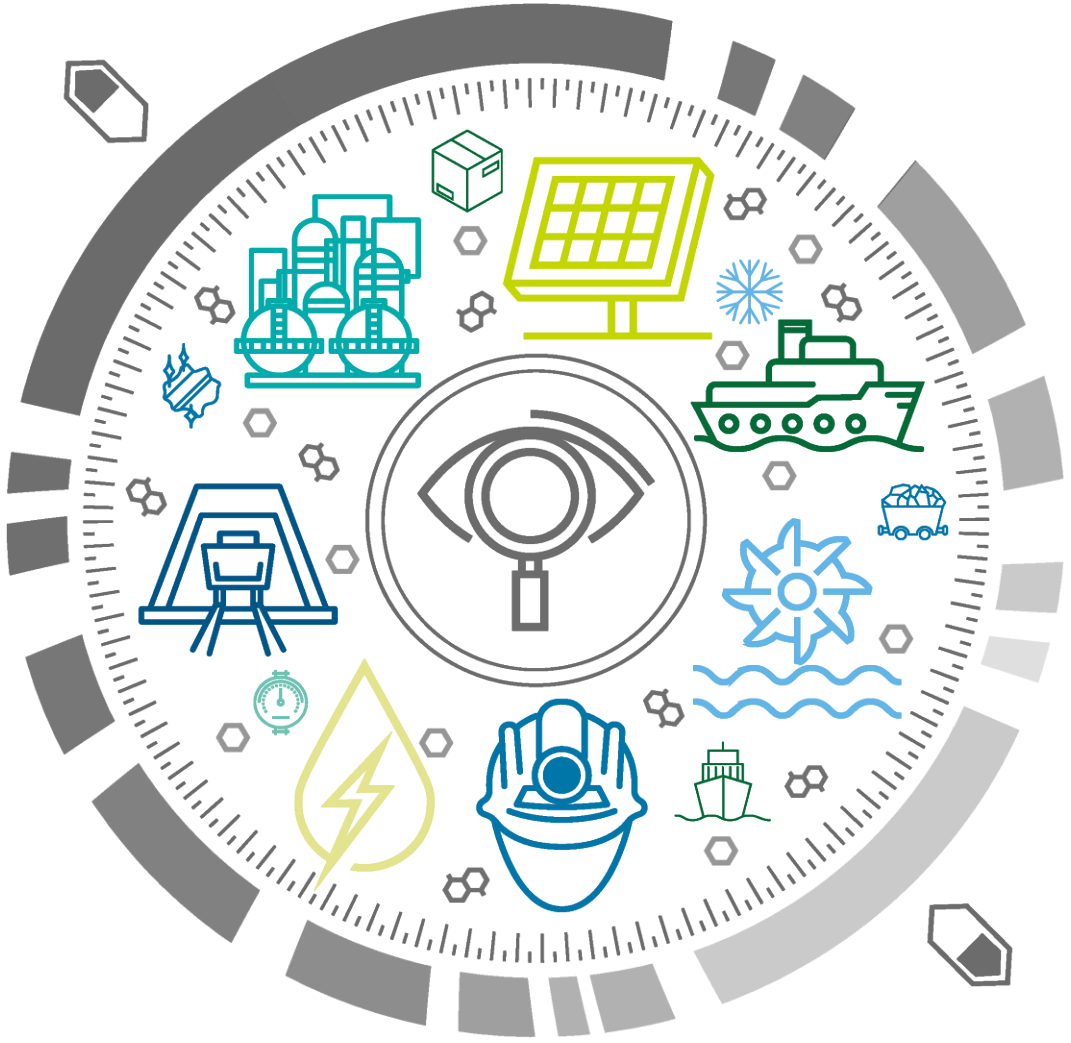
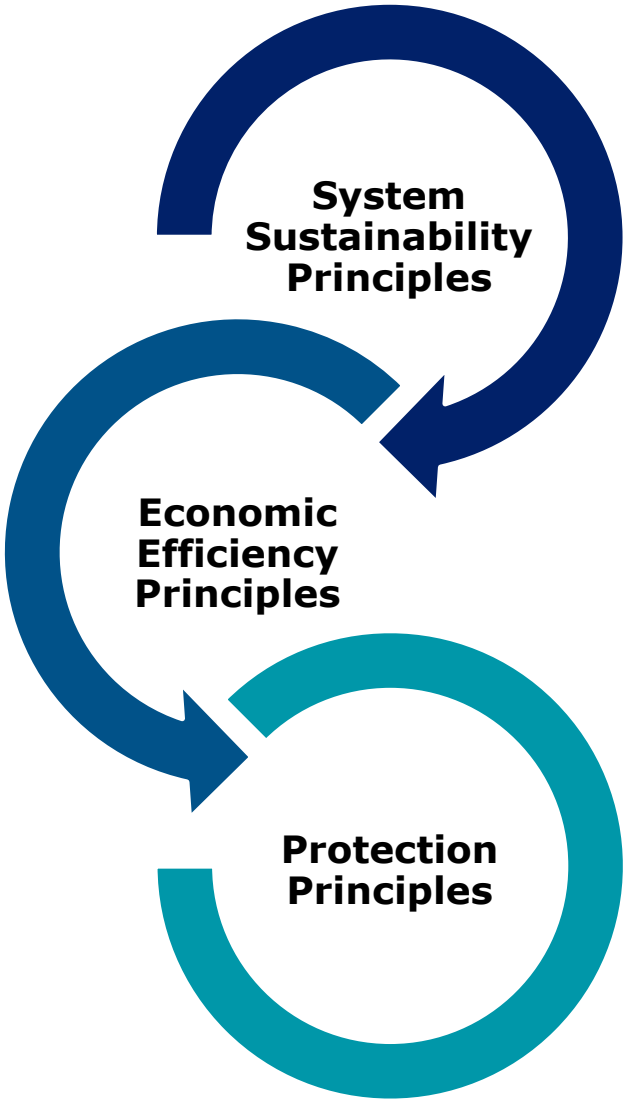


Tariff Principles and Design with a focus on ToD tariff and market based dynamic ToD

