

Incentive-Based Regulation

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BOOK III APMA REGIONAL ENTREPRENEURSHIP CENTER



Incentive Regulation

- ✍ An incentive is any policy, rule, pricing mechanism, or procedure that seeks to modify the behavior of persons or firms by altering the marginal costs or marginal benefits associated with particular decisions.
- ✍ All regulation is incentive regulation of some kind, understand what incentives the chosen form of regulation is providing
- ✍ Incentive regulation tries to reward the utility with increased profits for reducing costs and improving service in a more pronounced fashion
- ✍ Select the metrics, set the baseline level, choose targets for improvement and/or maintenance and apply incentives/penalties

Cost of Service vs. Performance Based Regulation

- All forms of regulation modify behavior. Both cost of service and PBR are incentive mechanisms. The difference is in the kind of behavior they promote.
- PBR is not necessarily more powerful than COS; it depends on how the incentive mechanisms are set up.



Incentives in Traditional Regulation

- Revenue requirement of the utility = O&M expenses (including fuel) + Taxes + Depreciation + Rate base * allowed rate of return
- Profits = Revenues - Costs
- Typically rates are set for a future period based on expected sales, expenses and an authorized rate of return on capital
- To the extent the actual figures turn out to be different from forecasts, the actual earned return could be different from the authorized return
- If utility cuts expenses or increases revenues compared to forecasts, it can earn more than the authorized return. This creates an incentive for the utility to cut costs and/or increase sales.

Example 1

Volumetric Pricing

- **Forecast:**
 - Sales: 100 MWH
 - Cost: Variable: \$40/MWH, Fixed: \$5000 per year
 - Rate Base: \$10,000; Authorized return: 10% = \$1000
 - Revenue needed = $4000 + 5000 + 1000 = \$10,000$
 - Rate = \$100/MWH
- **Actual 1: (expenses lower by \$500)**
 - Sales: 100 MWH
 - Revenue = \$10,000 (100x100)
 - Cost: Variable: \$40/MWH, Fixed: \$4500
 - Actual return = $\$1500 / 10,000 = 15\%$ HIGHER

Example 1

Volumetric Pricing

- **Actual 2: (expenses higher by \$500)**
 - Sales: 100 MWH
 - Revenue = \$10,000 (100x100)
 - Cost: Variable: \$40/MWH, Fixed: \$5500
 - Actual return = $\$500/10,000 = 5\%$ LOWER
- **Actual 3: (sales lower by 10MWH)**
 - Sales: 90 MWH
 - Revenues: \$9000 (90x100)
 - Costs: \$8600 (90x40+5000)
 - Actual return: 4% (400/10000) LOWER

Example 1

Volumetric Pricing

- **Actual 4: (sales higher by 10MWH)**
 - Sales: 110 MWH
 - Revenues: \$11,000 (100x110)
 - Costs: \$9400 (110x40+5000)
 - Actual return: 16% (1600/10000) HIGHER
- **Actual 5: (expenses lower by \$500 sales higher by 10MWH)**
 - Sales: 110 MWH
 - Revenues: \$11,000 (100x110)
 - Costs: \$8900 (110x40+4500)
 - Actual return: 21% (2100/10000) HIGHER

Example 2

Marginal Pricing for Supply

- **Forecast:**

- Number of customers: 100 ; Sales: 100 MWH
- Cost: Variable: \$40/MWH, Fixed: \$5000 per year
- Rate Base: \$10,000; Authorized return: 10% = \$1000
- Revenue needed = $4000 + 5000 + 1000 = \$10,000$
- Rate = \$60/year per customer fixed charge + \$40/MWH

- **Actual 1: (expenses lower by \$500, same number of customers)**

- Sales: 100 MWH
- Revenue = \$10,000 ($60 \times 100 + 40 \times 100$)
- Cost: \$8500 ($40 \times 100 + 4500$; Variable: \$40/MWH, Fixed: \$4500)
- Actual return = $\$1500 / 10,000 = 15\%$ HIGHER

