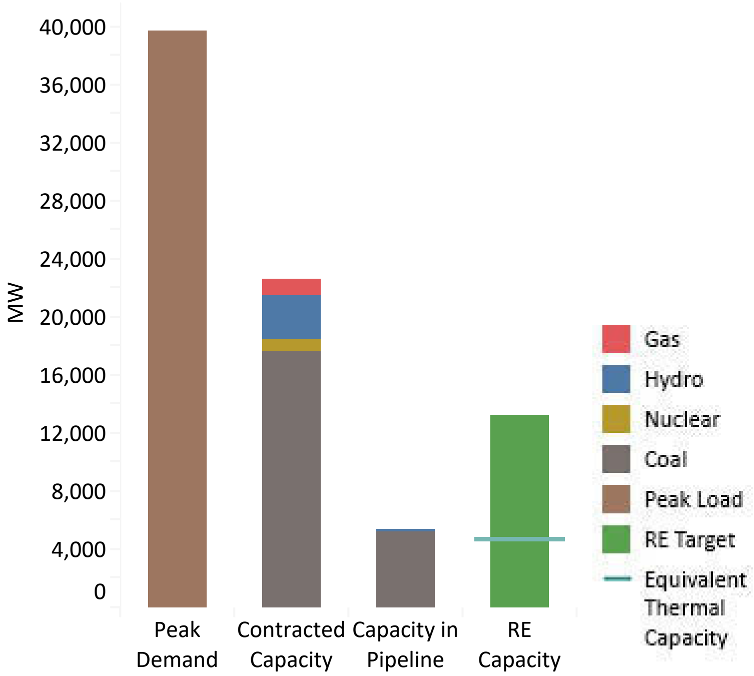
By 2008, the MSEDCL signed PPAs for 1,320 MW capacity from Adani Power Maharashtra Limited (APML) and 680 MW from Lanco Kondapalli Power Limited. Due to uncertainties with the commissioning of the latter project, MSEDCL also procured 300 MW of power from JSW Power Limited. Lanco Kondapalli Power Limited shifted location to Wardha but the plant has still not been commissioned. By 2010, the MERC approved procurement of 1,200 MW from APML, 200 MW from EMCO Energy and 1,200 MW from Rattan India (formerly India Bulls). In addition to this, by 2011, the MSPGCL added 1,000 MW at Paras and Parli and planned to add 13,940 MW in the near future (MSPGCL, 2011). Of the listed projects in 2011, all but 600 MW have been shelved. In 2011, the MERC approved the procurement of an additional 125 MW from APML, and in 2012 the MERC approved procurement of an additional 440 MW from APML and 650 MW from Rattan India. In its petition for this approval, the MSEDCL projected surplus power between 2012 and 2016 based on an assessment of demand at supply. Despite this, the purchase was justified on the possibility of slippage or non-materialisation of plants considered in the pipeline and to manage demand given the retirement of certain MSPGCL units. It was also justified to safeguard against the unlikely eventuality that demand growth would shoot up to 10% instead of the 8% projected in the EPS (MERC, 2012b). A periodic comprehensive review of capacity addition and estimation of future demand could have provided a clearer picture of requirements and could have helped synergise capacity addition by MSPGCL with power procurement by MSEDCL.

Between 2015–16 and 2021–2022[34], the MSEDCL is to add another 5,434 MW of capacity. Unlike the past five years where private capacity addition dominated, 58% of the upcoming capacity will be from MSPGCL and 33% from central sector power plants. Additionally it is committed to adding 11,926 MW of solar, 7,600 MW of wind power, 50 MW of small hydro power and 2,469 MW of biomass-based renewable energy by 2022.

As shown in Figure 3.9, the capacity addition planned to be online by 2022 is less ambitious that in the past. However, given sales migration, reduced demand and ambitious assessments for demand growth in EPS, it is possible that even with reduced base-load addition; Maharashtra will continue to have surplus capacity. This predicament will be exacerbated even if only 60% of the renewable energy capacity addition targets are met.

[34] This considers capacity that has already been added after 31st March 2016 as capacity in the pipeline. Therefore capacity which has been commissioned after 31st March 2016 such as 500 MW from Chandrapur 8 and 600 MW each from Koradi 9 and Koradi 10 are considered as capacity in the pipeline.

Figure 3.9: Capacity addition in the pipeline expected by 2022 in Maharashtra[35]



Source: PEG analysis based on station-wise, contract-wise information available from regulatory orders, petitions and CEA reports and State Government documents.

3.2.5 Gujarat

Non-renewable capacity procured by Gujarat DISCOMs grew by 70% between 2005-06 and 2011-12, and by 18% between 2011-12 and 2015-16 as shown in Panel A of Figure 3.10. Panel B shows that in the past five years, about 71% of the contracted capacity was from privately owned coal-based plants. Besides this, the contribution of renewable energy generation also increased from 290 MU in 2011-12 to 5,694 MU by 2015-16. Power procurement and demand estimation for most of this addition was based on EPS estimates and DISCOM assumptions. In 2013, the GERC notified Guidelines for Procurement of Power by Distribution Licensees which specifies that the DISCOMs should submit a five-year power procurement plan on an annual basis, which should include demand and energy forecasts and assessment of energy availability. If the projected power supply position shows a deficit of more than 15% in the third year of the forecast, then the DISCOM should initiate medium-term procurement. If the projected supply position shows a deficit of more than 75% in the fifth year of forecast, then the DISCOM is to initiate long-term procurement (GERC, 2013).

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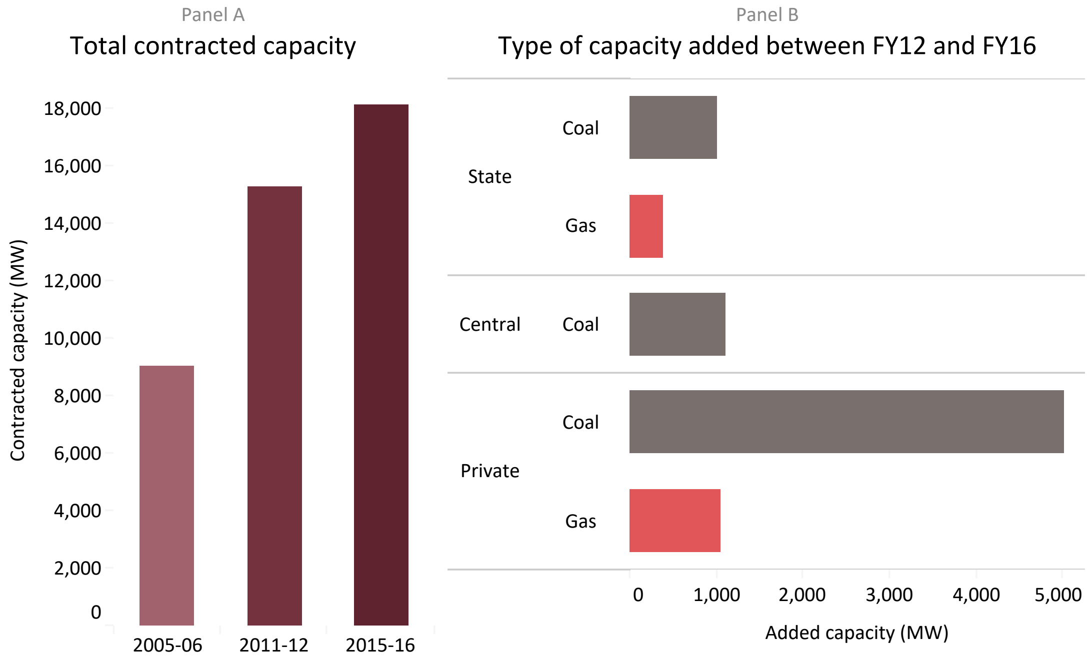
[35] Figure depicts fuel wise capacity in the pipeline expected to come online by 2022 juxtaposed with the current fuel-wise installed capacity as well as the peak demand projected in the 18th EPS for 2022. It also depicts renewable capacity addition assuming only part (60%) of the renewable energy target for the state as per national target for 2022 is achieved. Renewable energy is variable by nature, with lower plant load factors than thermal capacity. To reflect this, the bar for RE capacity addition also shows equivalent thermal generation capacity, denoted by a horizontal line. This is calculated considering CUF of 19% for wind power and 18% for solar power, and a PLF of 80% and auxiliary consumption of 8.5% for equivalent thermal capacity.

Unfortunately, these regulations were notified after much of the procurement had already taken place.

Figure 3.10: Growth in contracted capacity in Gujarat

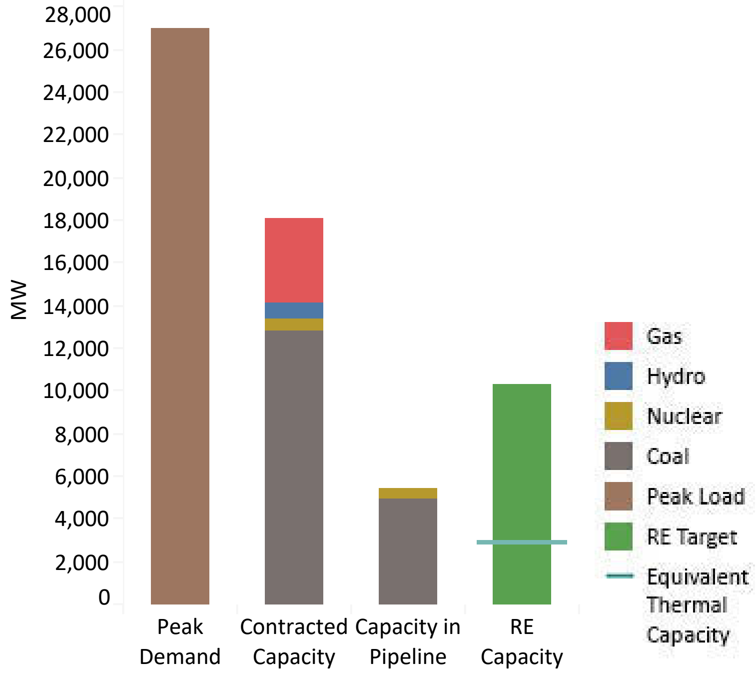


Source: PEG analysis based on regulatory submissions and orders

In 2007, the GERC approved the procurement of 3,200 MW noting that its less than the demand projected for 2011–12 and therefore does not deviate from provisions[36] of the competitive bidding guidelines (GERC, 2007). The DISCOMs signed PPAs to procure 2,000 MW from Adani Power Limited, 1,000 MW from Essar Power Gujarat Limited, and 200 MW from Aryan Coal Beneficiation Private Limited via competitive bidding. In 2009, when they petitioned the ERC for the approval of an additional 3,000 MW of power procurement via competitive bidding, the DISCOMs relied on the 17th EPS demand estimates to project demand for 2016–17. Assuming capacity recently contracted would be available by then and considering a 78% Plant Load Factor (PLF) of plants, the DISCOMs estimated a gap of 3,728 MW. The Commission accepted this method but used the normative 80% PLF to arrive at 3,022 MW to be approved for procurement (GERC, 2009). In 2010, based on the approval, the DISCOMs were able to procure 800 MW each from Shapoorji Pallonji TPP and Essar Power Gujarat Limited (EPGL) as well as 1,010 MW from KSK Mahanadi Power Company Limited. None of these three projects are likely to come online. Has these projects contributed to generation as per contract, the quantum of surplus would have been significantly higher. In the same time period, the GSECL also commissioned 500 MW at Ukai Unit 6 and 500 MW at Sikka Unit 3 and 4. Both of these plants are currently heavily backed down.

[36] According to GERC, the capacity to be procured did not exceed the demand forecast for three years following the commencement of supply from contracted capacity. Therefore the estimates were not subject to further scrutiny.

Figure 3.11: Capacity addition in the pipeline expected by 2022 in Gujarat[37]



Source: PEG analysis based on station-wise, contract-wise information available from regulatory orders, petitions and CEA reports and State Government documents.

By 2021–2022, the DISCOMs are expected to add another 5,421 MW[38] of capacity. Almost 60% of this capacity in the pipeline can be attributed to GSECL. Additionally Gujarat is committed to adding 8,020 MW of solar, 8,800 MW of wind power, 25 MW of small hydro power and 288 MW of biomass-based renewable energy by 2022. Figure 3.11 depicts capacity addition by 2021–22 for the states as against the peak load forecast for 2021–22 (18th EPS) and the installed capacity as on 2015–16. With the renewable energy capacity addition and with uncertainties with demand, supply in the future, though less than in earlier periods, will be much in excess of demand.

3.2.6 Madhya Pradesh

The MPERC's Power purchase and procurement process of distribution licensee regulations, notified in 2004 (and revised in 2006) calls for assessment of demand and energy requirement every year for a five-year period. Such assessment are supposed to include forecast of morning and evening peak periods as well as off-peak periods and must consider growth of captive generation and the impact of energy efficiency and impact of economic growth. It also expects DISCOMs to assess supply options based on present and future availability of existing contracted capacity, capacity addition in the pipeline as well as maintenance and retirement of plants. Based on assessment of demand and supply, DISCOMs are to present a least cost plan for power procurement to the ERC for review, failing which the Commission can impose penalties and initiate suo-motu proceedings (MPERC, 2006).