12th Capacity Building Workshop for officers of ERCs at IIT Kanpur

February 2019

Tariff Principles and their applicability

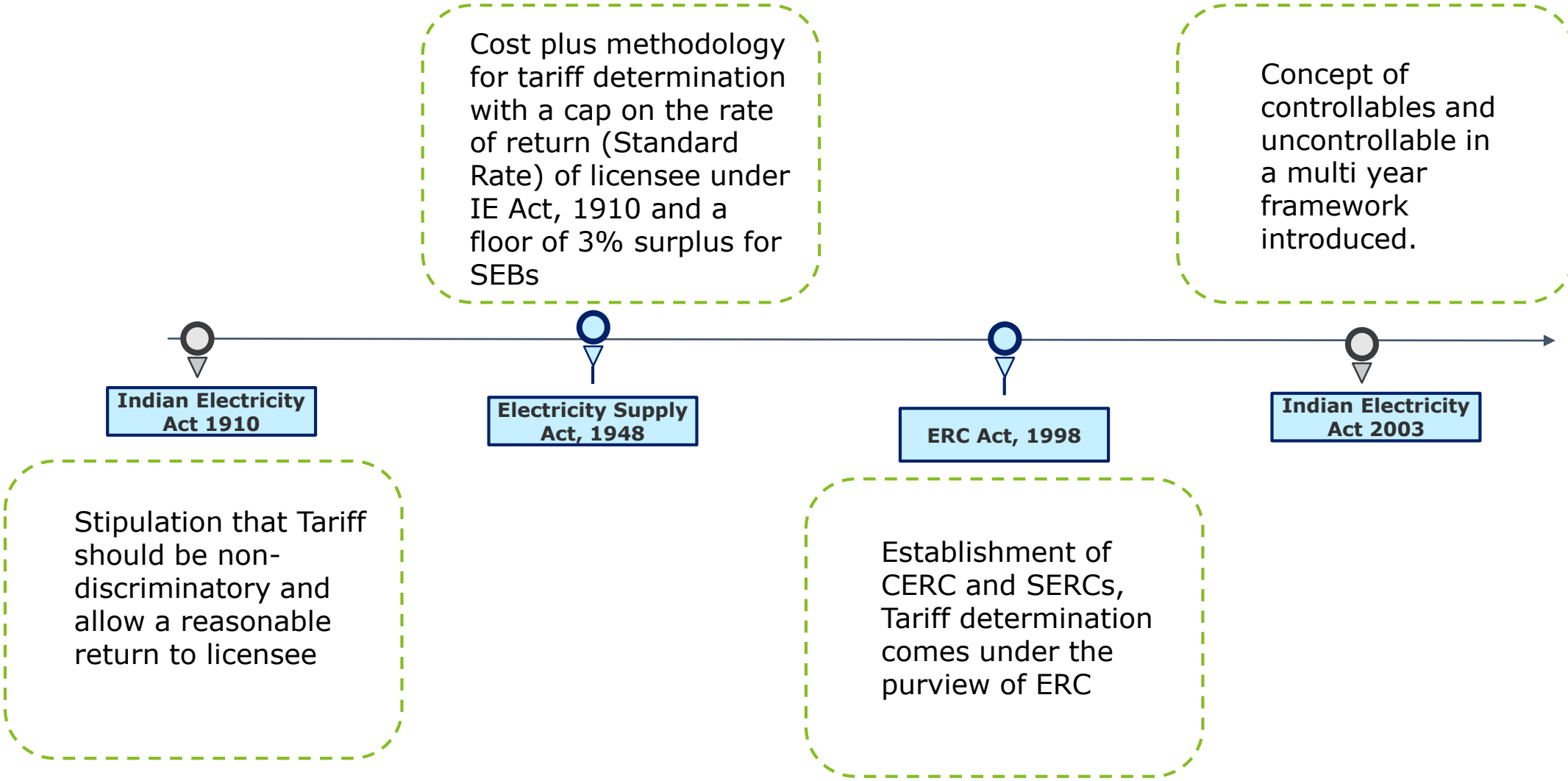


Sufficiency	• Network tariffs should allow the full recovery of efficient network costs and a reasonable return on capita
Achievability and adequacy of RoE	• Regulated rate of return should guarantee a return in line with the relative risk of the investments and financing conditions
Achievability of the incentive components	• The incentive mechanism should pose achievable target
Additivity of components	• Various tariff components must add up to give the total revenue requirement to be recovered
Productive Efficiency (Network services delivered to consumers at the lowest possible cost)	• Infrastructure cost efficiency: tariff regulation should aim to incentivise efficient investment • Operational cost efficiency: tariffs regulation should aim to reduce operational (including administrative) costs
Allocative Efficiency (Tariff should incentivise the users to use the grid efficiently)	• Peak reduction: Network tariffs should promote peak demand management;aim to reduce infrastructure cost for peak demand • Flexibility - Tariffs should encourage system flexibility, e.g. distributed generation, demand response and energy efficiency
Cost Reflectiveness	• Consumers should be charged in accordance with the costs of the services
Transparency	• Methodology and results of tariff allocations should be published and available to network participants
Non-discrimination	• All users that belong to a certain category and demand the same network services should be charged the same
Equity	• Certain categories of users, like low income users, are charged a tariff which is lower than the cost of the services received
Simplicity	• Methodology and results of the tariff allocations should be easy to understand and implement