Example 2

Marginal Pricing

- **Actual 2: (expenses higher by \$500, same number of customers)**
 - Sales: 100 MWH
 - Revenue = \$10,000 (60x100 +40x100)
 - Cost: Variable: \$9500 (40x100 +5500; \$40/MWH, Fixed: \$5500)
 - Actual return = $\$500/10,000 = 5\%$ LOWER
- **Actual 3: (sales lower by 10MWH, same number of customers)**
 - Sales: 90 MWH
 - Revenues: \$9600 (6000+90x40)
 - Costs: \$8600 (90x40+5000)
 - Actual return: 10% (1000/10000) SAME

Example 2

Marginal Pricing

- **Actual 4: (sales higher by 10MWH, same number of customers)**
 - Sales: 110 MWH
 - Revenues: \$10,400 ($\$6000 + 40 \times 110$)
 - Costs: \$9400 ($110 \times 40 + 5000$)
 - Actual return: 10% ($1000/10000$) SAME
- **Actual 5: (sales lower by 10MWH, decreased number of customers)**
 - Sales: 90 MWH ; number of customers: 90
 - Revenues: \$9000 ($60 \times 90 + 40 \times 90$)
 - Costs: \$8600 ($40 \times 90 + 5000$)
 - Actual return: 4% ($400/10000$) LOWER

Concerns with Traditional Regulation

- **Heavy emphasis on historic accounting costs of utility in setting rates**
- **Little incentive for innovation on utility's part to reduce costs, particularly if cost increases are flowed through to customers, and the regulatory lag is small**
- **Utility productivity improvements captured for the benefit of customers quickly in the next rate case cycle thus dampening utility incentives to increase productivity**
- **As return is based on capital investment, skewed (and perhaps perverse) incentives to add fixed assets (the Averch-Johnson effect)**
- **Many uneconomic price signals due to cross subsidies**
- **Not much motivation to improve customer service quality**

Concerns with Traditional Regulation

- **Utility more responsive to regulators than to customers**
- **Regulators incur high costs to make informed appraisals of utility operations**
- **No penalties for failure to innovate**
- **No rewards for superior performance**
- **Unknown rules of the road for utility**
- **Dissatisfaction with traditional regulatory tools**
 - **Management audits of utilities**
 - **Prudence reviews of utility investments and operating practices**
 - **‘Used and useful’ test for new investments**

Concerns with Traditional Regulation

Now what?

- Monopolist often has a take it or leave it attitude
- Ideal is competition: suppliers make efforts to find out what customers want and try to meet those needs
- However, competition not feasible in natural monopoly areas - transmission and distribution;
- Competition perhaps feasible in other areas if certain criteria are met
- Regulation needed otherwise
- How about incentive based regulation?

Incentive Regulation and PBR

- PBR is expected to provide superior incentives to utilities compared to cost of service method.
- The incentives are tied to improvements in utility performance in price reduction and service quality improvement
- Less reliance on costs and more emphasis on prices; less relationship to earnings
- More reliance on external performance standards, less sensitive to company specific actions
- Sharing of benefit between utility and customer
- Customers benefit through lower price and improved service.
- Utility investors earn extra return on their investment.
- Some equate PBR primarily to Price caps

PBR Merits

Advantages

- May help improve plant utilization, reduce O&M expenses
- Reduce administrative costs of rate cases
- Improve system reliability
- Sets specific goals for utility management to focus on
- Can promote DSM, if those incentives are included
- Advancement of public policy initiatives
- Simulates competition where competition is not practical
- Superior return for superior performance
- Rules of the road better known up front
- Reduced risk of prudence disallowance
- Greater flexibility for utilities

PBR Merits

Disadvantages

- By reducing O&M costs, plant may not be adequately maintained
- Incentives on certain items may focus management attention on those at the risk of other important areas
- Lower reliability if maintenance programs are cut too far
- The benchmarks, targets may be wrong and may benefit the utility or customer to the disadvantage of the other party
- Regulatory risk; regulator may take away excess earnings in an unfair manner to the utility
- The more the consequences are based on external measures, it increases utility business risk
- Greater risk raises cost of funds

Is PBR a new concept?