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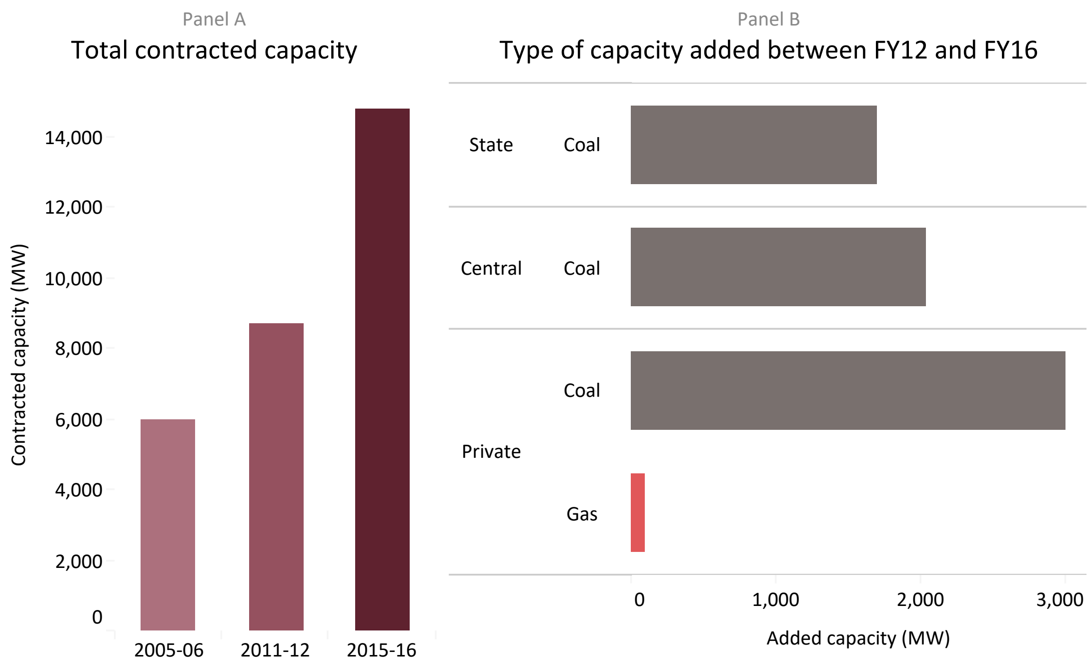
[37] Figure depicts fuel wise capacity in the pipeline expected to come online by 2022 juxtaposed with the current fuel-wise installed capacity as well as the peak demand projected in the 18th EPS for 2022. It also depicts renewable capacity addition assuming only part (60%) of the renewable energy target for the state as per national target for 2022 is achieved. Renewable energy is variable by nature, with lower plant load factors than thermal capacity. To reflect this, the bar for RE capacity addition also shows equivalent thermal generation capacity, denoted by a horizontal line. This is calculated considering CUF of 19% for wind power and 18% for solar power, and a PLF of 80% and auxiliary consumption of 8.5% for equivalent thermal capacity.

[38] Any contracted capacity commissioned after 31st March 2016 is considered to be in the pipeline. Thus 250 MW Bhavnagar Energy Unit 1 is considered in the pipeline even though it is commissioned.

Some instances from the capacity addition experience in Madhya Pradesh detailed in this section indicate that these regulations were never complied with and also discusses issues with the power procurement.

Figure 3.12 indicates the substantial capacity addition in the recent past where capacity between 2005–2006 and 2011–2012 has increased by 45% and capacity between 2011–2012 and 2015–2016 has increased by 70%. Panel B of Figure 3.12 shows that in the past five years, about 45% of the contracted capacity is from private plants and 35% the remaining from central and 25% from state sector plants. Besides this, the contribution of renewable energy generation also increased from 278 MU in 2011–12 to 2,211 MU by 2015–16.

Figure 3.12: Growth in contracted capacity in Madhya Pradesh



Source: PEG analysis based on regulatory submissions and orders

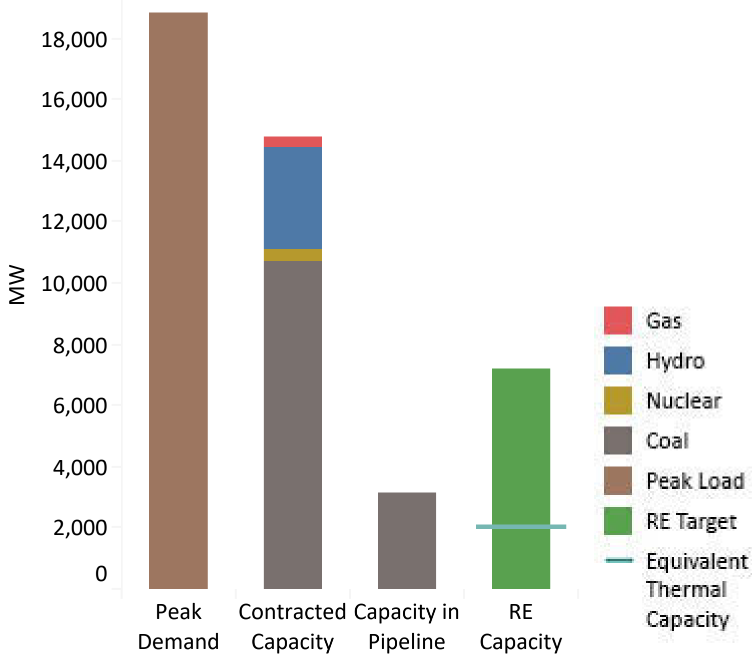
About half of the privately owned capacity added in the recent past are cost-plus projects (the other half being capacity contracted from the UMPP at Sasan via competitive bidding). In fact, majority of the power was contracted in January 2011, just before the date beyond which competitive bidding became mandatory for power procurement. Despite the regulations calling for regular assessment of demand and supply, there seems to be no assessment of demand and supply before these were approved. The commissioning of some of these plants has also been delayed significantly. Notable among this contracted capacity is the 554 MW from Jaiprakash Power Ventures Limited's (JPVL) plant at Bina and the 254 MW from Jhabua Power Limited's plant in Seoni. Both these plants are high cost and are projected to be backed down in 2016–17 by DISCOMs.

In the case of competitively bid projects, the DISCOMs projected supply was not in excess of demand for three years from the date of commencement as stipulated in the competitive bidding guidelines. As the commission would only assess deviations from the competitive bidding guidelines, the demand and supply estimations themselves were not scrutinised in detail. Periodic assessments of demand and supply as specified in the ERC regulations were also not conducted on a regular basis.

In 2011 the DISCOMs sought to procure medium-term power to ensure 24x7 electricity supply throughout the state. For this, 507 MW to 3,136 MW of power was needed for the periods April 2012 to July 2012 and September 2013 to March 2014. The need for this power was justified based on projections by the DISCOM. The commission approved this quantum but expressed concern over potential impacts of procurement. MPERC stated that the DISCOMs are free to procure any quantum of power in their capacity as traders. However, if the power purchased is billed as part of the utility business, impacts need to be assessed as part of the annual tariff process. Thus, the cost and the quantum are to be approved as part of the tariff process (MPERC, 2012).[39]

Madhya Pradesh DISCOMs also have significant capacity in the pipeline. Between 2016–17 and 2021–2022, Madhya Pradesh DISCOMs are planning to add about 3,107 MW of non-renewable capacity. About 42% of the capacity being contracted is from the MPPGCL and 45% is from central sector stations. Additionally, Madhya Pradesh has committed to adding 5,675 MW of solar, 6,200 MW of wind, 25 MW of small hydro-power and 118 MW of biomass-based power by 2022. Figure 3.13 shows that even though the DISCOMs in Madhya Pradesh have tied up far less capacity for 2022 than in the previous years, this would still imply that DISCOMs will face power surplus even in the medium-term, especially with uncertain demand.

Figure 3.13: Capacity addition in the pipeline expected by 2022 in Madhya Pradesh[40]



Source: PEG analysis based on various reports

[39] Assessments were also conducted on an annual basis to estimate and manage impacts of short-term power purchase. A petition to procure short-term power during the rabi season includes assessment of sales, capacity in the pipeline and the merit order of plants (MPERC, 2011).

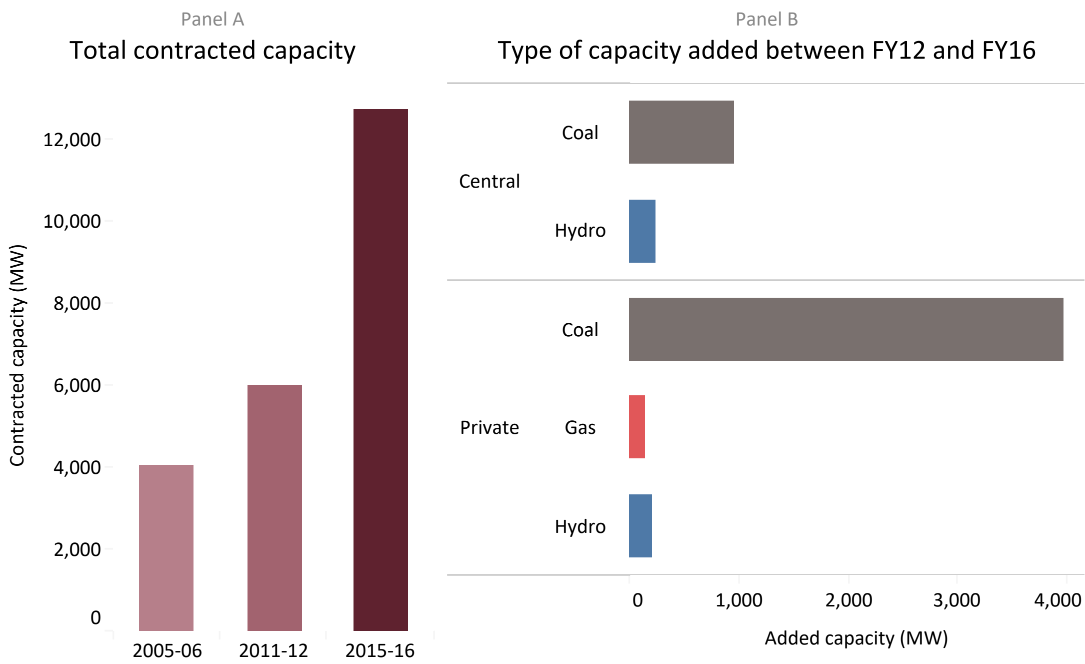
[40] Figure depicts fuel wise capacity in the pipeline expected to come online by 2022 juxtaposed with the current fuel-wise installed capacity as well as the peak demand projected in the 18th EPS for 2022. It also depicts renewable capacity addition assuming only part (60%) of the renewable energy target for the state as per national target for 2022 is achieved. Renewable energy is variable by nature, with lower plant load factors than thermal capacity. To reflect this, the bar for RE capacity addition also shows equivalent thermal generation capacity, denoted by a horizontal line. This is calculated considering CUF of 19% for wind power and 18% for solar power, and a PLF of 80% and auxiliary consumption of 8.5% for equivalent thermal capacity.

3.2.7 Haryana

The Haryana ERC's Guidelines for Load Forecast, Resource Plans and Power Procurement (1999) states that the Haryana Vidyut Prasaran Nigam Limited (HVPN) along with DISCOMs, HPGCL and the state government should formulate a 10 year least-cost power procurement plan every two years. As per the regulations, such plans should be based on category-wise load forecasts, assessment of current supply options, future availability, capacity addition in the pipeline, and maintenance and retirement of plants. However, capacity addition in the recent past was not made on the basis of such comprehensive power purchase plans (HERC, 1999).

Figure 3.14 indicates the growth in non-renewable capacity procured by Haryana DISCOMs in the past decade. The installed capacity grew by about 49% between 2005–06 to 2011–12 and by 84% between 2011–12 and 2015–16 as shown in Panel A. Panel B shows that in the past five years, about 78% of this capacity has been contracted from private coal-based generators. Besides this, the contribution of renewable energy generation also increased from 257 MU in 2005–06 to 1,722 MU by 2015–16.This section will explore recent power procurement processes to highlight issues with planning.