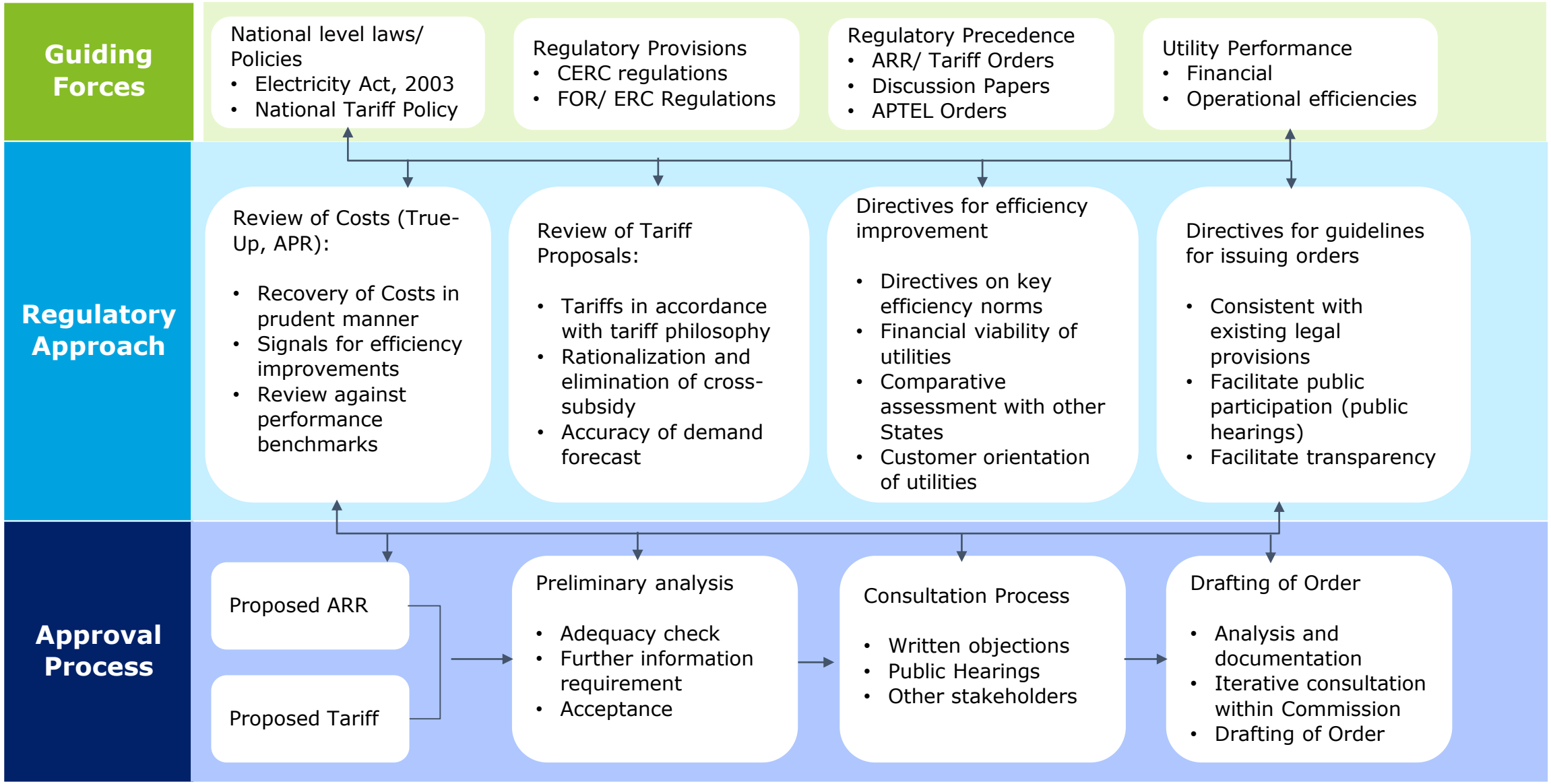
The multiple objectives belonging to the three sets described above are not always compatible with one another and in many cases present clear trade-offs that one should take into account while designing tariff.

Distribution Tariff

Evolution of tariff determination in India



Approach for tariff determination – MYT Framework



Methods for tariff determination

Model	Methodology	Limitations	Advantages
Cost of Service/ Rate of Return Regulation	Fixed return on rate base (capital) plus variable cost as pass through	• No incentive to reduce cost	• Predictable returns to utility • Fair as cost of service related to asset base
Performance Based Regulation	Performance benchmark set for both financial and operational criteria	• Extensive database required for benchmarking	• Provides maximum incentive to utility for performance improvement
RPI-X	Sets a price cap over tariff period which can be crossed only by Retail Price Inflation and discounted by efficiency factor	• Challenge in setting base year cost • Lack of continuity of inflation indices	• Allows flexibility to utility to incur costs and take actions

India moved from a cost plus regime to a hybrid tariff determination regime where targets are set for operational elements (Controllables) and other cost elements (Uncontrollable) are on cost plus basis.

Controllable and Uncontrollable Parameters

Concept of Multi-Year tariff advocated by Electricity Act to introduce certainty in tariff; Bifurcation of expenditure into controllables and uncontrolables

Uncontrollables

Cost of Power Purchase, Sales, Taxes & Duties, Change in Law, Force Majeure

- Any gain/ loss is passed on to the consumer

Controllables

AT&C Loss, Financing Charges, O&M, Capex

- Gain/Loss is shared with the consumers in a prescribed percentage

In addition, the ERC may stipulate trajectories for certain variables like distribution loss, collection efficiency, O&M Expense norms etc.

Controllable and Uncontrollable Parameters

Sales (Metered)	Sales (Un-metered)	Distribution Loss	Power Purchase Cost	Employee Cost	Repair and Maintenance	Admin & General	Financing Cost	Depreciation	IOWC
• CAGR of sales for last 3, 5 years • Econometric modeling with adjustments for consumers mix variation, inflection point in economic cycle, variation in audited findings	• An independent year long month-wise study by Licensee to assess unmetered consumption based on stratified sampling	• Establishment of baseline loss by the Commsision and loss reduction targets determined	• Comprehensive Power Purchase plan to be submitted in MYT Petition • Recovery allowed due to variation in fuel surcharge rate & requirement of incremental power	• Base norm escalated by inflation and adjusted by provisions for expenses beyond control of Licensee	• Percentage (based on norm) on GFA	• Base norm escalated by inflation and adjusted by provisions for expenses beyond control of Licensee	• Normative Debt Equity Ratio of 70:30 • Interest on loan based on weighted average rate on loan portfolio • Return on equity capped by Regulator	• Depreciation on 90% of original cost with residual value of 10%	• Allowed on normative basis including O&M expense, recievables, maintenance spares and security deposit from consumers

Tariff Rationalization

- **kVAh based tariff** – to motivate industrial and non-domestic consumers to maintain power factor. Consumers billed at kVAh (apparent energy) and not at kWh (active energy) whereby the reduction of reactive energy becomes the prerogative of the consumer