- **PBR is not a completely new concept**
- **In the past, traditional ratemaking, at times, included some incentive provisions for utilities.**

For example:

- **Fuel efficiency incentives**
- **Decoupling sales and profits to reduce disincentive for DSM**
- **Rate case stay-outs and rate freezes for an extended period**
- **Rate plans associated with generation plant construction costs**

Building a PBR

- **Define goals of the system**
 - What do we want to encourage and discourage?
 - How do we want to allocate risks between customers and investors?
 - What types of protective measures do we want?
- **Develop structure of PBR**
 - Understand the incentives in the current system and how the modified system affects them
 - The structure/mechanism implements goals
 - Example: focus on prices, revenues, bills sends different signals
- **Get the numbers right**
 - Makes it fair and sustainable

Goals of PBR

- **The goals for PBR could include:**
 - **Improve efficiency and performance of utility**
 - **Improve incentives and remove disincentives for utility cost reduction**
 - **Simplify and streamline the regulatory process**
 - **Allow a reasonable opportunity for utility to earn extra returns for performance**
 - **Maintain and improve quality of service**

PBR Dimensions

- Time period of the plan (3 years, 5 years etc.)
- Product or service baskets for which PBR applied (total utility, by customer class, generation vs distribution etc.)
- Initial prices and target prices
- Inflation, productivity adjustments (I, X factors)
- Frequency of updates (annual or more periodic)
- Automatic clauses
- External uncontrollable factors (Z factors)
- Performance measures (Q factors)
- Treatment of earnings
- Reevaluation period
- Other conditions

Generation PBR

- Regulation will be needed during transition until there is a competitive market in generation
- Even in countries/states where generation is deregulated (limited price control), there is concern that the market is not competitive. Regulation is needed in South Asia as a competitive market for generation is not likely to develop soon
- Generation constitutes a major portion of the cost structure of the utility, customer bill
- Incentives to reduce both capital and operating costs
- Incentives to increase availability of generation

Distribution PBR

- Distribution utility touches the customer
- After generation, distribution (including, metering, billing and collections and customer service) is the biggest cost element in the utility cost structure
- Distribution PBR is more needed in some countries because that is where the management is inefficient

Why Distribution FRN.

(from ABC electric utility's statement)

- **Benefits to customers:**
 - Increased price stability
 - Sharing of cost savings
 - Quality of Service
 - Environmental Protection
- **Benefits to shareholders:**
 - Reduced regulatory burden
 - Maintain system reliability and safety
 - Potential to increase income based on performance
 - Cost effective
 - Change of employee mindset
- **Attributes**
 - Simplicity
 - Fairness
 - Service Quality
 - Appropriate Motivation
 - Flexibility
 - Sustainability



Structural Options and Key Elements of PBR

- **Common Elements**
 - **Sharing and Deadbands**
 - **Indexing or Yardstick**
 - **X factors**
 - **Z factors**
 - **Q factors**
- **Structural Options**
 - **Price Cap**
 - **Revenue Cap**
 - **Hybrid**
 - **Scope**
 - **Duration**

200 THE AFRICA REGIONAL INFRASTRUCTURE UNIT



Benchmark Regulation

- Benchmarking concept is common in the competitive markets
- Yardstick must be external, not internal cost based, to yield good incentives
- Tradeoff between simplicity and correct cost drivers; wrong index can create windfalls
- Index - CPI, GNP, PPI, or more focused utility cost related basket could be chosen
- Yardstick - Peer group, while ideal to use as a proxy, is very difficult to construct in practice; utilities vary in customer mix, fuel source mix, climate, financing etc.