Figure 3.14: Growth in contracted capacity in Haryana

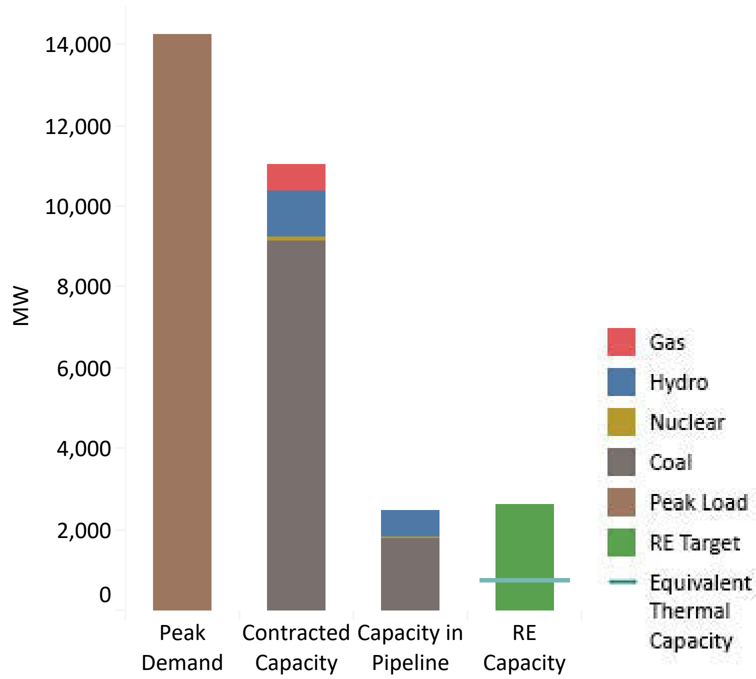


Source: PEG analysis based on regulatory submissions and orders

After the notification of the competitive bidding guidelines, the HPGCL reported that the 17th EPS projected a peak demand of 6,839 MW by 2011–12 for Haryana DISCOMs. However, Haryana DISCOMs projected demand of 11,555 MW by 2011–12 by assuming a growth rate of 15% per annum which is based on past DISCOM demand growth rates. Using this as a justification, Haryana DISCOMs sought to add 5,000 MW during the 11th Plan Period. This included the addition of 600 MW from Deen Bandhu Chhotu Ram Thermal Power Station (DCRTPS) 1,200 MW from the Ramgarh Gas Thermal Power Station (RGTPS) and 750 MW from IGSTPS at Jhajjar. After assessment of demand up to 2012–13 based on the same methodology, the Haryana DISCOMs decided to procure 2,000 MW via competitive bidding - 1,424 MW from Adani (Mundra) and 300 MW from GMR (Kamalanga) via PTC (HPGCL, 2009).

Even in the face of surplus, several PPAs are in the process of being renewed to tackle seasonal shortages. In 2015, while approving 50 MW from the Baglihar Hydro Project, HERC directed the DISCOMs to take stock of the status of existing PPAs and assess the need for renewal of PPAs. The DISCOMs projected demand using actual numbers till 2015–16 and applied the growth rates as published in the 18th EPS to project demand till 2021–22. As per the assessment of available power, DISCOMs seem to have deficit only for 2 to 4 months in a year. Sensing that the deficit months will increase with growing demand, the DISCOMs decided to renew most PPAs including NHPC PPAs and NTPC Faridabad (HERC, 2016). However, the DISCOMs are also surrendering power from Pragati TPP and reviewing the need for upcoming NTPC capacity.

Figure 3.15: Capacity addition in the pipeline expected by 2022 in Haryana[41]



Source: PEG analysis based on station-wise, contract-wise information available from regulatory orders, petitions and CEA reports and State Government documents.

As shown in Figure 3.15, Haryana DISCOMs also have planned to add about 2,459 MW of capacity by 2022 including capacity proposed for surrender as pipeline capacity. 78% of this capacity will be procured from the state generating companies. Additionally Haryana is committed to adding 4,142 MW of solar, 25 MW of small hydro power and 209 MW of biomass power by 2022. Thus even with

[41] Figure depicts fuel wise capacity in the pipeline expected to come online by 2022 juxtaposed with the current fuel-wise installed capacity as well as the peak demand projected in the 18th EPS for 2022. It also depicts renewable capacity addition assuming only part (60%) of the renewable energy target for the state as per national target for 2022 is achieved. Renewable energy is variable by nature, with lower plant load factors than thermal capacity. To reflect this, the bar for RE capacity addition also shows equivalent thermal generation capacity, denoted by a horizontal line. This is calculated considering CUF of 19% for wind power and 18% for solar power, and a PLF of 80% and auxiliary consumption of 8.5% for equivalent thermal capacity.

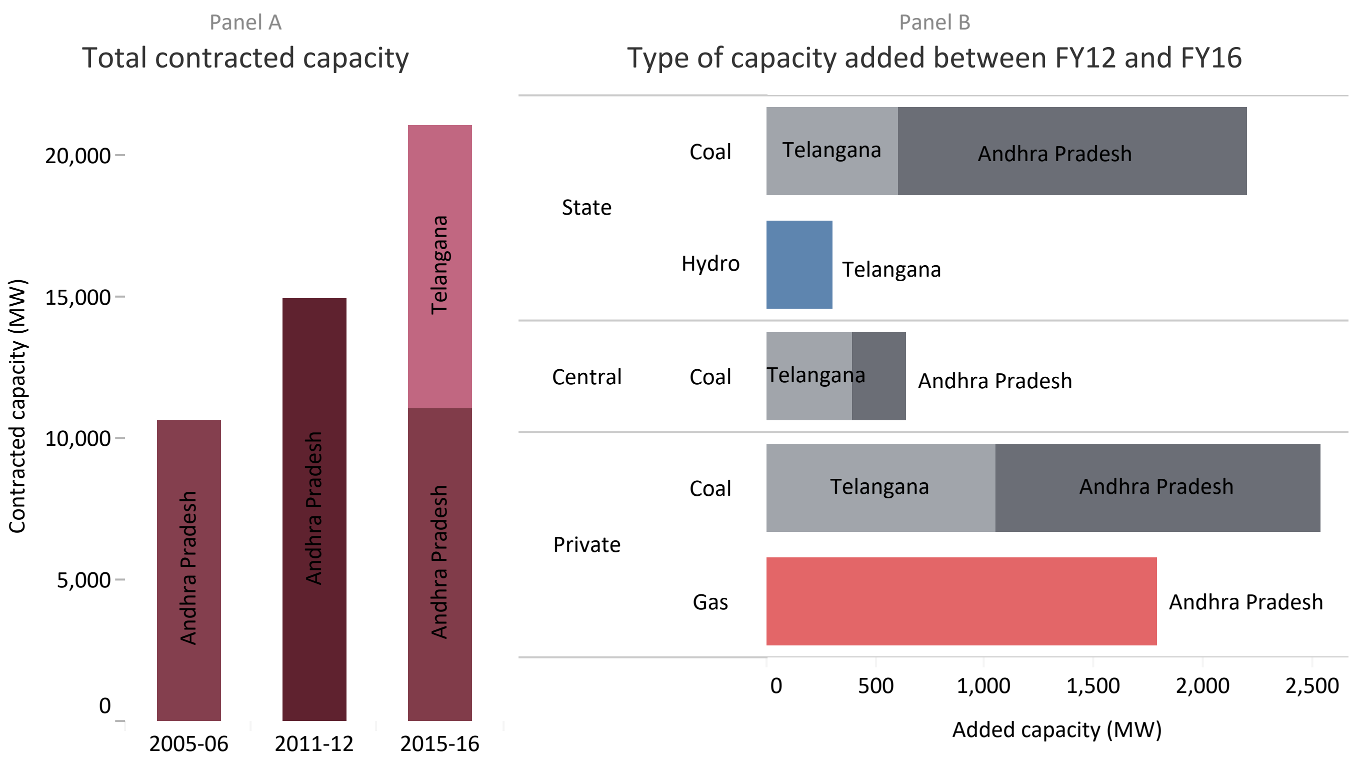
an optimistic demand outlook, Haryana DISCOMs may not need to contract power in the medium-term.

3.2.8 Andhra Pradesh and Telangana

The Andhra Pradesh and Telangana story is being told together to get a better sense of what took place in their united past, but the capacity addition in the pipeline will be examined separately. In order to ensure power procurement planning, the APERC notified guidelines for load forecast, resource plans and power procurement in 2006 (APERC, 2006). As per the guidelines, any power procurement planning exercise should be for a 10-year period and should forecast energy and peak requirements keeping in mind impact of open access, captive migration, seasonal and daily variations in demand, and impact of government policies. The supply estimations should include energy and peak capacity, availability of existing contracted capacity, upcoming capacity and new capacity requirements.

As is shown in Panel A of Figure 3.16, the non-renewable capacity procured by the two states in the past decade, has increased by about 40% between 2005–06 and 2011–12 and by 41% between 2011–12 and 2015–16. As a consequence of the bifurcation, the power contracted by the erstwhile Andhra Pradesh DISCOMs is being allocated such that the new Andhra Pradesh DISCOMs get 46.11% of the total capacity and Telangana DISCOMs get 53.89%. Panel B[42] shows that in the past five years, a significant amount of this capacity has been coal-based and that about 60% has been contracted from private plants and about 34% from state owned generating companies. Besides this, the 2015–16 renewable energy purchase in Andhra Pradesh is 2,363 MU, and in Telengana it is 474 MU.

Figure 3.16: Growth in contracted capacity in Andhra Pradesh and Telangana

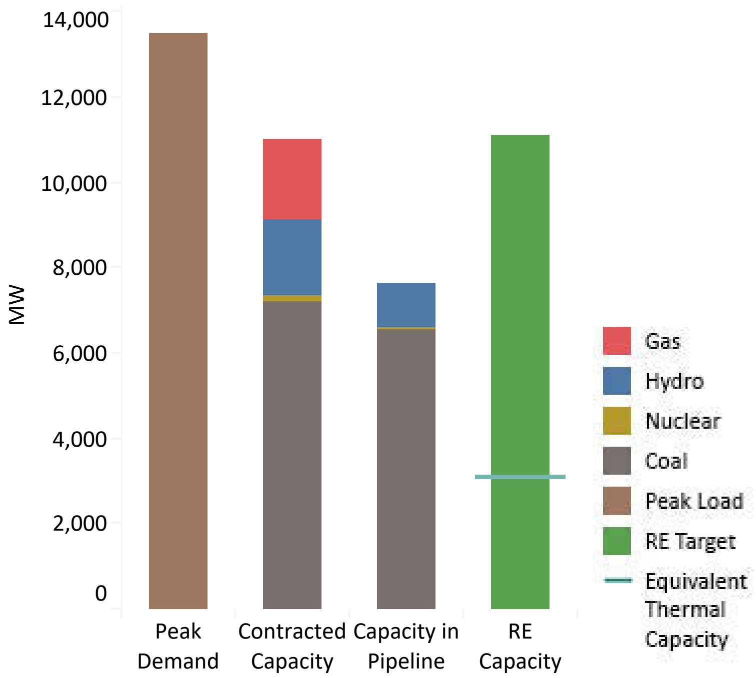


Source: PEG analysis based on regulatory submissions and orders

[42] Panel B reports the additional contracted capacity as on 31st March 2016. However significant capacity has been contracted by both states after this. Revised data would change the proportions.

Between 2016–17 and 2021–2022, Andhra Pradesh DISCOMs plan to add another 7,623 MW[43] of non-renewable capacity and Telangana DISCOMs expect an additional 11,240 MW. [44] In Telangana, more than 55% of the capacity in the pipeline is from TSPGCL and in Andhra Pradesh more than three quarters of the capacity in the pipeline is from APPGCL. Andhra Pradesh is committed to adding 9,834 MW of solar, 8,100 of wind power, and 543 MW of biomass-based renewable energy by 2022. Telangana plans to add 2,000 MW of wind power by that time.

Figure 3.17: Capacity addition in the pipeline expected by 2022 in Andhra Pradesh[45]



Source: PEG analysis based on station-wise, contract-wise information available from regulatory orders, petitions and CEA reports and State Government documents.

The peak demand estimates in Figure 3.17 are based on the estimates from Power for All plan, extrapolated to 2020-22.The capacity in the pipeline if online by 2022, will result in the installed capacity far exceeding the peak demand, even without the RE capacity addition. Even if the DISCOMs meet 60% of the renewable energy commitment, the power procurement will result in

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[43] This analysis considers all non-renewable capacity that has been added after 31st March 2016 as capacity in the pipeline. The estimates include 400 MW contracted from Simhapuri Energy Private Limited and 200 MW contracted from Meenakshi Energy Private Limited in the pipeline, even though they are supposed generate power for Andhra Pradesh DISCOMs from 2017.

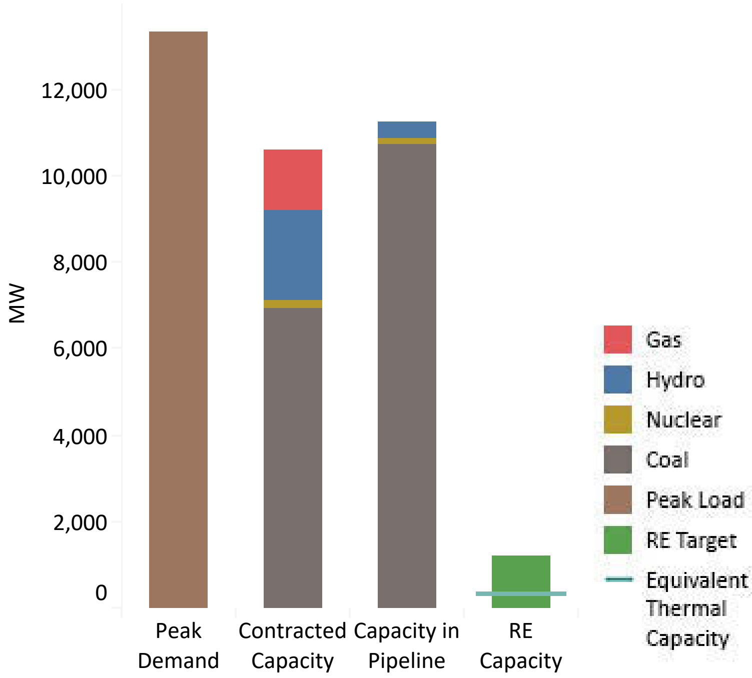
[44] This also includes 5,080 MW to be contracted from Manuguru TPP (Bhadradri) and Damarcherla TPP (Yadadri) which may not be available by 2022, and it includes 75 MW from the already commissioned NTPC Kudigi Unit 1 as the analysis considers capacity that has already been added after 31st March 2016 as capacity in the pipeline.