  Advantages: Complete recovery of costs of utility, Improvement of supply voltage, Periodic revision of penalty is not required

- **TOD Tariff –** Consumers charged dynamic price for electricity consumed during peak and off-peak period to reduce the negative slope in the load curve

  Advantage: Incentivizes consumers to shift demand to off peak period thereby reducing peak demand

- **Voltage wise tariff –** Allows a more accurate mapping of distribution losses to different voltage levels

  Advantage: Network losses of lower voltages are not passed on to higher voltages

Time of Day Tariff

Legal and Policy framework for ToD Tariff

The section 62 (3) of the Electricity Act 2003 says that:

> *"The Appropriate Commission shall not, while determining the tariff under this Act, show undue reference to any consumer of electricity but may differentiate according to the consumer's load factor, power factor, voltage, total consumption of electricity* ***during any specified period or the time at which the supply is required*** *or the geographical position of any area, the nature of supply and the purpose for which the supply is required"*

The provision no 5.4.9 of the National Electricity Policy also advocates the ToD tariff which says that

> *"The Act requires all consumers to be metered within two years. The SERCs may obtain from the Distribution Licensees their metering plans, approve these, and monitor the same. The SERCs should encourage use of pre-paid meters.* ***In the first instance, TOD meters for large consumers with a minimum load of one MVA are also to be encouraged.*** *The SERCs should also put in place independent third-party meter testing arrangements"*

NTP (8.4 Definition of tariff components and their applicability) envisages explicitly the emphasis on the ToD Tariff.

> *"Two-part tariffs featuring separate fixed and variable charges and* ***Time differentiated tariff shall be introduced on priority for large consumers*** *(say, consumers with demand exceeding 1 MW) within one year. This would also help in flattening the peak and implementing various energy conservation measures"*

Determination of TOD tariff for a Utility

Loading Pattern of Utility

Loading Pattern of Target category

Identification of peak and off peak hours

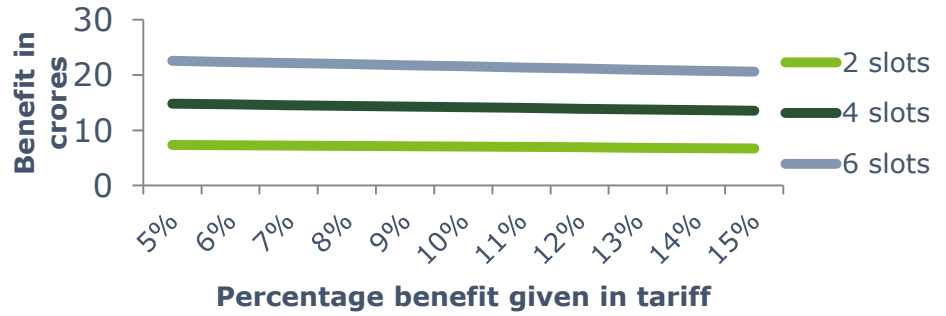
Pre-requisites for implementation of TOD tariffs

- Loading Pattern of the utility
- Category wise loading pattern
- Power Purchase Data
- TOD enabled meters
- Dyanmic Billing System
- MRIs

Key decision areas

Duration of peak/off-peak slot

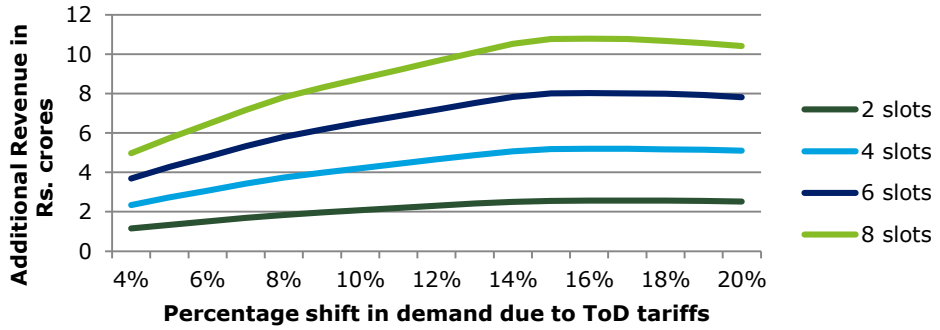
Larger the duration of peak slot, greater the shift in demand to off-peak



Incentive/penalty for time slots

Incentive/penalty needs to be determined based on the cost of power whose purchase is foregone in the peak period and the that of additional power purchase in the off peak period

Inventive/ penalty will determine the proportion of shift in demand which will in turn determine the commercial benefit to the utility.



Methodology to be followed

Collation of demand data of Utility

- Average demand for each of the 96 time blocks in a day recorded for the entire year
- Monthly average calculated each month
- Seasonal variation in demand curve estimated and analyzed

Identification of Peak/Off-Peak Hours

- Year segregated into two periods: Summer months and winter months
- Based on monthly average demand curves prepared, peak and off peak periods identified for each period