Incentives

- **Regulatory Lag**
- **Earnings Sharing Mechanism**
- **Supply Costs**
- **Fuel Costs**
- **Demand Side Management**
- **Supply portfolio mix**
- **Service Quality**
- **Marginal Profits**

Regulatory Lag

- **The incentive arises out of delaying the introduction of new rates; the benefits of cost cutting and margins from increased sales will be kept by the utility for a longer period.**
- **The larger size of the benefit might induce the management to take actions that they would not otherwise take if the benefits are captured by the regulator for the benefit of customers**

Regulatory Lag

Example

- **Forecast:**

- Sales: 100 MWH
- Cost: Variable: \$40/MWH, Fixed: \$5000 per year
- Rate Base: \$10,000; Authorized return: 10% = \$1000
- Revenue needed = $4000 + 5000 + 1000 = \$10,000$
- Rate = \$100/MWH

- **Actual 1: (reduced expenses)**

- Revenue = \$10,000 (100x100)
- Sales: 100 MWH
- Cost: Variable: \$40/MWH, Fixed: \$4500
- Actual return = $\$1500 / 10,000 = 15\%$ HIGHER

Regulatory Lag

Example (contd)

- **Alternative A: Return in year 2 the savings to customers resulting from reduced utility costs**
 - then in year 2, all else equal, utility revenue needed would be \$9500 ($100 \times 40 + 4500 + 1000$)
 - the new rate for customers would be \$95/MWH
 - utility essentially saved \$500 for its owners
- **Alternative B: keep the rates good for three years**
 - then in years 2 and 3, all else equal, the rate will remain at \$100/MWH
 - utility gets to keep the \$500 for three years, for a total of \$1500 (not counting time value of money)
 - the new rate for customers in year four would be \$95/MWH.

Regulatory Lag

Example (contd)

- If alternate B is chosen, in theory, customers have 'lost' \$1000 worth of benefits (\$500/yearx2)
- So should we have pursued alternate A?
- It depends. It is possible that the utility would not have worked hard to save \$500 per year, if it was allowed to keep the savings for just one year. However, the \$1500 savings might be enough for it to take the actions that it took to cut costs.

Regulatory Lag

Example (contd)

- If we chose alternative A, and assuming the utility cut only \$100 in costs, customers would have gotten \$200 more for two years (assuming two more rate cases). However, they would have lost out \$500 per year for year four and beyond.
- The conventional wisdom is that regulatory lag enhances the incentive for utilities to cut costs more (we will discuss the side effects of such an action later).
- Recently, new rate plans are being set up for delivery companies for 3-10 year duration (along with other bells and whistles).

Earnings Sharing Mechanism

- The mechanism determines how much of the excess earnings (actual - sharing threshold level) of a utility should be shared between customers and shareholders.
- A pure economic incentive is not to cap the earnings at all; all excess earnings will be kept by the utility; provides the strongest motivation to cut costs
- Any cap or sharing blunts the incentive to some extent; however, caps or sharing are needed to protect customers from windfall profits to utility and to get buy-in from stakeholders

Earnings Sharing Mechanism

Example

- Remember the income statement

Sales	\$10,000
COGS	\$ 8,000
EBIT	\$ 2,000
Interest	\$ 500
EBT	\$ 1,500
Tax (40%)	\$ 600
Earnings	\$ 900

- Say the utility cut costs worth \$500. Its earnings would increase by \$300, all else equal.

Earnings Sharing Mechanism

Example (contd)

- **Alternate A: No sharing with customer**
 - utility keeps \$300
- **Alternate B: There is a 50/50 sharing with customer of all excess earnings**
 - utility keeps only \$150 and returns to customers \$150
- **Which provides a better incentive to the utility?**
- **Alternate C: add dead bands, sliding scale etc.**
- **Add regulatory lag to this example. How do the incentives then work?**

Supply Costs

- **Supply costs include cost of fuel, variable O&M, return on and of capital, other fixed costs**
- **Before a plant is put in rate base, regulators need to decide what is the right amount**
- **Regulators could provide an incentive mechanism as the plant is being built or conduct prudence investigations after the fact and disallow imprudent expenditures**

Supply Costs

Example

- A 1100 MW nuclear power plant was built at over \$6 Billion; however, only \$4.5B was allowed in the rate base. The rest was considered imprudent based on comparable costs of similar plants being built elsewhere.
- An incentive signal up front could be that only 50% of costs over \$3B will be allowed; and none over \$4.5B will be placed in rate base.
- The methodology of determining such incentives is very controversial. There is also debate on the role of regulator, whether to provide any assurances up front or to just resort to prudence review after the fact.