[45] Figure depicts fuel wise capacity in the pipeline expected to come online by 2022 juxtaposed with the current fuel-wise installed capacity as well as the peak demand projected based on the estimates in the Power for All Plan for 2018-19.This is because the 18th EPS has estimates only for unified Andhra Pradesh. It also depicts renewable capacity addition assuming only part (60%) of the renewable energy target for the state as per national target for 2022 is achieved. Renewable energy is variable by nature, with lower plant load factors than thermal capacity. To reflect this, the bar for RE capacity addition also shows equivalent thermal generation capacity, denoted by a horizontal line. This is calculated considering CUF of 19% for wind power and 18% for solar power, and a PLF of 80% and auxiliary consumption of 8.5% for equivalent thermal capacity.

more surplus or backing down of thermal capacity. Andhra Pradesh DISCOMs are also unable to sell much of this surplus capacity and are at the same time, renewing old PPAs.

In the case of Telangana DISCOMs, Figure 3.18 shows the peak demand estimates from the Power for All plan projected till 2022 based on the same growth rates. The non-renewable energy capacity in the pipeline is higher than the installed capacity today. With renewables the quantum of surplus will increase substantially. While it is true that the existing surplus in both states is much less as compared to other states, both Andhra Pradesh and Telangana need to re-evaluate projects in the pipeline in order to avoid future chronic surplus.

Figure 3.18: Capacity addition in the pipeline expected by 2022 in Telangana[46]



Source: PEG analysis based on station-wise, contract-wise information available from regulatory orders, petitions and CEA reports and State Government documents.

In a sense, Telangana and Andhra Pradesh are contracting capacity with as much a concerted drive as Maharashtra, Haryana and Rajasthan five to seven years ago. If all the capacity in pipeline materialises, both states will face severe impacts.

A detailed description of the various recently contracted capacity and the slew of proposals from Andhra Pradesh and Telangana for thermal capacity as well as renewable energy is beyond the scope

[46] Figure depicts fuel wise capacity in the pipeline expected to come online by 2022 juxtaposed with the current fuel-wise installed capacity as well as the peak demand projected based on the estimates in the Power for All Plan for 2018-19.This is because the 18th EPS has estimates only for unified Andhra Pradesh. It also depicts renewable capacity addition assuming only part (60%) of the renewable energy target for the state as per national target for 2022 is achieved. Renewable energy is variable by nature, with lower plant load factors than thermal capacity. To reflect this, the bar for RE capacity addition also shows equivalent thermal generation capacity, denoted by a horizontal line. This is calculated considering CUF of 19% for wind power and 18% for solar power, and a PLF of 80% and auxiliary consumption of 8.5% for equivalent thermal capacity.

of this report. What needs to be highlighted is that no comprehensive planning exercise as described in the guidelines has been undertaken for this purpose. For this, consider the case of recent processes for approval of capacity addition. One must also keep in mind that the states cannot depend on the 18th EPS estimates as the projections were published before the bifurcation.

The Commission allowed procurement of 600 MW in 2016 and 2,400 MW in 2017–18 on a long-term Design, Build, Finance, Own, Operate (DBFOO) basis subject to the demand-supply position. During this process, in a letter to the APERC, the DISCOMs make it clear that the estimations of power requirement for seven to twelve years are based on DISCOM calculations. They also said that any purchase over and above the estimate will happen with prior approval of the Commission (APERC, 2016a). In an earlier letter to the Commission, the DISCOMs, while justifying the purchase of 2,000 MW said that the implementation of Power For All (PFA) Programme to provide supply to all will lead to an increase in growth of demand, especially with the commitment to ensure 9 hours power supply to agriculture, promote industries and investment (APERC, 2014). If PFA numbers are anything to go by, this would mean an assumption of peak demand growth at 8% per annum (MoP, 2014). For Telangana, PFA on an average assumes peak demand to grow by 18% between 2014–15 and 2018–19.

Telangana is also planning to procure 1,000 MW for 8 years on a DBFOO basis (TSERC, 2016). The requirement is justified on the basis of providing uninterrupted power supply to all which also includes increasing hours of supply to agriculture from six hours to nine hours, and to rural households from 15 to 24 hours. It is also justified on the basis of upcoming infrastructure projects fostering demand and due to increased demand because of the government lift irrigation scheme. Given the demand growth rates and the fact that most contracted capacity by Telangana will not be commissioned before 2023, Telangana DISCOMs estimated a shortage of 2,865 MW to 3,928 MW in the interim, which is to be bridged by the power procurement for 8 years on a DBFOO basis. This was approved by the Commission on the basis that the recently commissioned but long delayed Hinduja TPP and Damodaram Sanjeevaiah TPP have been allocated to Andhra Pradesh instead of being shared by the states.

Among other reasons, the transmission corridor constraint and the fact that southern states do not have sustained surplus must contribute to the push in states like Telangana and Andhra Pradesh to build and contract more capacity.

3.3 Issues with power procurement planning

The capacity addition in the past decade has been quite substantial. Yet, this capacity addition was not preceded by a scientific forecasting exercise at the state-level to assess probable power requirements to meet future demand. This is despite all states having regulations or guidelines in place which detail the need for a long term power procurement plan which accounts for impact of energy efficiency, sales migration, retirement of plants etc., in the projections. Except in the case of Gujarat and Punjab, such regulations were in place when most of the capacity addition was taking place. The Madhya Pradesh regulations went further to state that in case of non-compliance, the commission can initiate suo-motu proceedings for the same. Still, no ERC (not even MPERC) has conducted regular, comprehensive power procurement planning exercises as intended in the regulations.

Most ERCs and DISCOMs rely on CEA EPS projections to forecast demand. States like Maharashtra have actively resisted using anything other than EPS estimates which is prone to overestimation. In the recent years, this is because the competitive bidding guidelines, call for an assessment based on EPS estimates to project power requirement. The competitive bidding guidelines also specify that regulatory approval for procurement planned is necessary if the requirement projected exceeds projected demand for the first three years after commencement of project. As most projected requirements were less than the overestimated EPS projections, regulatory approval for capacity addition through competitive bidding (from private projects) was not sought at all. Most states did not have transparent process before SERCs to assess demand and supply while contracting power from central and state-owned generating companies. There are states which relied on their own estimates to project demand. In the case of Rajasthan, the Commission's estimate was comparable to EPS estimates and in the case of Haryana it was far in excess of CEA estimates. However, the assumptions made to project demand were unrealistic, higher than EPS estimates, and not deliberated upon by the commission in public.

Often, the capacity in most states is more than the EPS estimates themselves either by a selective use of growth rates or by enhancing capacity procured or by citing several reasons for the deviation. The need to ensure better supply quality and uninterrupted surplus was used by almost all DISCOMs but no ERC or utility is linking capacity addition to service quality in order to hold states accountable for additional power purchase or better service quality. Another often cited reason is delays and slippages in upcoming capacity. If additional capacity is procured due to delays, it probably could prevent shortages in the short-run. However, in the long run when the delayed as well as the additional capacity come online, it will contribute to surplus power. Many projects are excessively delayed, contributing to high fixed costs and some of the contracted capacity has not even materialised. ERCs should play an active role in not just forecasting demand and supply but also weeding out projects which are delayed for long.

Many states took cognizance of the possibility of surplus while forecasting and relied on market sale of power to abate the issue. Another interesting observation is that not all states prefer to procure RTC power and have initiated contracts for peak/off-peak and even seasonal procurement which fell through due to lack of interested bidders. In many states, the issue of further capacity addition was being deliberated in the face of surplus.

Even though central and state sector generating companies contributed a considerable share, most of the capacity that was contracted in the recent past is from private generating companies. Conversely, as shown in Table 3.4, an overwhelmingly large proportion of the capacity in the pipeline is from central and state sector generating companies.

Table 3.4: Proportion of state and central sector capacity addition

<table>
<tr><th rowspan="2">DISCOMs in</th><th colspan="2">Proportion of CGS and state owned capacity to total capacity</th></tr>
<tr><th>Added between 2011-12 to 2015-16</th><th>To be added between 2015-16 and 2021-22</th></tr>
<tr><td>Maharashtra</td><td>40%</td><td>92%</td></tr>
<tr><td>Punjab</td><td>12%</td><td>70%</td></tr>
<tr><td>Haryana</td><td>22%</td><td>96%</td></tr>
<tr><td>Madhya Pradesh</td><td>55%</td><td>87%</td></tr>
<tr><td>Gujarat</td><td>29%</td><td>91%</td></tr>
<tr><td>Andhra Pradesh</td><td rowspan="2">42%</td><td>75%</td></tr>
<tr><td>Telangana</td><td>89%</td></tr>
</table>

Source: PEG analysis based on station-wise, contract-wise information available from regulatory orders, petitions and CEA reports and State Government documents.

Renewable energy generation has grown significantly across states and is currently substantial in many states especially western and southern states. The planning process of the past did not seem to consider capacity from renewables probably because DISCOMs viewed it as a means to meet statutory Renewable Purchase Obligation (RPO) compliance rather than treat it as capacity addition, and the scale was limited. With the massive capacity being added to meet the renewable energy commitment, renewable energy capacity addition should become part of the DISCOM planning discourse. This could also help prevent further backing down. Some of the thermal capacity addition in the pipeline can be justified as capacity required to balance generation, given the variable nature of renewables. As many states already have excess capacity, the need for building more capacity for this purpose has not been justified. Moreover, if this capacity is to be procured by DISCOMs and in all probability stay backed down on a sustained basis, then the cost of idle capacity will be borne by the DISCOM's consumers while the benefits of grid balancing will be enjoyed by open access and captive consumers as well. Thus one could argue that the cost of capacity procured for this purpose should be shared by all users of the grid and not just DISCOM consumers.

It is also interesting to note that the surplus states were easily able to procure and add capacity by finding bidders at competitive rates. However, states like Uttar Pradesh and Bihar which have an access imperative have not had much success with power procurement especially with private players. In an effort to procure 6,000 MW via competitive bidding, the Uttar Pradesh Electricity Regulatory Commission (UPERC) adopted tariffs ranging from ₹ 4.88/kWh to ₹ 5.73/kWh for 2,174 MW (UPERC, 2014). This could be due to poor credit worthiness, but this also means that these states are signing capacity at unfavourable rates. In such a case, reallocation of PPAs from surplus to deficit states would benefit both parties.

Even without accounting for the yet unallocated share of the 2,800 MW of nuclear power and 15,330 MW of hydro power, which is likely to be commissioned by 2022, surplus capacity in the pipeline is quite significant in most states. Therefore surplus power is going to be at least a medium-term issue.

4. How are DISCOMs and SERCs trying to manage surplus?

As backing down is increasingly becoming detrimental to the financial health of DISCOMs, SERCs as well as DISCOMs are trying various strategies to manage surplus. Some of these measures include sale of surplus, imposition of additional charges, reliance on banking arrangements, and encouraging off peak consumption. As several states have had diverse experiences with sale of surplus, this strategy is documented in greater detail.

4.1 Sale of surplus at a pre-determined price

The most logical alternative to backing down power is to find buyers for the surplus power. However, given high costs of surplus capacity, the revenue required to compensate the DISCOM from such sale can be substantial. DISCOMs have largely relied on the short-term power market to sell surplus power. Yet, the average price of electricity transacted through traders declined from ₹ 7.29/kWh in 2008-09 to ₹ 4.11/kWh in 2015-16. In the same time period, power exchange prices fell from and ₹ 7.49/kWh to ₹ 2.72/kWh (CERC, 2016). In 2015–16, the average off-peak night rate, when the likelihood of surplus is greater, was lower than this at ₹ 2.35/kWh (IEX, 2017). DISCOMs used to rely on the Unscheduled Interchange (UI) mechanism, often treating it as a market instrument for power transactions. [47] The price of power, transacted through the erstwhile UI mechanism or the current Deviation and Settlement Mechanism (DSM) plummeted from ₹ 4.62/ kWh in 2009–10 to ₹ 1.93/kWh in 2015–16. The recent prices, especially for DSM transactions may not be sufficient to compensate DISCOMs the cost of contracted capacity which is backed down, which calls for concerted efforts by DISCOMs to ensure sale of power.