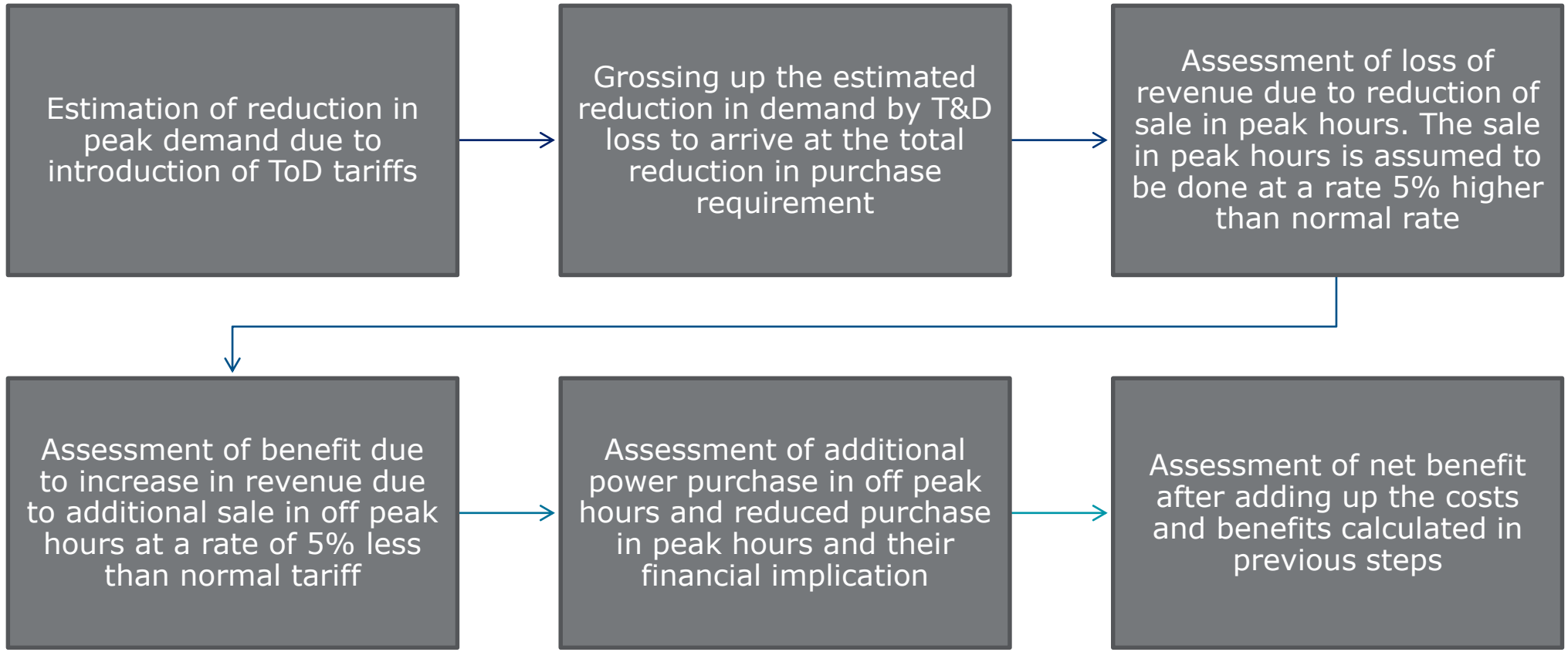
Assessment of HT demand (absence of meter data)

- Sanitization of feeders' data to identify evaluable feeders
- Average demand of all the identified industrial feeders calculated
- Average demand of feeders scaled up for entire HT industrial category

Cost benefit analysis of ToD implementation

- Estimation of costs and benefits on the basis of specific assumptions

Methodology for cost benefit analysis



Assumptions used for an illustrative analysis

- **HT loading pattern**: Load graph of sample HT feeders extrapolated to entire HTR category based on certain assumptions
- Utilization factor of HT category considered on the basis of actual data as recorded by Utility
- **Reduction/Shift in demand**: Scenario analysis for estimation of benefits depending on quantum of demand shift
- **Shift in consumption**: It has been assumed that due to ToD implementation there will only be a shift in demand from peak hours to off peak hours to reap maximum benefit
- **Peak and off peak hours**: For simplicity, as a starting point it may be assumed that duration of peak and off-peak hours is the same
- **Costs and benefits involved**:
    - Cost of additional power to be purchased during off peak hours due to shifting of load during off peak periods
    - Cost incurred due to reduction in sale (and consequent reduction in revenue) during peak hours
    - Benefits accrued as a result of reduction in the power purchase requirement during peak hours
    - Benefits accrued due to additional sale during off peak hours
- **Benefit of ToD**: After ToD implementation peak energy charges to be 5% higher than normal rates and off peak charges to be 5% lower than normal rates

Benefits and Cost associated with TOD implementation in the long run

Additional revenue/ Cost Reduction for Utility

- Additional revenue on account of TOD surcharge during peak hours
- Reduction in cost of power purchase due to reduction in peak consumption
- Revenue gain due to increase in sales during of peak hours (shifting of load from peak hours to peak)

Additional cost/ Revenue Loss for Utility

- Revenue loss due to reduction in sales during peak hours (after introduction of TOD Tariff)
- Revenue loss due to discount on existing sale during off peak hours
- Additional power purchase cost due to increase in demand during off peak hours

