A Brief Summary of Electric Ratemaking

Barbara R. Barkovich, Ph.D

Barkovich & Yap, Inc.

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The Revenue Requirement

- Capital assets go into rate base when they are used and useful
  - They earn a return, which is set in a Cost of Capital Case
  - They are depreciated
  - These items are reviewed in general rate cases, although large additions may warrant a separate filing
- Expensed items are recovered without a return

Costs of Utility Generation,Billing and Metering, and DR

- The revenue requirement for utility-owned generation, excluding fuel, is reviewed in general rate cases every three years
  - This includes rate base and O&M
- The revenue requirement for utility metering and billing systems is reviewed in general rate cases
- There have been separate cases to approve AMI expenditures
- There have been separate cases to approve utility EE and DR expenditures, in three-year cycles

Fuel and Purchased Power

- There are annual Energy Resource Recovery Account (ERRA) proceedings to determine fuel and purchased power costs (except DWR) on a *forecast* basis
  - The revenue requirement is spread over forecast sales
  - Revenues are recovered through balancing accounts with future adjustments for revenue over- or under-recovery, which can be due to errors in forecasting costs or sales, including response to DR events
- Utilities may make trigger filings if actual revenues differ from forecast by more than 5%
- There are annual ex post reviews of past ERRA cases
- There are separate proceedings to allocate DWR revenue requirements
  - DWR does its own reasonableness review

Cost Allocation

- **Costs are separated into two main functional categories for CPUC allocation purposes**
  - **Generation-related (capacity and energy)**
  - **Distribution-related (distribution and customer)**
  - **Certain other costs are allocated separately, e.g. non-bypassable charges**
- **Cost allocation varies by service voltage**
  - **Sub-transmission customers do not use the distribution system**
  - **Losses vary by voltage**
- **Transmission revenue requirement, cost allocation and rates are determined by FERC**
- **Cost allocation methodologies are adopted every 3 years in phase 2 of general rate cases and then implemented every time there is a rate change**

Cost Allocation

- **Cost allocation for generation and distribution is based on relevant marginal costs times cost drivers**
  - **The revenue is then adjusted to meet the revenue requirement**
  - **If the marginal cost is less than the embedded cost, the rates will have to be set greater than marginal cost to recover enough revenue, and vice versa**
  - **In addition, if the nonbypassable charges (NBC) are recovered through volumetric rates, as they usually are, these will be added to the revenue recovered through volumetric (i.e. energy) charges**
  - **The end result will be that any attempt to set RTP will either have a significant adjustment to each per kWh charge or require recovery of the additional revenue for NBC and the difference between the marginal and embedded costs through some other means**

Cost Allocation

- Costs for allocation of generation capacity revenue are based on CT proxy for capacity which may be net of forecast revenue from sale of energy called gross margin
  - **the gross margin calculation is controversial and the matter has been settled**
  - **These costs are allocated to TOU period and season by LOLE**
  - **The cost driver for allocation is class/schedule coincident demand**
- Costs for allocation of generation energy revenue are based on forecast of forward energy prices and production simulation of market clearing prices
  - **The cost driver is class/schedule energy use by TOU period**
  - **SCE has proposed hourly MEC shape based on simulation study**
  - **Other utilities have shaped MEC using old PX hourly prices (!)**
  - **Hourly costs are grouped into TOU periods and costs are allocated based on forecast sales by class/schedule in those TOU periods, providing greater revenue stability**

Cost Allocation

- There is a separate cost allocation for non-bypassable charges, e.g. DWR Bond Charge, CARE, PPP, etc. This is true even though some of these costs are generation-related
  - CARE, nuclear decommissioning, and DWR Bond Charge are allocated on an equal cents per kWh basis
  - PPP charges are allocated on system average percentage basis
  - CSI and SGIP allocation has been settled as part of larger allocation; there is no adopted methodology
  - The allocation method for each of these is litigated in each GRC Phase 2 case and can be controversial

Rate Design

- Generation-related costs are recovered through demand and energy charges
  - Demand charges are only used for larger customers
  - Demand charges recover capacity-related costs and energy charges recover variable costs of generation
  - For smaller customers, demand charges are recovered through energy charges
  - Energy charges vary by TOU period based on old PX hourly price variation; this may change with MRTU
- Rates vary by service voltage
- Rates are set to recover the pre-determined revenue requirement and rate options are usually set to be revenue-neutral
  - if customer usage patterns change, the utility will recover the revenue shortfall the next year *unless* costs adjust precisely with usage;
  - this means that reduced usage compared to the forecast will lead to higher rates the following year *unless* costs adjust precisely with usage

Rate Design

- Utilities do studies for GRC Phase 2 cases to see if TOU periods should be changed
  - PG&E, SCE have 6-hour summer on-peak
  - SDG&E has 7-hour summer on-peak
  - There are no winter on-peak periods
- All utilities have seasonal rates
  - SDG&E is changing its summer season to May-October
  - SCE’s summer is June-Sept.
  - PG&E’s summer is May-October