DISCOMs are not the only parties which can sell surplus power. As per the 2016 amendment to the National Tariff Policy, 2005, if power contracted by any generator is not requisitioned by the procuring DISCOM, the generator can sell the power in the market. Any gains from such sale of power should be shared equally with the procuring DISCOM. Following this, in June 2016 the NTPC decided to sell un-requisitioned power from its generating stations at Vidhyanchal, Unchhahar, Rihand and Dadri on the power exchange (Singh, 2016). Due to low prices in the Indian Energy Exchange (IEX), the NTPC was only able to sell about 9% of the 30.5 MU it offered over nine days (Sengupta, 2016). Some private generators such as Jaypee Group's Bina TPP backed down by Madhya Pradesh DISCOMs and Adani Power's plant contracted by Rajasthan DISCOMs are also exploring options to sell un-requisitioned power.

Regulatory commissions have tried many ways to manage surplus power. Notable among them is the commission estimating surplus based on projected availability and approving a pre-determined price for sale of short-term power. The revenue from sale of estimated surplus at the pre-determined price is used to reduce power procurement cost estimates and thus reduce the revenue gaps[48] projected for the year. This section will discuss the impact of this method as well as several other means adopted by DISCOMs and ERCs to manage surplus in several states. It will focus on states where the surplus quantum is substantial (such as Punjab, Rajasthan, Maharashtra, Gujarat)

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[47] The Unscheduled Interchange mechanism which is now the Deviation and Settlement Mechanism is an instrument to ensure grid discipline via the levy of incentives and penalties for under-drawal and over-drawal of power. Often, it was treated as a real-time market to meet immediate requirements. The DSM mechanism has tighter bands in order to minimize such transactions and ensure grid security.

[48] Revenue gap is the gap between the total expenditure incurred by DISCOMs and the revenue recovered from retail consumers based on existing tariffs and the non-tariff income. The revenue gap is reduced or met by increasing tariffs; otherwise the unmet revenue gap would contribute to losses.

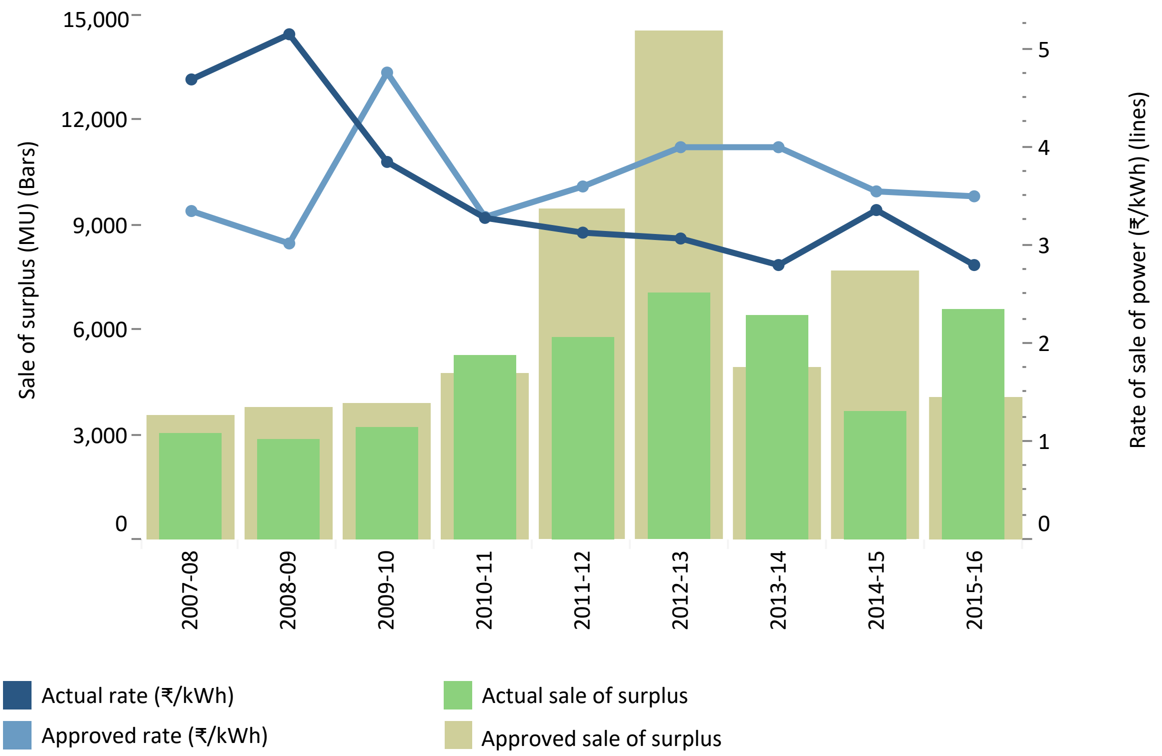
or where such efforts towards management of surplus have had significant impact on DISCOM's financial position, as in the case of Delhi.

4.1.1 Delhi

Delhi has been power surplus for almost a decade now. Nevertheless, the DISCOMs were not recovering the cost of backing down from its consumers. Instead, the DISCOMs were expected to sell surplus power in order to compensate for the power purchase expenses incurred. Based on projected availability and potential sales, the Delhi ERC has been estimating surplus generation in every tariff determination process, which is to be sold at an assumed rate.

As is clear from Figure 4.1, even though the surplus sold was less than anticipated by the commission, high rates for short-term power in 2007–08 and 2008–09 resulted in the DISCOMs earning an excess of ₹ 237 crore and ₹ 325 crore respectively from the approved revenues. In 2009–10, the DERC assumed a high rate of sale of power surplus, given the previous year's rates. The DERC was also optimistic about energy availability from new stations and projected significant quantum for sale. But, the energy availability was lower than projected and the demand higher due to 'a very harsh summer' (DERC, 2011). DISCOMs therefore resorted to short-term power procurement at high rates which contributed to substantially to revenue gaps and consequently, to mounting losses.

Figure 4.1: Projected and actual sale of surplus power in Delhi



Source: PEG analysis of various tariff orders and petitions

As seen in Figure 4.1, the DERC continued to project significant surplus for sale at high rates in 2011–12, 2012–13 and 2014–15, and the revenue realised from sale of surplus in these years were ₹ 1,596 crore, ₹ 3,656 crore and ₹ 1,485, crore in that order. This revenue was far lesser than the approved revenue as shown in Figure 4.1. Thus, DISCOMs were unable to compensate for costs and incurred losses. In 2012, DISCOMs approached APTEL with respect to the high rate of sale of surplus approved by the Commission (APTEL, 2015b). In 2015, the APTEL advised the Commission to consider short-term market trends in peak and off-peak periods during the year, while projecting price. It also approved the recovery of losses incurred due to high rates along with appropriate carrying cost from consumers (APTEL, 2015a).[49] The DERC allowed for this loss recovery via true up but disallowed costs for power "sold" via the UI/DSM mechanism, which accounted for 20% of the of total surplus power sold between April 2013 and September 2013 for one of the DISCOMs (DERC, 2015). It also directed the DISCOMs to explore longer term options such as banking and competitive bidding. Mounting losses and uncertainty in revenues is evidence that a different approach is required to manage surplus, or perhaps better estimation of availability, power requirement and surplus as well as rate of sale for surplus.

4.1.2 Punjab

In 2012–13, the Punjab SERC estimated surplus of 419 MU, based on projected availability to be sold at ₹ 3.29/kWh. The revenue projected from this sale resulted in a reduction of the estimated revenue gap by 7%. In 2013–14 the projected surplus grew to 5,734 MU. However, there was no adjustment on costs due to revenue from sale of surplus. In 2014–15 and 2015–16, the PSERC projected 3,118 MU as surplus for sale at ₹ 2.63/kWh and 1,737 MU as surplus for sale at ₹ 1.86 / kWh respectively. The rate for sale was based on the average variable cost of backed down plants. The projected revenue from sale at these rates enabled the Commission to reduce the revenue gap 58% and 88% in 2014–15 and 2015–16 respectively. The Punjab DISCOM, PSPCL, has not reported any sale of power from 2012–13 to 2014–15 in its true up filings. Perhaps realising the issues with this approach, in 2016–17 the Commission projected significant surplus but did not assume any revenue from sale of power.

4.1.3 Haryana

Over the years, the Haryana ERC also assumed the sale of significant surplus, based on projected availability at high rates to offset the power purchase cost and consequently reduce the revenue gap estimated for the year. This is clear from Table 4.1.

Table 4.1: Approved sale of surplus power and reduction in tariff increase in Haryana

Year	Projected surplus (MU)	Approved rate of sale (₹ /kWh)	Projected revenue from sale of surplus (₹ Cr)	% revenue gap offset by revenue from sale of surplus
2012-13	11,976	3.44	4,120	50%
2013-14	11,483	3.50	4,019	47%
2014-15	5,452	3.82	2,083	35%
2015-16	7,574	3.91	2,959	58%

Source: PEG analysis based on various HERC tariff orders

The Commission did not increase tariffs in 2016-17 as the DISCOMs were revenue surplus by ₹ 954 crore. The Commission also approved sale of 7,895 MU of surplus at ₹ 3.08/kWh. Without this projected revenue from sale of surplus, the DISCOMs would be facing a projected revenue gap of ₹ 1,477 crore. Meeting this revenue gap via tariff increase would have resulted in an 8% increase in tariffs. For the year 2013–14, the DISCOMs reported ₹ 1,722 crore from sale of power and in 2015–

[49] This is because the Commission was relying on the forward curve of spot price for December 2012 to June 2013 as reported by CERC's Market Monitoring Committee to approve price at around ₹ 4/kWh in 2012-13.

16 ₹ 1,929 crore, for this purpose. This revenue is much less than what was projected by the HERC (reported in Table 4.1). Evidently, DISCOMs incurred a loss from trading surplus power which they sought to recover from consumers during true ups. The Commission disallowed this recovery and noted that,

‘*The Commission notes with concern that the Discoms have already tied up for power which is in excess of its requirements for at least 5 to 7 years without having a system of power procurement planning and load forecasting and for optimization of power procurement cost. The Commission is of the considered view that the relief sought by the Discoms for recovering its trading losses from the Consumers is not admirable under any statute/regulation; hence the same is not admitted*.’ (HERC, 2014a)

This view was endorsed by APTEL in its Judgement in Appeal No. 269 of 2014 (APTEL, 2016).The exact nature and quantum of loss due to trading of surplus, as well as its cumulative impact, is still not clear. The ERC also actively encourages the DISCOMs to manage surplus by suggesting measures such as sale to power deficit states or DISCOMs, surrender of power, supply of additional power to consumers at concessional rates, etc. to reduce costs due to surplus.

4.1.4 Rajasthan

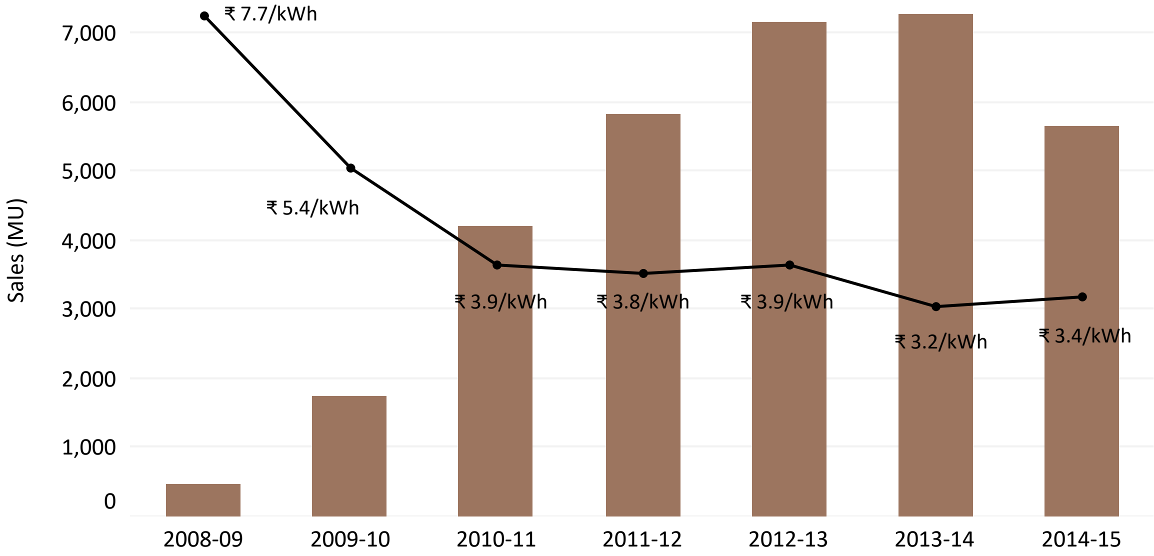
Rajasthan DISCOMs, started reporting surplus power only in the recent years. In 2013–14 DISCOMs had sold about 709 MU of surplus power via exchanges. In 2014–15 the DISCOMs proposed the sale of 4,194 MU of surplus at ₹ 2.11/kWh. The Commission approved the sale of 2,207 MU at ₹ 4/kWh (RERC, 2016c). The revenue assumed from such sale reduced the estimated revenue gap for the year by 15%. During truing up for the year, the DISCOMs submitted that they could only sell about 459 MW at ₹ 2.56 /kWh.