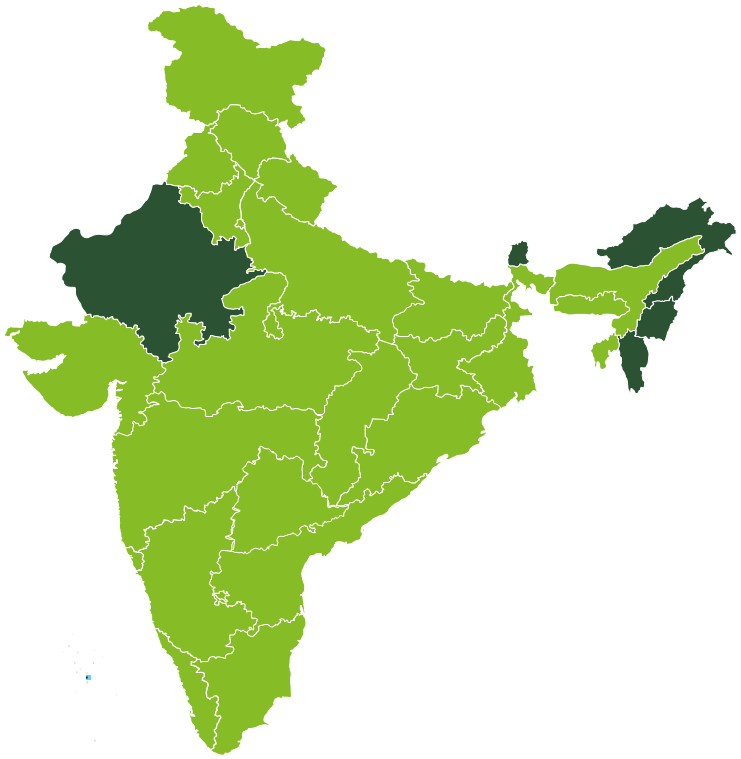
Illustration

Particular	Value	Unit
Load during Peak (LDP) – a	1,500	MW
Load relief during peak (LRDP) – b	150	MW
Energy Surcharge (ES) – c	0.25	INR/kWh
Discounted Tariff (DT) – d	4.75	INR/kWh
Additional Revenue due to TOD (RA) – e={(a-b)*c*NPH}	49,27,50,000	INR
Revenue Loss - reduced sales due to TOD (RL) – f={EC*NPH*b}	1,09,50,00,000	INR
Revenue Gain increased sales during off peak hours (RG) – g={b*d*NOPH}	1,04,02,50,000	INR
Existing Load during off peak (LDO) – h={LFO*TCL}	1,000	MW
Revenue loss due to discount on existing sale in off peak (RL) – i={h*(EC-d)*NOPH}	36,50,00,000	INR
Effective Power Purchase Rate (PPEP) (Peak Hours) – j={PAPP/(1-T&D Loss)}	5.08	INR/kWh
Savings in PP Cost (SP) – k={j*b*NPH}	1,11,30,87,675	INR
Effective Power Purchase Rate (PPEN) (Normal Hours) – L={PAPP/(1-T&D Loss)}	4.45	INR/kWh
Additional PP Cost (AP) in off-peak period – m={L*b*NOPH}	97,39,51,715	INR
Net Gain/Loss (NG) – n={e-f+g+k-n-i}	**21,21,35,959**	INR

Assumptions

Parameter	Value	Unit
Total Connected Load (TCL)	5000	MW
Load Factor (LFP)	30%	%
Load Factor (LFO)	20%	%
Load Relief Factor (LRF)	10%	%
Nominal Energy Charge (EC)	5	INR/kWh
Rate of TOD Surcharge (ROTS)	5.00%	%
Rate of TOD Rebate (ROTR)	5.00%	%
Number of Off Peak Hours (NOPH)	4	hrs
Number of Peak hours (NPH)	4	hrs
Normal Average Power Purchase Cost (NAPP)	3.5	INR/kWh
Peak Average Power Purchase Cost (PAPP)	4	INR/kWh
T&D Loss	21.3%	%
No. of Consumers Served (CS)	10,000	No.

Status of implementation of TOD tariff



TOD Implemented

TOD not implemented

Time of Day tariff in select states

Bihar	TOD tariff charges applicable to all HT consumers. Surcharge of 20%/ rebate of 15% applicable at peak and off peak periods on energy charges
Chhattisgarh	TOD tariff applicable to select HT consumers. Surcharge of 20%/ rebate of 25% applicable at peak and off peak periods on energy charges
Delhi	ToD tariff applicable on all consumers (other than Domestic) whose sanctioned load/MDI (whichever is higher) is 10kW/11kVA and above. Additionally, TOD optional for Domestic consumers. Surcharge/ Rebate applicable at 20% on Energy Charges
Gujarat	TOD tariff applicable to select HT consumers. Surcharge of 10%-20%/ during peak hours on energy charge. Night time concession available to consumers opting to use electricity exclusively during night time
Haryana	Optional TOD tariff applicable to HT Industrial customers from October to March. 19% surcharge and 15% rebate applicable on energy charges.
Jharkhand	TOD tariff applicable on HT consumers. 20% surcharge and 15% rebate applicable on energy charges.
Punjab	Additional charge of Rs. 2.00/kVAh during peak hours and rebate of Rs. 1.25/kVAh applicable during off peak hours for Medium and Large Industries, Non residential and bulk supply customers. Peak tariff is applicable only for months of June to September; off peak tariff is applicable for the rest of the year
Kerala	ToD Tariff applicable to EHT, HT and LT industrial consumers (with connected load of and above 20KW) Consumers. Surcharge of 50% and rebate of 25% applicable on energy charges during peak and off peak hours

Dynamic Time of Use (TOU) tariff – Market driven tariff

Real time pricing - Prices change on an hourly or sub-hourly , with price signals provided to the user shortly in advance, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level.

High risk and high reward for consumers

The UK Experience

While TOD tariff structures like Economy 7 and Economy 10 have been offered by suppliers in the UK since a long time, in 2018, Octopus Energy launched ToU tariff 'Octopus Agile' in February 2018 for their smart meter customers, providing them with 'dynamic' half-hourly price updates that reflect actual wholesale energy costs.

At 4pm every day, unit rates are updated for the next 24 hours. As the customer uses electricity, the charges are calculated based on half-hourly data from your smart meter.

The dynamic tariff includes the passing on of even negative prices (when the wholesale price goes below 0p/kWh), allowing customers to actually be paid to use electricity when demand is low, or when the grid is oversupplied by renewable power. Customers are alerted to this "*plunge pricing*" by text, email or online notifications.