Supply Costs

- Once a plant is in rate base, what is an appropriate level of capital additions each year?
- What is an appropriate level of fuel and O&M costs?
- Should we do incentives piece meal or for total costs?
- Should we simply look at its own past performance to set future targets or compare with peers?

Supply Costs

Fuel Costs

- **Straight pass-through fuel adjustment clause: disincentives**
 - Removes incentive for generating efficiency
 - Skews tradeoff between capital and operating cost
 - Reduces incentive for diverse fuel mix
- **Incentive should be to maximize fuel efficiency and minimize fuel cost**
- **An incentive could be not to provide a full pass through but tie it to performance**
- **Incentives could be tied to heat rate, fuel cost elements**
 - Fixed BTU/kwh set in a case
 - Percentage pass through of fuel price variation

Supply Costs

Fuel Costs: Example

- **Allow the utility to collect revenue based on projected heat rate**
 - if utility improves heat rate, it keeps the associated benefits of lower fuel costs
 - if utility has a higher heat rate, it suffers the penalty of higher fuel cost
 - only a part of the variation could be passed through to customers
- **Example: The projected rate year heat rate is 9000 Btu/kwh; based on this, the fuel cost in the rate year is expected to be \$5M.**
 - If the actual heat rate is 8550 BTU/kwh, then the fuel costs would be \$4.75M. The utility could keep all of the savings (\$0.25M), or pass on some percentage to customers. The higher the percentage the utility keeps, higher its incentive to improve.
 - If the actual heat rate is 9450 Btu/kwh, then the fuel costs would be \$5.25M. The utility could pass on none of the incremental cost to customers, or pass on some of it to customers. The less it can pass on to customers, the more the incentive for the utility to keep costs down.

Supply Costs

- **One could set incentives for input fuel cost procurement (coal, oil, natural gas etc.)**
- **One could set incentives for capacity factor, plant availability, outage rates etc.**
- **One could set incentives for total supply costs - the incentive mechanism could be based on level of rate or rate of change.**

Supply Cost

Example

- **Level of Rate (price per unit):** Compare utility supply price to average, national or regional levels and expect cost cutting to bring toward average
 - Utility X's price per unit is Rs 4/unit, while the peer average is Rs 3/unit; a utility X to bring price down to Rs 3/unit over a period of time
- **Rate of Change: Reward/penalize company for changes in unit cost index relative to peer group**
 - Utility X's price per unit is Rs 4/unit, while the peer group price is Rs 3/unit
 - if both go up 10% next period, no incentive or penalty;
 - if peer group price stays the same but X's price goes down by 10%, then reward
 - if peer group price stays the same but X's price goes up by 10%, then penalty
- **These mechanisms are not easy to construct; lot of data needed for normalization to make sure we are comparing "apples to apples."**

DSM Incentives

- **Incentives for utilities to invest in cost-effective DSM programs; in the form of**
 - Higher return on equity
 - More certain cost recovery (of DSM costs as well as “lost revenues”)
 - Shared savings of benefits of DSM
- **Remove ratemaking disincentives for implementing DSM (depending on the rate design, the less a utility sells the less profit a utility makes; this acts as a disincentive to the utility to promote DSM that reduces usage)**

Supply Portfolio Incentives

- **Incentives provided to affect the supply portfolio mix**
 - **consideration of generation and DSM on level playing field**
 - **promotion of certain fuel sources (e.g., renewable energy)**
 - **incentives provided in the form of**
 - **higher rate of return**
 - **more certain cost recovery**
 - **penalties for non-performance**