In 2015–16, the RERC projected high availability and assumed sale of 7,010 MU at ₹ 4/kWh which helped the commission reduce estimated revenue gap for that year by 45% (RERC, 2015b). This projection was made in spite of DISCOMs projecting only 3,983 MU of surplus to be sold at ₹ 2.2/kWh. During true-ups it became clear that only 575 MU were sold at ₹ 3.02/kWh (RERC, 2016b).

4.1.5 Gujarat

One of the earliest states to add substantial capacity, Gujarat was also among the first to sell surplus power in the short-term market. Unlike other states, the ERC did not approve a rate for sale of power or estimate a quantum for sale. Gujarat Urja Vikas Limited (GUVNL), the holding company for the state DISCOMs, as well as the entity which is signatory to all PPAs, sells long-term contracted power to the DISCOMs at the contract rate. In case of surplus, GUVNL sells it in the short-term market. The revenue earned from such transaction is adjusted in the revenue requirement of the DISCOM during true-ups. Figure 4.2 indicates that GUVNL has managed to sell significant capacity over the years. The rate of sale of power is higher than UI or DSM rates. Nevertheless, it is not clear if the revenue earned was able to compensate for the procurement cost of the surplus power sold.

Figure 4.2: Rate and sale of surplus power in Gujarat



Source: GUVNL annual reports for various years

4.1.6 Maharashtra

Under the Multi Year Tariff process, DISCOMs were to undertake a medium-term planning exercise and provide a business plan for the Commission's approval. Under this process, the Maharashtra State Electricity Distribution Company (MSEDCL) projected a surplus of 600 MU in 2013–14, 17,400 MU in 2014–15 and 23,900 MU in 2015–16 (MERC, 2015c). For reference, MSEDCL's total power purchase in 2014-15 was about 1,16,736 MU (MERC, 2016). Consequently, the commission approved the sale of 15,798 MU for 2014–15 at ₹ 3.92/kWh and 23,066 MU for 2015–16 at ₹ 4.10/kWh. As this was a business plan, it did not impact tariffs, but such optimistic projections impeded planning efforts. MSEDCL managed to sell 484 units at ₹ 2.02/kWh in 2013–14 (MERC, 2015a).

In 2014–15, MSEDCL assumed an optimistic sale of 6,500 MU of surplus at ₹ 3.59/kWh. Such sale was to offset 40% of the revenue gap projected by MSEDCL (MERC, 2015a). The Commission approved a sale of only 651 MU at ₹ 3.92/kWh that year. MSEDCL managed to sell 706 MU in 2014–15 at ₹ 2.67 /kWh (MERC, 2016).

For 2015–16, MSEDCL projected sale of 13,200 MU at ₹ 3.47/kWh, but the Maharashtra ERC did not approve sale of surplus that year .MSEDCL sold 877 MU at ₹ 2.15/kWh in 2015–16. (MERC, 2016). Thus, in Maharashtra's case, MSEDCL has been optimistic in projecting availability and therefore surplus whereas the commission has been less optimistic. Except in the business plan, MERC has approved a more reasonable magnitude of surplus for sale which has minimised trading loss. Yet, consumers still pay significant cost due to the backed down capacity.

4.1.7 Madhya Pradesh

From 2010–11 to 2013–14, the Madhya Pradesh ERC has been projecting a net power deficit for the state to be bridged by short-term power purchase. Still, in 2010–11, 2011–12 and 2012–13, DISCOMs were able to sell 419 MU, 881 MU and 1,398 MU of surplus power respectively (MPERC, 2016d) (MPERC, 2014b) (MPERC, 2014c). In 2014–15, the ERC decided to project a substantial 24,776 MU as surplus for sale at ₹ 3.15/kWh (MPERC, 2014a). To put it in perspective, MPERC approved a total power purchase of 81,527 MU in the same year. It is interesting to note that the

Commission did not approve any tariff increase that year, but without assuming such sale of surplus, the SERC would have needed to increase tariffs by 35% to cover costs incurred.

Continuing the previous year's practice, in 2015-16, the ERC projected 19,592 MU for at ₹ 3.16/kWh which would offset 72% of the revenue gap approved that year. As true-ups have not been conducted, there is no information about whether the DISCOMs had such high availability of power or if they were able to sell power at these rates. In the likely event that the sale was not possible, DISCOMs will report significant costs for recovery when the truing-up exercise for these years takes place. Such costs may be passed onto consumers. In 2016–17 the Commission approved the sale of only 8,300 MU of the 23,122 MU projected as surplus. The 8,300 MU to be sold at ₹ 2.5/ kWh were estimated based on availability from plants with a variable cost less than the average price discovered in power exchanges (MPERC, 2016a).

4.1.8 Andhra Pradesh and Telangana

In 2015–16, the Andhra Pradesh DISCOMs projected a surplus of 6,438 MU which they proposed to sell in short-term markets. The Commission projected a surplus of 1,410 MU for sale (APERC, 2015). The revenue earned was to be adjusted subsequently in true ups.

For 2016–17, the DISCOMs projected surplus of 7,142 MU. But, the ERC approved a surplus of 10,473 MU for the year to be sold at a pre-determined rate of ₹ 4.29/kWh. This reduced the projected revenue gap by 46% (APERC, 2016b).

The Telangana ERC projected 5,310 MU of surplus power in its first tariff order for the DISCOMs in 2015–16, for which no rate of sale was assumed (TSERC, 2015). For 2016–17, the Commission projected 4,337 MU of surplus. Though, thermal capacity with variable costs higher than ₹ 4.09/kWh (the rate for sale of surplus approved by the commission) is to be backed down. The sale of the remaining surplus would generate an additional ₹ 220 crore over and above the variable cost incurred for the surplus power. One assumes the fixed costs for the surplus power is being paid by the consumers (TSERC, 2016). As true ups have not been conducted for these years in either state, it is difficult to ascertain actual impact due to sale of surplus.

The effectiveness of using sale of surplus to offset revenue requirements rests on the ability of the DISCOM/SERC to project availability from stations with more scientific rigour and certainty. In many states such as Delhi, Punjab, Haryana, Rajasthan, Madhya Pradesh, Andhra Pradesh and Telangana, we see instances where the Commissions were projecting high availability which was possibly not achieved by the DISCOMs. In many of these states, the Commission projected higher surplus than estimated by the DISCOMs themselves. One can't help but wonder if projecting high availability and high rates for sale in order to project significant revenue from sale of surplus was used as a tool to camouflage revenue requirements and reduce the actual tariff increase that SERCs have to approve on an annual basis. The difference in revenue earned and revenue approved from trade of surplus is often passed onto consumers later during true ups. This approach also has negative implications for the success of Ujwal Discom Assurance Yojana (UDAY) as it postpones the recovery of costs and could increase future losses even though it may temporarily help in claiming adherence to UDAY requirements regarding bridging tariff gap. The Gujarat ERC, which does not project surplus but adjusts actual revenue earned from sale of power during true-ups is an exception to this trend. The Maharashtra ERC, which has been tempering the optimistic projections of the DISCOMs significantly is also an exception. In the recent years, the Punjab ERC and the Maharashtra ERC have adopted the practice followed in Gujarat.

Commissions have also been assuming a high rate for sale of power in order to compensate costs incurred, which are much higher than prevailing short-term market rates. Nonetheless, it is also true that many DISCOMs depend on UI transactions and the vagaries of day-ahead markets to transact such power instead of tying up weekly or monthly contracts for sale at more favourable rates. Practices such as disallowing the recovery of revenue loss from trading via UI/DSM transactions from consumers, or disallowing recovery from consumers of loss due to sale of power entirely, as followed in Delhi and Haryana respectively, are commendable. It is yet to be seen if such methods will nudge DISCOMs to adopt better practices to ensure sale of power. Selling surplus power is in the interest of the DISCOM as it can mitigate costs incurred due to backing down. If Commissions like HERC disallow the recovery of costs which could not be recovered from sale of surplus, it may not have tariff impacts but it will affect the financial position of DISCOMs. As HERC rightly points out, this loss is to be borne by DISCOMs whose power procurement practices are responsible for the current predicament. Therefore, if revenue from sale of power in the short-term market is not a enough to compensate the DISCOMs for costs incurred, other ways and means to mitigate the impact of surplus power need to be explored.

4.2 Banking arrangements

As discussed earlier, DISCOMs in Punjab, Haryana, Andhra Pradesh, Telangana and Rajasthan have to tackle power shortages while being power surplus. This is due to intermittent changes in demand. One way to manage this is via short-term power purchase, which is discussed in Section 2.1. The other is to have banking arrangements such that power can be exported to other DISCOMs in times of surplus and imported during deficit periods. The Haryana DISCOMs banked 2,436 MU in 2013–14 and this increased to 3,655 MU by 2015–16. Punjab has banking arrangements with other state DISCOMS which have significant hydro-power in the northern grid, namely Himachal Pradesh, Uttarakhand, Jammu and Kashmir. In 2013–14, these states purchased a net volume of 93 MU and by 2015–16 the PSPCL was importing 1,562 MU of power from them. The PSPCL plans to bank a net volume of 1,903 MU in 2016–17. In 2013–14, Rajasthan banked 1,881 MU. Rajasthan also has banking arrangements for power in the recent years but the exact quantum is unknown (RERC, 2016a). Unfortunately, it seems that only the surplus states in the northern grid are using this arrangement to meet requirements.

4.3 Additional surcharge

As per the open access regulations in many states, ERCs can levy an additional surcharge on open access consumers to compensate the DISCOMs for backing down due to fall in demand, which is attributable to sales migration via open access. Many ERCs have approved the levy of additional surcharge on open access consumers in the face of backing down of capacity. As discussed in Section 3.1, except in the case of Rajasthan, open access is not a major contributor today to backing down of capacity. Nevertheless, it is also true that the contribution of open access to backing down is increasing over time. As of February 2017, most states with significant backing down have levied an additional surcharge on open access transactions and the applicable charges are as shown in Table 4.2.

Table 4.2: Additional Surcharge levied across states applicable in 2016-17

State	Additional surcharge (₹/ kWh)
Maharashtra	1.11
Gujarat	0.44
Rajasthan	0.8
Punjab	1.13
Haryana	0.87

Source: Various regulatory orders

Madhya Pradesh DISCOMs have also petitioned the ERC for the levy of additional charges which it estimates at ₹ 1.02/kWh (MPERC, 2016c). Given the fact that open access accounts for 10% to 25% of the backing down in the states listed above, such a surcharge will not adequately compensate the DISCOMs for fixed costs incurred. The exception to this is Rajasthan where open access is responsible for over half the generation loss due to backing down.

As the surcharge is significant, it might be more effective in curtailing open access than in compensating DISCOMs. If renewable energy open access gets adequate concessions or if sales migration due to captive consumption increases, measures such as levy of an additional surcharge would not be sufficient to allay the predicament of DISCOMs with idle contracted capacity.

4.4 Surrender of power

Power from central generating stations is allocated to the states based on the Central Government guidelines (PIB, 2013). However, some DISCOMs, notably the Delhi DISCOMs, have requested for surrender of surplus capacity such that the power can be allocated to other states which require it. From 2010 to 2013, high cost power surrendered by Delhi DISCOMs was allocated to Kerala, Andhra Pradesh and Uttar Pradesh. On 6th May 2016, the Ministry of Power published a list of letters from the government of various states, asking to surrender of NTPC power to enable reallocation (MoP, 2016). Table 4.3 below summarises the capacities for surrender by states studied in this report.

Table 4.3: Request for surrender of allocation (MW)

Station	Delhi	Punjab	Haryana	Rajasthan	Madhya Pradesh
NTPC Badarpur	285				
NTPC Anta	72	65	102		
NTPC Auriya	91	101			
NTPC Dadri	44	147			
APCPL Jhajjar	693	23	693	10	
Dadri Stage II	735				
NTPC Mouda Stage 1					156

Source: (MoP, 2016)

It is interesting to note that except in the case of Delhi, the quantum of power for surrender is small and many states reeling under surplus such as Gujarat and Maharashtra did not request for the surrender of any capacity. As per the PPAs with central generating companies such as NTPC, the company has the right to discontinue and reallocate power supply in case the contracting DISCOMs do not make timely payments. Until such reallocation is made, the state is liable to pay capacity charges. In the case of Delhi, the NTPC also has resorted to reallocation due to non-payment (NTPC, 2016). Punjab and Haryana are also making efforts to surrender capacity including capacity from private generators. The PSERC commissioned a study to review PPAs which detail options for sale and surrender of power. As per the report, the commissioning of all units of the backed down Goindwal Sahib Power Plant and Talwandi Sabo Power Plant were delayed for over a year above the scheduled dates. Therefore, as per the PPA, PSPCL can move for termination of contracts (PSPCL, 2015, p. 274). It is yet to be seen if the PSPCL acts on this advice. The Haryana Power Procurement Cell has proposed the surrender of Pragati Gas Power Station to the Delhi Government and is currently awaiting its response (UHBVN, 2016). Yet, such efforts are few and far between. As procurement of power is based on long-term contracts, surrender of power, especially of private capacity can involve legal complications. Currently, even central and state sector generating stations are not keen to facilitate surrender of power. The states need to explore the surrender and possible re-allocation of surplus power, as well as strategies to enable the same.