THANK YOU

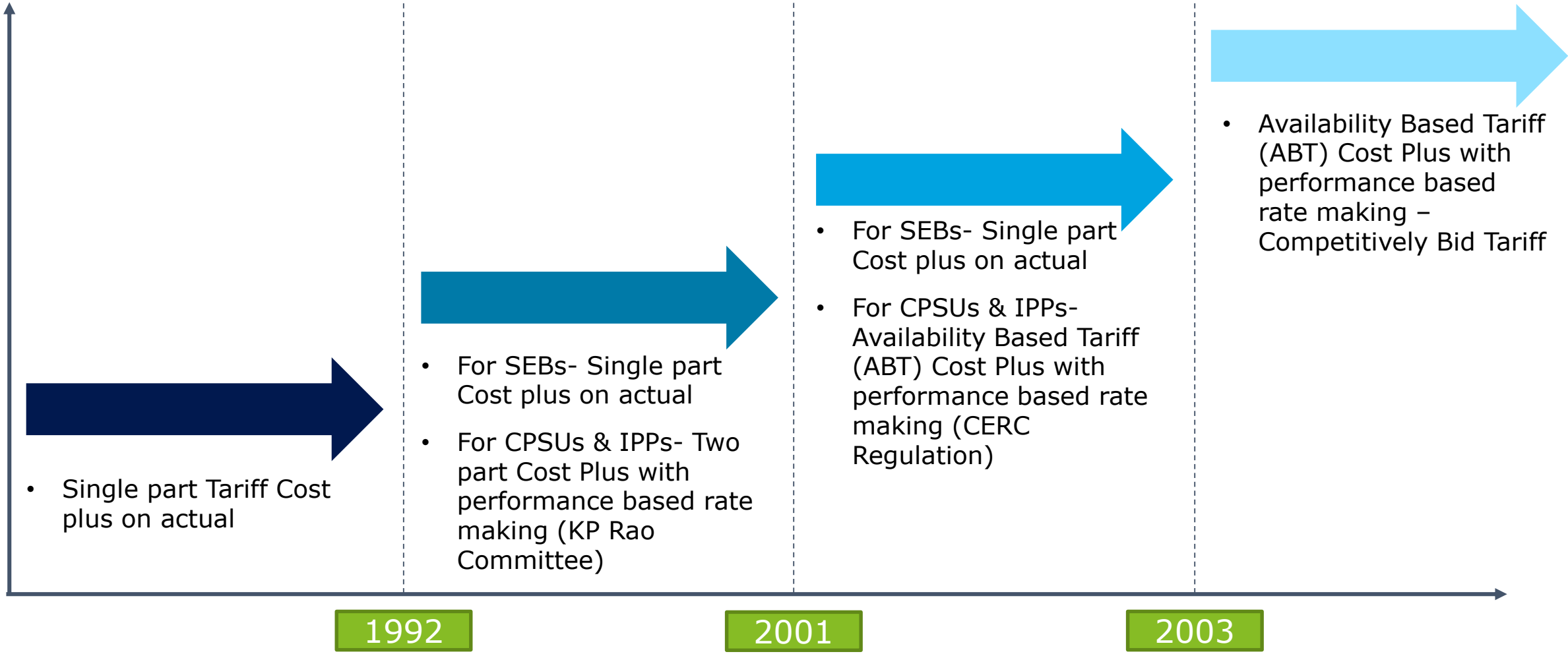
Detailed Methodology for cost benefit analysis of TOD implementation

- Compute the MW load during peak hours assuming various probable values of load factor (LF) during peak hours: ***MW load during peak (MWPL) = Load Factor (LF) x Total Connected Load***
- Compute the MW load during off peak hours assuming various probable values of load factor (LF) during off peak hours: ***MW load during peak (MWOPL) = Load Factor (LF) x Total Connected Load***
- Compute actual load relief (in MW) achieved during peak hours by implementing TOD tariff based on various probable values of load relief factor (LRF): ***MW load relief during peak (MWLR) = Load Relief Factor (LRF) x MWPL***
- Calculate peak hour energy surcharge per kWh (TOD surcharge in absolute term): ***Energy surcharge (ES) in paise/kWh = Rate of TOD surcharge x Nominal energy charge (EN) in paise/kWh***
- Calculate off peak hour energy rebate per kWh (TOD rebate in absolute term): ***Energy Rebate (ER) in paise/kWh = Rate of TOD rebate x Nominal energy charge (EN) in paise/kWh***
- Calculate additional revenue on account of TOD surcharge after implementation of TOD tariff: ***Additional Revenue (RA) (in Rs.) = (ES / 100) x (MWPL - MWLR) x (No of Peak Hours) x 365 x 1000***
- Calculate revenue loss due to reduced sales during peak hours on account of TOD tariff: ***Revenue Loss (RL) (in Rs.) = (EN / 100) x (MWLR) x (No of Peak Hours) x 365 x 1000***
- Calculate revenue gain due to increased sales during off peak hours on account of TOD tariff: ***Revenue Gain (RG) (in Rs.) = (EN-ER / 100) x (MWLR) x (No of off Peak Hours) x 365 x 1000***
- Calculate effective power purchase rate of costly power at consumer end considering T&D losses: ***Effective Power Purchase Rate (PPE & PPO) = Rate of Power Purchased in Peak or Off Peak Hours / [1- (T&D losses in %)]***
- Calculate saving in power purchase cost due to reduction in sales on account of TOD surcharge: ***Saving in power purchase cost (SP) (in Rs.) = (PPE / 100) x (MWLR) x (No of Peak Hours) x 365 x 1000***
- Calculate additional power purchase cost for off peak hours: ***Additional Power Purchase Cost (AP) (in Rs.) = (PPO/100)*MWLR*(No of off peak Hours) x 365 x 1000***
- Calculate revenue loss due to rebate in off peak hours (RLO): ***MW load during off peak (MWOPL) * (ER) * No of off peak hours x 365 x 1000***
- Calculate net gain/loss :***Net Gain (+)/Loss(-) (NGL) (in Rs.) = (RA) - (RL) + (RG) + (SP) + (AP) – (RLO)***

Generation Tariff Principles

Tariff Setting in India

Tariff Setting methodology has evolved over time



Recommendations of KP Rao Committee

Regarded as a landmark in history of tariff determination

Need for KP Rao Committee

- Prior to 1992, there were issues of shortage of power and difficulty in performing grid operations due to acute indiscipline shown by the generators as well as the beneficiaries.
- No defining principles were available for tariff setting
- Tariffs for individual stations were decided on the basis of mutual consent between the generator and the consuming SEBs
- Absence of mandatory norms for tariff setting delayed settlement of commercial terms
- Committee was formed to recommend alternative methods for the determination of generation tariffs of central stations

Major recommendations

1. The concept of two-part tariff, comprising fixed and variable charges respectively was accepted, though it was only implemented in part (for CPSUs and IPPs at that stage).
2. Efficiency enhancing changes were effected in the existing incentive structure – from recovery on PLF shifted to plant availability
3. Operational norms were determined for station heat rate, auxiliary power consumption, specific oil consumption. The norms were challenging relative to average performance levels at the time and hence laid the basis for performance based ratemaking.
4. Up to 100% foreign equity was permitted with foreign exchange risk protection.