Service Quality

- **Price cap could provide incentive to reduce service quality**
- **Add incentive/penalty provisions for utility to maintain or improve service quality**
 - **Reliability: SAIFI, CAIDI, MAIFI**
 - **Customer service: Customer satisfaction, Complaints to ERC, Internal utility measures such as billing accuracy, new service installations, appointments kept etc.**
 - **Employee, Customer Safety**
 - **Environmental Performance**

Marginal Profits

- **The strength of an incentive mechanism is measured by the marginal effect on utility profits and the length it takes to realize the benefit or incur the pain.**
- **Focus on marginal effect, not the absolute level of profits.**

Marginal Profits Example

	Base	Reduce costs	Reduce investment	FAC	Partial FAC
Rev	10,000	10,000	10,000	9,900	9,900
Costs	8,500	8,200	8,500	8,400	8,420
Operating Income	1,500	1,800	1,500	1,500	1,480
Tax	600	540	600	600	592
NOI	900	1,260	900	900	888
Equity	10,000	10,000	9,000	10,000	10,000
ROE	9.00	12.60	10.00	9.00	8.88
Change in Income		360	0	0	(12)

BOOK APPRAISAL REPORTS AND FINANCIAL STATEMENTS



$$I_{-t}$$

- The longer the lag the more the need for an index
- Must be external to yield good incentives
- Tradeoff between simplicity and correct cost drivers; wrong index can create windfalls
- Index -
 - Economy wide: CPI, GNP, PPI
 - Industry specific (labor, capital etc) factors
 - Peer price

X - Factors

- **Tied to productivity index**
 - Total Factor Productivity
 - Good indices on labor productivity, not much else
 - Informed by historical data
- **Can be positive or negative**

2000 THE APOLLO MICROFILM INTERNATIONAL/ALTAIR



Sharing and Deadbands

- **Under profit sharing plans**
 - **dead band in which company retains all cost savings, above that customers and utility share the saving**
 - e.g., allowed return 10%; sharing starts at 11.5%; 50/50 beyond 11.5%
 - **all savings go to customers or shareholders**
 - e.g., allowed return 10%; sharing starts at 11.5%; 100/0 customer/shareholder
 - **various permutations and combinations possible**
 - **symmetry issue**
 - **basis for the deadband**
- **Tradeoff**
 - **dulling of incentives if shareholders don't keep bulk of the savings**
 - **if customers don't share in the benefit - potential windfall for shareholders**
 - **if targets are set wrong, PR problems of customers not benefiting, and lack of fairness perception**

Price Cap Index

- Basic formula for price cap index
 - percentage change in PCI = $I_t - X_t + Z_t + Q_t$
 - I_t = external inflation measure
 - X_t = expected trend in total factor productivity
 - Z_t = exogenous events
 - Q_t = specific incentive/penalty provisions

SOUTH AFRICA REGIONAL INFRASTRUCTURE DEVELOPMENT



Contractual Terms (XYZ Electric)

- **Scope**
- **Performance Commitments, standards**
- **Consequences for non-performance**
- **Change Processes**
- **Restrictions**
- **Pricing**
- **Term**
- **End of term: renewal, re-negotiation**

Regulatory Issues with PBR

- An understanding between the utility and regulator about the PBR duration
- Supporting needed legislative changes
- Selling the plan to stakeholders
- No second-guessing, sticking to the plan
- Flexible pricing

Conclusions

- The power of PBR may be stronger or weaker than COS depending on the specific mechanism adopted
- Uncertainty undermines any PBR
- Decide and articulate goals
- Select right performance measures, indices must be external
- Get the structure and numbers right
- Look at a lot of numbers from a lot of perspectives; give extra weight to recent data; consider the future
- Establish baseline; set performance targets
- Set expectations and rules of the road
- Keep it simple
- Evaluate merits and drawbacks; ask the question: “compared to what”
- Evaluate plans and fix problems
- Buy-in and good understanding among stakeholders