A related strategy adopted by DISCOMs in Gujarat and MSEDCL in Maharashtra is the early decommissioning of state-owned generation plants which are old and frequently backed down. GSECL's Gandhinagar TPS will be decommissioned in 2016 and Ukai TPS Unit 1 and Unit 2 as well as Stage I of Sikka TPS will be decommissioned in 2018. In Maharashtra, MSPGCL has proposed the decommissioning of Chandrapur TPS Unit 1 and Unit 2, Bhusawal Unit 2, Parli Unit 3 and Koradi Unit 5 by 2016–17.

4.5 Reviewing/deferring capacity addition

A crucial long-term measure to manage surplus is to stop or review capacity addition. The current predicament of DISCOMs necessitates a critical evaluation of the need for capacity in the pipeline. This calls not just for re-evaluation of planned capacity addition but also an examination into the need of capacity currently in the pipeline. In response to the growing surplus, MERC decided to direct DISCOMs to

'*…review its PPAs and explore options to optimise the impact of the fixed cost of the contracted capacity, <u>including deferment in cases where no significant work execution has taken place so far [emphasis added]</u>.*' (MERC, 2016)

In a suo-motu petition to assess the status of Haryana DISCOM PPAs, the Haryana ERC explored the possibility of surrendering existing power, especially power without PPAs or where PPAs are expiring. ERCs in Punjab and Rajasthan have highlighted the need for planning, forecasting and managing existing PPAs, but none of the ERCs have taken this bold and much needed step. It is yet to be seen if the MERC will review the requirement of proposed and upcoming plants and if other states will follow suit.

4.6 Lessons and observations

In order to manage surplus and limit fixed cost payments for backed down capacity, most ERCs are projecting sale of surplus at a pre-determined rate. Insights from various states show that this approach is effective if and only if the projected generating availability is realistic, and if the DISCOMs explore other options to sell power besides the power exchanges and the DSM mechanism. Along with sale of surplus, many DISCOMs especially in the Northern Grid are exploring banking arrangements to mitigate off-peak surplus and meet peak demand. This is a good practice whose viability should be explored in other states.

Levy of additional surcharge can compensate for backing down due to open access but the current contribution of open access to backing down (except in the case of Rajasthan) is not substantial. Additional surcharge discourages open access. Yet, it does not address the issues of variability in demand due to short-term open access, which could be significant in the future.

Efforts to surrender contracted capacity and review capacity addition in the pipeline is the need of the hour to ensure that states are able to mitigate backing down and avoid paying for idle capacity in the future. However, efforts in this direction are few and far between, possibly due to legal and contractual hurdles. Reallocation of power would be an efficient way to use resources as it could reduce the need for new capacity to cater to the growing demand in deficit states, states with access issues and significant latent demand.

5. Commentary

5.1 Key insights from the states

Extensive capacity addition in the recent past, justified on the basis of overestimated demand has been the primary cause of backing down, not an unanticipated reduction in demand due to sales migration and economic slowdown. Moreover, continued capacity addition in the face of sales migration, falling prices and renewable energy capacity addition commitments, are only going to intensify the current issue. Surplus power will either need to be sold or be backed down, and thus, it is an issue which needs to be urgently addressed. This section provides a commentary on the insights and lessons from state experiences and identifies ideas to manage and avoid future surplus on large scale. Some of the key insights and lessons are:

1. **Over-estimation of demand, along with poor power procurement planning, is the major contributor to the surplus predicament**: Many DISCOMs have significant surplus power due to overestimation of demand, and the massive capacity addition in the recent past, without proper power procurement planning. Most DISCOMs have significant capacity addition planned in order to meet their future demand. However, they are faced with lower than anticipated demand because the demand projected on which the capacity addition was based was hugely overestimated. Even though DISCOMs are required by SERC regulations to conduct long-term forecasting exercises on a periodic basis to aid power procurement planning, most rely on CEA EPS estimates for forecasting demand. This position is justified and in some cases, defended based on the recommendation in the competitive bidding guidelines to do so. CEA demand estimates are intended for the whole state, not just DISCOMs, and thus do not account for sales migration due to open access. Moreover, the five-yearly estimates are not regularly revised, which disconnects them from the state realities at the time of planning for power purchase. These estimates also have several methodological flaws and have been known for consistently overestimating demand over the years. In addition, DISCOMs also often diverge from the EPS estimations to offer higher demand projections.

   With respect to capacity addition, if capacity comes online as planned, on time, and in the face of lower than anticipated demand, it could contribute to surplus. In case capacity planned is cancelled, it could contribute to shortages, but the probability of that event is low, especially if demand is lower than anticipated. If the capacity is delayed, in the intervening period, it could lead to shortages, which would spur a call for increased capacity addition. In the medium or long-term, when the delayed and new capacity comes online, at a time when the demand-supply circumstances have changed, it could contribute to surplus. Both the overestimation of demand and lack of realistic projections for anticipated supply are indicative of planning failure.

2. **The contribution of sales migration to the current surplus is not substantial**: Sales migration due to open access is responsible for only a part (10% to 25%) of the total backing down in most states. The reduction in demand due to open access was not unforeseen, given the annual decrease in DISCOM sales to open access eligible consumers. But, changes in demand due to open access is difficult to plan for, as most open access is short-term. Even though the quantum is small now, sales migration due to open access and captive options is bound to grow, making

power procurement planning even more challenging. Another factor frequently mentioned as a driver of surplus is slow growth in demand. The gap between projected demand and actual demand is indeed significant. Yet, compared to historical trends, demand growth in the recent past has slowed down only marginally. This points to the fact that the primary reason for surplus is not slowdown but overestimation of demand in the first place. Unfortunately, such overestimation of demand has been a recurring phenomenon, though little attention has been given to improved demand forecasting.

3. **Surplus does not imply the elimination of shortages in the state:** Due to seasonal variation in demand, it is possible to have DISCOMs facing shortages and having surplus capacity in the same year. Such DISCOMs face significant fixed cost payments for backing down and have to procure additional power in the short term market, or engage in seasonal load shedding as well. Banking and sale of power allay these impacts, but need to be buttressed with more efforts to have medium term flexible contracts to address variability in demand. Unfortunately, despite realising the need for such contracts at the time of power procurement, lack of adequate efforts from the DISCOM and lack of interest from generators for seasonal, peak contracts has resulted in DISCOMs procuring long term RTC power to meet seasonal shortages. This has also contributed to surplus capacity.

4. **Sale of surplus power is used as an instrument to temporarily defer tariff increase required**: Many of the states with surplus power are also reeling under financial losses, high tariffs and any additional revenue from sale of surplus could be an advantage. However, when SERCs, in some cases at the utilities' behest, approve sale of surplus during tariff determination, the surplus power assumed for sale is high, based on optimistic assumptions of power availability. Since the rate of sale of power assumed is also high, the approved revenue from sale of surplus is substantial. The assumed revenue is used to reduce projected expenditure, decreasing the revenue requirement from tariff and therefore offsetting revenue gaps. In reality, the DISCOMs are unable to earn projected revenues and are stuck with losses, as they cannot realise the high surplus or sell power at assumed rates. The losses incurred are either to be recovered from tariffs via true ups or, if disallowed, are added to unfunded losses to be recovered via bailouts in the future. Such practices are detrimental to the finances of the utility, hinder the success of programs like UDAY, and reduce the legitimacy of regulatory decisions.

   If a realistic surplus is projected for sale at probable prices, ERCs can nudge DISCOMs to ensure sale of power. Such measures could also encourage utilities to look for options beyond day-ahead market trade or the DSM (Deviation and Settlement Mechanism) to manage power surplus. This is especially true if ERCs and DISCOMs were to rely on scientific demand-supply projections and, following this, were to disallow any losses from sale of power. Alternatively, ERCs can also adopt the practice in Gujarat where surplus is not projected but sold when possible, and the actual revenue adjusted during true-ups. Past experience with sale of power highlights that the rates which will recover cost of surplus cannot be realised from sale of surplus in short term markets. Thus, in order to make this strategy work, DISCOMs will also have to explore other avenues for sale of power including medium term contracts.

5. **Supply in the name of access, but where is access in the face of surplus?** : Another often cited reason to justify power procurement is to meet the goal of providing uninterrupted power

supply to all. Still, DISCOMs are not held accountable for ensuring quality power supply to all once this capacity comes online. Without regular monitoring, (including feeder-level AMR data being published on website) accountability and concurrent programmes to provide sustained, uninterrupted supply along with capacity addition, procuring power in the name of increased access perhaps amounts to mere tokenism, and a very costly one for consumers and the state's economy.

6. **Sale of surplus can offset new capacity addition in other states**: The variable cost of coal-based capacity which is backed down for over 50% of the time is in the range of ₹ 2.7/kWh to ₹ 3.3/kWh. This is much lower than the per unit cost of power being contracted by many DISCOMs who face shortages. Notwithstanding transmission constraints, this implies that shortages in certain states can be allayed by purchase of power from surplus states. Many states with an access imperative, in need of power, also have poor finances and low creditworthiness. This makes is difficult for them to procure power at favourable rates via competitive bidding, unlike the surplus states. In this context, reallocation of PPAs from surplus to deficit states, even for the medium term, would benefit both parties, with host state continuing to bear some credit risk in order to reduce fixed cost burden.

7. **Coal-based generating plants, especially state owned plants, accounts for most of the backed down capacity:** Coal-based plants account for more than 60% to 90% of the loss of generation due to backing down. Though gas-based plants are backed down extensively due to high fuel costs, they form a small proportion of the total backed down capacity. Except in the case of Punjab, capacity owned by state generating companies accounts for about 60% to 80% of generation lost due to backing down of coal-based plants. Across the country, with the advent of surplus, state owned generating plants were also among the first to be backed down, and this could be because of their high variable cost. However, with increasing surplus capacity, private and central sector is also getting affected. Most of the coal-based capacity which is backed down is not shut down, but is partially utilised, leading to low plant load factors. In most cases, the extent of backing down ranges from 10% to 60% of plant availability.

8. **Newly commissioned plants are also getting backed down**: Across states many newly commissioned plants are also being backed down due to their high variable costs. Much of this capacity was contracted in the years when the states were already facing surplus. Better planning could have avoided a situation where capacity was being commissioned only to lie idle. Projections for upcoming years in some states also indicate that the capacity currently in the pipeline is likely to be backed down from the year it comes online**.**

9. **Most of the capacity in the pipeline is from central and state owned generating companies**: In many states, the private sector had a major role to play in the capacity addition over the past decade. However, analysis of the capacity in the pipeline to be commissioned by 2022 shows that almost all of the capacity in the pipeline is owned by central sector utilities or by state generating companies. Therefore, a concerted plan for re-allocation of capacity is possible with commitment and cooperation from the central and state governments.

10. **With increased sales migration and capacity addition in the pipeline, surplus power is here to stay:** All surplus states continue to have significant capacity addition in the pipeline. Due to increase in open access, migration to captive options and the proliferation of renewable power, whose costs are declining rapidly, demand for utility power will not be as high as is projected by DISCOMs. The possibility of increased industrial and economic growth does not, in today's dynamic situation, necessarily imply an increase in demand for the utility, as consumers can migrate to other sources of supply. Therefore, even though thermal capacity addition is not as aggressive as in the past decade, states will continue to have surplus for many years to come. The quantum of surplus will be further exacerbated even if the renewable energy target of 175 GW by 2022 is met only in part (say 40% to 70%). Therefore, DISCOMs need to think of solutions to manage such surplus on a sustained, medium-term basis and think of ways to review capacity in the pipeline to avoid future surplus.

5.2 Suggestions for the way forward

Given the present status and future possibilities with surplus, a few suggestions to help manage existing surplus and avoid further surplus follow. Many of the suggestions require detailed deliberation and discussion, and this section only seeks to provide a potential set of ways to explore appropriate measures to manage surplus.

1. **New PPAs only after extensive review of demand and supply projections:** Since surplus is not a transient phenomenon, and considering its wide-spread ramifications as well as capacity in the pipeline, all ERC and DISCOMs should commit to signing new PPAs only after a robust and consultative process to establish the case for additional power procurement. Some aspects of such extensive review process are discussed in this section.

2. **Ensuring robust demand forecast and capacity addition planning exercises**: A comprehensive review of demand and supply by the DISCOM should consider the impact of many past and potential changes and should be based on disaggregated historical trends. Many of the existing regulations already specify the need for demand forecasts which account for sales migration, impact of energy efficiency and seasonal variation in demand. Such regulations also emphasize the need for regular review of capacity while planning power procurement. DISCOMs and ERCs should conduct regular exercises (say, every alternate year) for demand forecast and capacity addition where:
    a. There are separate medium, and long-term demand forecasts for base, intermediate and peak load; which also considers macroeconomic indicators, progress of government development programs, historic trends of sales, elasticity of sales to tariffs, and change in appliance usage;
    b. Impact on demand and supply due to sales migration, energy efficiency measures, integration of renewable energy, retirement of plants, repair and maintenance works are also considered;
    c. The commission takes a critical look at the capacity in the pipeline and reviews whether capacity can be surrendered or reallocated as appropriate. This could also ensure the timely and firm exit from projects which are incessantly delayed and unlikely to come up in the near future. Such a review should consider status of plants in the pipeline to assess impact of costs due to delay in commissioning and deferment due to not getting statutory clearances. Capacity which is significantly delayed is weeded out by surrendering capacity

or initiating the process for PPA termination based on an informed call. This will reduce uncertainty and the cost burden imposed on DISCOMs due to delays and reduce the possibility of backing down;

d. A mix of strategies for procurement, which can be a combination of short-term medium, and long-term contracts as well as banking arrangements are used to meet the power requirement.