Methods for Tariff Regulation

Different Methods of calculation of tariff

Method	Description
Rate of Return + Cost of Service	• Determination of allowable costs, a rate base and the rate of return to be allowed on the rate base. • Rate base is the capital amount on which a return is allowed. together with the variable costs incurred in the test year.
Performance Based Regulation	• Provides incentives for the utility to improve efficiency and reduce costs. • The return to the utility depends upon performance. • A form of PBR is in actual use in India, where tariffs are based on normative parameters.
Marginal Cost based Price	• Emphasizes future economic signals rather than relying on financial signals based on today's performance and historic financial costs. • Future cost of power which takes account of additional investments, etc.
RPI-X	• Imposes a price cap which, over the tariff period, can be crossed only to the extent of the retail price inflation (RPI). • This inflation rate is reduced by a pre-determined efficiency gain (X).
Competitive Bidding	• A market based approach • Successful adoption of this method presupposes the existence of competitive forces at the bidding stage

Availability Based Tariff

Cost plus with performance based rate making

- Availability means the **readiness of the generating station to deliver.**
- Defined as the **MW capability** of the generator for supplying to the grid **after accounting for the planned and unplanned outages and deration due to non-availability of auxiliaries, fuel and water**.

1	Capacity charges (fixed cost): full recovery at normative availability	Fixed cost elements are interest on loan, return on equity, depreciation, O&M expenses, taxes and interest on working capital
2	Energy charge (variable cost): up to scheduled energy, at normative tariff	Comprises of the variable cost (i.e.,fuel cost) of the power plant for generating energy as per the given schedule
3	Unscheduled Interchange/ DSM: deviation from schedule, rate linked to frequency	

- Payable depending upon what is deviated from the schedule
- Levied for difference in its Actual and Scheduled Generation/ drawl
- UI/ DSM charges linked to average frequency of 15 minutes time block.
- Recent DSM regulation links charges to ACP

Generation/Offtake	Payment of UI/ DSM
Generates more than schedule	Gets UI
Generates Less than schedule	Pays UI
Beneficiary overdraws power	Pays UI
Beneficiary Under draws power	Gets UI

RE Tariff

Regulated tariff to be determined on levellized basis

- As per RE Tariff Regulations-2012, tariff is determined on **levellised basis** for all RE technologies for the tariff period.
- Levellised tariff is calculated with appropriate discount rate representing weighted average cost of capital on the basis of normative debt-equity ratio

Approaches for Capital Cost Benchmarking

Regulatory Approach	Based on Norms as approved by various SERCs
Market Approach	Project awarded through competitive tender process
Actual Cost Approach	Information furnished by developers as a part of project appraisal requirements

Project Specific Tariff: Project specific tariff is determined by the Commission on case to case basis for new RE technologies

- Municipal Solid Waste and Refuse Derived Fuel based power projects (if a project developer opts for project specific tariff)
- Solar PV and Solar Thermal (if a project developer opts for project specific tariff)
- Hybrid Solar Thermal Power Projects
- Other Hybrid projects including renewable- renewable or renewable-conventional sources
- Biomass project other than that based on Rankine Cycle technology application with water cooled condenser
- Any other new renewable energy technologies approved by MNRE

Feed-in Tariff (FIT)

FIT is a policy tool encouraging deployment of RE technologies

- A renewable energy policy that **offers a guarantee of payment to renewable energy developers** for the electricity they produce
- It is regulator determined tariff for the price of RE by the cost plus approach
- Feed-In Tariffs are **index linked to inflation**
- Popular across the world with different names - Advanced Renewable Tariffs, Renewable Energy Payments, Renewable Energy Payments, Fixed Price Policies, Renewable & energy dividends, etc.

Tariff levels are usually guaranteed for a longer period 20 years or more

- *Longer contracts = lower initial tariff*
- *Shorter contracts = higher initial tariffs*

Standardized Contract (Model PPA)

In this way FiT provides long-term certainty about receiving financial support, which is considered to be lower investment risks

Differentiation in Feed-in Tariff

FIT varies with project characteristics viz. size, location and resource quality

Differentiation by Project Size

- Lowest payment level is typically offered to the largest plants
- Reflecting the gains that result from economies of scale
- Differentiating FiT payments by project size is another means of offering FiT payments that reflect actual project costs
- E.g.: France, Germany, Switzerland, and Italy provide the highest tariff amounts for the smallest PV installations

Differentiation by Project Location

- Varied payments to projects mounted in different physical locations (without regard to resource quality)
  - To encourage project development in particular applications
  - To encourage multi-functionality (e.g. solar PV)
  - Target particular owner types such as homeowners
  - To meet a number of other policy goals
- Eg. France

Differentiation by Resource Quality

- Different payments to projects in areas with a different cost of production
  - To encourage development in a wider variety of areas, which can bring a number of benefits both to the grid
  - To match the payment levels as closely as possible to RE generation costs
  - e.g. areas with a high-quality wind resource will produce more electricity from the same capital investment, all else being equal, leading to a lower levelized cost (FIT)
- Eg. Denmark, France, Germany, Portugal, and Switzerland have implemented resource adjusted payment levels

Hydro Tariff Structure

Annual Fixed Cost = Capacity Charge + Energy Charge

Recovery of tariff

50% of the Annual Fixed Cost is collected in the form of Capacity charge on monthly basis

50% of the AFC is divided by the Design energy net off of AUX to find out energy rate per unit

Energy rate so derived is multiplied with monthly scheduled energy to find out Energy charge per month

Incentive is inbuilt in the formulae and not provided separately

Transmission Tariff Principles

Transmission Tariff

Cost Components of a transmission tariff

Separate provisions for transmission tariff do not explicitly exist in any the electricity laws

Transmission Charges

The transmission charge payable for a calendar month for a transmission system or part thereof:

AFC x (NDM / NDY) x (TAFM / NATAF)

Where,

- AFC = Annual fixed cost specified for the year
- NATAF = Normative annual transmission availability factor, in %
- NDM = Number of days in the month
- NDY = Number of days in the year
- TAFM = Transmission system availability factor for the month, in %

Annual Fixed Cost

The **Annual Fixed Cost (AFC)** of a transmission system consists of the following components –

- Return on equity
- Interest on loan capital
- Depreciation
- Interest on working capital
- Operation and maintenance expenses