Rate Design

- Customers over 200 kW have TOU rates
  - 100 kW for SDG&E
- There are optional TOU rates for most customers
- Most classes have optional CPP rates
- SCE has optional RTP-2 schedule, which has RTP proxy prices based on temperature
- SCE and PG&E have interruptible rates for large customers and A/C cycling; SCE has agricultural pump cycling
  - PG&E A/C cycling is new

Rate Design

- Residential rate design is constrained by baseline and AB 1X legislation
  - Baseline legislation directs increasing block rates
  - AB 1X precludes increases in first two tiers except for CSI recovery
- CARE rates are discounted for low income customers; amount of discount varies by utility

E-1 Unbundled

Energy Rates by Component ($ per kWh)

Generation:

Baseline Usage *	0.04714
101% - 130% of Baseline	0.05593
131% - 200% of Baseline	0.10834
201% - 300% of Baseline	0.15678
Over 300% of Baseline	0.18217

Distribution:*

Baseline Usage	0.03786
101% - 130% of Baseline	0.04490
131% - 200% of Baseline	0.08687
201% - 300% of Baseline	0.12567
Over 300% of Baseline	0.14600

Transmission* (all usage)	$0.01034
Transmission Rate Adjustments* (all usage)	($0.00026)
Reliability Services* (all usage)	$0.00078
Public Purpose Programs (all usage)	$0.01138
Nuclear Decommissioning (all usage)	$0.00027
Competition Transition Charges (all usage)	$0.00332
Energy Cost Recovery Amount (all usage)	$0.00318
Rate Red Bond Memo Acct (RRBMA)** (all usage)	($0.00163)
DWR Bond (all usage)	$0.00477

E-19

Total Customer/Meter Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage
Customer Charge Mandatory E-19 ($ per meter per day)	$13.55	$19.71	$39.43
Customer Charge Rate V ($ per meter per day)	$4.12	$4.12	$4.12
Customer Charge Rate W ($ per meter per day)	$3.98	$3.98	$3.98
Customer Charge Rate X ($ per meter per day)	$4.12	$4.12	$4.12
Optional Meter Data Access Charge ($ per meter per day)	$0.99	$0.99	$0.99
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$11.41	$10.30	$7.94
Maximum Part-Peak Demand Summer	$2.61	$2.36	$1.80
Maximum Demand Summer	$6.90	$5.90	$3.98
Maximum Part-Peak Demand Winter	$1.00	$0.75	$0.00
Maximum Demand Winter	$6.90	$5.90	$3.98
Total Energy Rates ($ per kWh)			
Peak Summer	0.13219	0.13175	0.09766
Part-Peak Summer	0.09096	0.08913	0.07853
Off-Peak Summer	0.07414	0.07076	0.06710
Part-Peak Winter	0.08116	0.07680	0.07160
Off-Peak Winter	0.07165	0.06744	0.06370
Average Rate Limiter ($/kWh in summer months)	0.20692	0.20692	0.20692
Power Factor Adjustment Rate ($/kWh/%)	0.00005	0.00005	0.00005

UNBUNDLING OF E-19	Secondary Voltage	Primary Voltage	Transmission Voltage
Demand Rates by Components ($ per kW)			
Generation:			
Maximum Peak Demand Summer	$7.93	$7.63	$7.94
Maximum Part-Peak Demand Summer	$1.69	$1.64	$1.80
Maximum Demand Summer	$0.00	$0.00	$0.00
Maximum Part-Peak Demand Winter	$0.00	$0.00	$0.00
Maximum Demand Winter	$0.00	$0.00	$0.00
Distribution:**			
Maximum Peak Demand Summer	$3.48	$2.67	$0.00
Maximum Part-Peak Demand Summer	$0.92	$0.72	$0.00
Maximum Demand Summer	$4.15	$3.15	$1.23
Maximum Part-Peak Demand Winter	$1.00	$0.75	$0.00
Maximum Demand Winter	$4.15	$3.15	$1.23
Transmission Maximum Demand*	$2.97	$2.97	$2.97
Reliability Services Maximum Demand*	($0.22)	($0.22)	($0.22)

Energy Charges by Components ($ per kWh)

Generation:			
Peak Summer	$0.09994	$0.10241	$0.07752
Part-Peak Summer	$0.06562	$0.06532	$0.05839
Off-Peak Summer	$0.05110	$0.04880	$0.04696
Part-Peak Winter	$0.05650	$0.05357	$0.05146
Off-Peak Winter	$0.04829	$0.04525	$0.04356
Distribution**:			
Peak Summer	$0.01151	$0.00923	$0.00000
Part-Peak Summer	$0.00460	$0.00370	$0.00000
Off-Peak Summer	$0.00230	$0.00185	$0.00000
Part-Peak Winter	$0.00392	$0.00312	$0.00000
Off-Peak Winter	$0.00262	$0.00208	$0.00000
Transmission Rate Adjustments* (all usage)	($0.00030)	($0.00030)	($0.00030)
Public Purpose Programs (all usage)	$0.01022	$0.00959	$0.00962
Nuclear Decommissioning (all usage)	$0.00027	$0.00027	$0.00027
Competition Transition Charge (all usage)	$0.00260	$0.00260	$0.00260
Energy Cost Recovery Amount (all usage)	$0.00318	$0.00318	$0.00318
DWR Bond (all usage)	$0.00477	$0.00477	$0.00477