The practices for demand estimation and review of capacity in the pipeline can be formalised by adding them in existing regulations or by introducing new regulations for power procurement planning. Moreover ERCs and DISCOMs should be committed to ensuring that these practices are followed.

3. **Regular review of capacity addition in a public process similar to tariff determination to be used as basis for capacity addition**: The process of such a review which consists of practices described above, should be regular, consultative and transparent. Power procurement accounts for about 70% of the DISCOM costs and concerns all consumers. Processes for estimation of demand and capacity requirement are ad-hoc, non-transparent and conducted only before major power procurement. It is imperative that ERCs conduct a public review of capacity addition in the pipeline and forecast demand every two years. Such a process would be akin to the tariff process conducted by SERCs on an annual basis. As in the tariff processes, SERCs should conduct suo-motu processes in case of delay in filings for this process by the DISCOM. Moreover, the petitions of DISCOMs for this should be publicly available, the consultation should be via public hearings and the orders for this process should be reasoned orders. This will ensure transparency, increased public engagement and greater accountability towards power procurement requirement practices. In order to operationalise this, ERCs should draft or amend appropriate regulations which include provisions for consultations through public hearings and regular transparent review of capacity addition.
4. **Need for regular, disaggregated, dynamic projections by CEA and independent projections by DISCOMs**: The report has explored how the dependence on CEA estimations has contributed to surplus growth. CEA EPS estimations can reflect the realities of the utility if:
   a. Revised estimates were released every 2 years to account for change in demand and change in base assumptions;
   b. The forecast reflected utility demand as it currently captures demand for the state and this includes demand from open access consumers. CEA needs to separately project demand from open access consumers as well as consumers using roof-top solar options. However, this would be hard for the central agency, but much easier for the utility to estimate.

   Therefore, it is imperative that utilities conduct their own demand estimation exercise independent of CEA estimates. To ensure that utilities conduct their own demand estimation exercises, it is suggested that the competitive bidding guidelines be amended accordingly. It is also suggested that the CEA should further highlight that the EPS estimates apply to the whole state and not the utility alone, and that this would be inappropriate to adopt the same for power procurement planning purposes.
5. **Include power procurement planning in DISCOM rating exercises**: Power procurement planning is intrinsically connected to DISCOMs' financial predicament and has a major bearing on the success of national level programmes such as Ujjwal Discom Assurance Yojana (UDAY) and Power for All. The Annual Integrated Ratings of State Power Distribution Utilities, published by

the Power Finance Corporation Limited, considers the competitiveness of power purchase as a criterion for performance evaluation of DISCOMs. Along with this, the ratings should also factor criteria to track robustness of power procurement planning practices. Therefore, adherence to SERC guidelines and regulations, and public review of power procurement planning should be part of the evaluation criteria for operational and financial performance of the utility in such rating exercises.

6. **Strengthen planning capacity**
    a. **Institutional support for utility planning wings:** This report tries to make a case for the importance of planning, especially in the context of the current flux in the power sector. Planning is critical to the survival of DISCOMs and should be prioritised. This could be done by increasing the strength and capacity of power procurement, demand forecasting and planning wings and by expanding the nature and scope of their work.

    b. **Use of advanced planning and dispatch tools in planning process**: Given the state of flux in the utility business, forecasting demand and supply and optimising scheduling can be difficult. It is suggested that utilities use advanced planning and dispatch tools in order to assist DISCOMs in decision making. Such tools would allow utilities to develop different scenarios to ascertain the impact of demand trends in varying temporal resolutions, to model changes in weather patterns, to understand impacts of grid integration of renewable energy and to ascertain impact of sale of surplus power. Such tools can help reduce the uncertainty which the DISCOMs are currently facing.

7. **Need for robust market instruments to ensure optimal utilisation of power**: As surplus power co-exists with shortages, there is a need to develop and increase the use of market based instruments to encourage trading on a monthly, seasonal, medium-term basis to enable sharing of generation. Power exchanges have instruments for week-long trades which can be explored by DISCOMs and open access consumers and the Discovery of Efficient Electricity Price (DEEP) platform does provide an opportunity for reallocation of power based on auctions. The scope of the platform should be widened to include sale to inter-state open access consumers as well. Moreover, market instruments for longer durations and with high flexibility should be introduced in the power exchange to cater to this need and can be provided by traders as well. In order to ensure sale of power or reallocation of power are viable strategies to deal with surplus power, it is important to ensure adequate transmision and subtransmission investments to ease bottlenecks and and ensure delivery of power.

8. **Use of surplus power to provide conditional low cost power procurement options to states with an access imperative**: Surplus capacity, though high cost, can provide states where electricity access is lower than the national average with an incentive to supply uninterrupted power to consumers in rural areas, especially newly electrified areas. Due to issues with creditworthiness, they are also not able to negotiate favourable rates while procuring new capacity. One approach to provide these states with low cost power, can be to reallocate the surplus capacity to these states, at concessional rates. Such concessions can be provided if:

    a. the host surplus state decides to forgo part of the fixed cost (say 50 paise per kWh) while selling power to recipient states;

b. the central government foregoes the revenue from the levy of the clean environment cess for the re-allocated capacity which will reduce the cost of generation and thus power procurement;
c. financial support is provided such that central government and the recipient state governments share the additional cost to supply at concessional rates.

The concessions should be revoked in case the power is not being supplied for a minimum of 16 hours in the identified feeders. For this purpose, the feeders should be monitored by the central government via AMR (Automatic Meter Reading) meters to ensure uninterrupted supply. Such arrangements could be put in place for the medium-term, say one to four years, until the host state is in a position to absorb surplus capacity without concessions.

9. **Reallocation of power**: Another variation of the above idea to use the surplus power could be the reallocation of PPAs via surrender and consolidation of surplus power, aimed at addressing inability of distribution companies to have effective pricing flexibility (i.e. selling power below PPA cost) to have sale of power in surplus market conditions. In order to do this, the Union Government can create a Special Purpose Vehicle (SPV) or can use PTC (Power Trading Corporation) which can consolidate and bundle existing surplus power to enable re-allocation. In order for the scheme to work:

   a. Utilities should identify power which can be surrendered on a sustained basis after taking into account power requirements for the coming three to five years;
   b. Such power, be it from a private generator, central or state generator should be surrendered to the SPV within a 3 month window;
   c. The tariff as per the PPA or the latest approved SERC tariff, will be applicable for the surrendered power;
   d. The SPV can pool all the surrendered power and determine a pooled power procurement price, revised periodically. Based on this and market conditions, SPV will decide the price for sale of power to interested parties. The SPV can sign month-long, seasonal, annual or medium-term contracts for this purpose. The power can be procured by open access and captive consumers, other DISCOMs and traders;
   e. Losses if any, arising out of SPVs inability to sell power will be shared by all participating DISCOMs on a pro-rata basis;
   f. As per the scheme, states which have surrendered power cannot procure any power for the coming three to five years. All additional power requirements should be fulfilled by purchasing power from the SPV;
   g. Along with other options, in states which seek to provide uninterrupted power supply to rural areas, (say, in states where the household electrification rate continues to be below the national average), the reallocation can take place at concessional rates. As in the previous suggestion, the concessional rate can be due to conditional grants from the union and state governments or waiver of clean environment cess for plants allocated for this purpose. The concessional rate would be conditional to uninterrupted supply of at least 16 hours per day on selected feeders which are monitored.

10. **Tariff and regulatory measures to discourage short-term open access and to promote sales by DISCOMs:** As sales migration due to open access rises, it could create serious issues for DISCOM operation and planning in the future and could also increase the quantum of surplus power. In order to discourage consumers from migrating, SERCs can provide lower tariffs for additional units of consumption by large scale employment generating enterprises. Another idea would be to provide large consumers with a significant rebate if their consumption this year exceeds that of the previous year. Utilities and ERCs need to consider more such innovative tariff measures to retain consumers. Short-term open access makes demand forecasting and power procurement planning difficult and thus it should be discouraged. This can be done by:

    a. Changing relevant SERC open access regulations such that no open access is permitted for duration of less than one year.
    b. Levying a higher additional surcharge on short-term open access consumers than which is levied on medium-term and long-term open access consumers.

For over two decades, the sector has been struggling to address the two crucial issues of excessive transmission and distribution losses (including commercial losses) and excessive cross-subsidy in tariffs. This has severely affected financial viability of the entire sector. Unless urgent attention is given to the management of surplus power and more importantly, preventing build-up of more surplus capacity, this would become an equally significant challenge to the financial viability of the sector. The issue of surplus capacity would be more difficult to address as it involves huge capital investments, lock-in of scarce resources and long-term legal contracts, often with private sector developers.

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List of Abbreviations

APPGCL	Andhra Pradesh Power Generation Corporation Limited	kWh	Kilo-watt hour
APTEL	Appellate Tribunal for Electricity	MERC	Maharashtra Electricity Regulatory Commission
BU	Billion Units	MoD	Merit Order Dispatch
CAGR	Compound Annual Growth Rate	MPPGCL	Madhya Pradesh Power Generating Company Limited
CCPP	Combined Cycle Power Plant	MSEDCL	Maharashtra State Electricity Distribution Company Limited
CEA	Central Electricity Authority	MSPGCL	Maharashtra State Power Generation Company Limited
CERC	Central Electricity Regulatory Commission	MU	Million Units
CUF	Capacity Utilisation Factor	MW	Mega Watt
DBFOO	Design, Build, Finance, Own, Operate	MYT	Multi Year Tariff
DERC	Delhi Electricity Regulatory Commission	NEP	National Electricity Plan
DISCOM	Distribution Company	NHPC	National Hydroelectric Power Corporation Limited
DSM	Deviation and Settlement Mechanism/ Demand Side Management	NTPC	National Thermal Power Corporation
EAC	Energy Assessment Committee	PFA	Power For All
EPS	Electric Power Survey	PLF	Plant Load Factor
ERC	Electricity Regulatory Commission	PPA	Power Purchase Agreement
GERC	Gujarat Electricity Regulatory Commission	PSERC	Punjab State Electricity Regulatory Commission
GSECL	Gujarat State Electricity Corporation Limited	PSPCL	Punjab State Power Corporation Limited
GUVNL	Gujarat Urja Vikas Nigam Limited	RERC	Rajasthan Electricity Regulatory Commission
GW	Giga Watt	RTC	Round The Clock
HEP	Hydroelectric Power	RVUNL	Rajasthan Rajya Vidyut Utpadan Nigam Limited
HERC	Haryana Electricity Regulatory Commission	SLDC	State Load Despatch Centre
HPGCL	Haryana Power Generation Corporation Limited	STU	State Transmission Utility
HT	High Tension	TPP	Thermal Power Plant
HVPN	Haryana Vidyut Prasaran Nigam Limited	TSPGCL	Telangana State Power Generation Corporation Limited
JPVL	Jaiprakash Power Ventures Limited	UI	Unscheduled Interchange
JVVNL	Jaipur Vidyut Vitaran Nigam Limited	UMPP	Ultra Mega Power Project

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http://www.prayaspune.org/peg/publications/item/332.html

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The Price of Plenty

Insights from 'surplus' power in Indian States

With significant capacity addition in the past decade, many states in India have transitioned from having chronic power shortages to having sustained power surplus. The growing volume of surplus capacity in various states is a matter of concern as it implies rising fixed-cost payments for the non-requisitioned or backed down power. This scenario may continue for a few more years with less than anticipated growth in demand, capacity in the pipeline, the decreasing costs and increasing addition of renewable capacity, as well as migration of DISCOM consumers due to increased open access and captive options. In this context, the report traces the status of surplus power at the state level and capacity addition planning across states to understand causes for such surplus capacity and various efforts to manage the situation. The analysis also presents suggestions for a way forward to prevent such a predicament in the future. The report covers insights from states such as Madhya Pradesh, Gujarat, Punjab, Haryana, Rajasthan, Maharashtra, Andhra Pradesh and Telangana. The study shows that with the given capacity addition planned, DISCOMs will be facing sustained surplus and backing down in foreseeable future.

For over two decades, the sector has been struggling to address the two crucial issues of excessive transmission and distribution losses (including commercial losses) and excessive cross-subsidy in tariffs. This has severely affected financial viability of the entire sector. Unless urgent attention is given to the management of surplus power and more importantly, preventing build-up of more surplus capacity, this would become an equally significant challenge to the financial viability of the sector. The issue of surplus capacity would be more difficult to address as it involves huge capital investments, lock-in of scarce resources and long term legal contracts, often with private sector developers.

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