Rate Design for DERs and Beneficial Electrification

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Outline

1. Utility Ratemaking Overview
2. Utility Ratemaking Process and Perils
3. Rate Design and DERs: Value of Solar/Net Metering
4. Rate Design and Beneficial Electrification: EVs
5. Key Take-Aways
Approximate Components of Electric Rates
Basic Rate Design Terminology

• **Customer Charge**: A monthly fixed charge that applies independent of consumption. Also called a Basic Charge, Standing Charge, Meter Charge.

• **Energy Charge**: A price per kWh; may be in more than one time period, or more than one block. May be seasonal, or time-varying.

• **Demand Charge**: A monthly fee based on the highest instantaneous usage rate (usually highest hour) during the month or year.
Terminology

- **kW**: kiloWatt - Measure of the magnitude of instantaneous electricity use, reflecting 1,000 watts of electricity.
- **kWh**: kiloWatt-hour - Measure of the amount of electricity usage; magnitude times duration.
- **CP**: Coincident Peak - Usage at the time of the system peak demand
- **NCP**: Non-Coincident Peak - Highest usage by the customer at any time during the month
Steps in Utility Ratemaking

Revenue Requirement

Functionalization
- Assign cost to appropriate utility function

Classification
- Classify functionalized costs to demand, energy, customer

Allocation
- Assign cost responsibility among customer classes

Rate Design
- Develop pricing method for recovering assigned costs
Utility Ratemaking Process and Perils
Utility Revenue Requirement

Revenue Requirement (aka Cost-of-Service) = Capital Investments (Cap-ex) + Operating Expenses (Op-ex)

Power Plants, Transmission Lines, Local Distribution System

Purchased Power, Fuel Costs, etc.
Utility Revenue Requirement: “The Capital Bias”

Revenue Requirement (aka Cost-of-Service) = Capital Investments (Cap-ex) + Operating Expenses (Op-ex)

“Rate Base” x Rate-of-Return (Interest on Shareholders’ “Loan”) = Pass-Through, No Rate-of-Return

$1 x 10% = $1.10

$1 = $1
Utility Revenue Requirement: Discourages DERs (RE, EE)

Revenue Requirement (aka Cost-of-Service) = Capital Investments (Cap-ex) + Operating Expenses (Op-ex)

Both reduce kWh sales => raises rates

DG = less need for cap-ex = lower earnings

EE = more op-ex & less need for cap-ex
Functionalization, Classification, and Allocation of Costs
Straight Fixed / Variable (SFV):

100% of the distribution system is classified as “customer-related”
Minimum System Method:

50% of the distribution system is classified as "customer-related"
Basic Customer Method:

Only customer-specific facilities are classified as “customer-related”
Comparing Cost Classification Methods

<table>
<thead>
<tr>
<th>Cost Category</th>
<th>Straight Fixed / Variable</th>
<th>Minimum System Method</th>
<th>Basic Customer Method</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$/month/customer</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Poles</td>
<td>$10</td>
<td>$5</td>
<td>$</td>
</tr>
<tr>
<td>Wires</td>
<td>$20</td>
<td>$10</td>
<td>$</td>
</tr>
<tr>
<td>Transformers</td>
<td>$10</td>
<td>$5</td>
<td>$</td>
</tr>
<tr>
<td>Services</td>
<td>$1</td>
<td>$1</td>
<td>$1</td>
</tr>
<tr>
<td>Meters</td>
<td>$1</td>
<td>$1</td>
<td>$1</td>
</tr>
<tr>
<td>Billing</td>
<td>$2</td>
<td>$2</td>
<td>$1</td>
</tr>
<tr>
<td>Customer Service</td>
<td>$2</td>
<td>$2</td>
<td>$1</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$46</strong></td>
<td><strong>$26</strong></td>
<td><strong>$4</strong></td>
</tr>
</tbody>
</table>
NCP Demand Charges Are Also Suspect
TVR/TOU Rates Offer Promise

• More equitable cost recovery
• Reduce peak demand
• Provide incentive for electric vehicle charging during off-peak hours
• Provide incentive for electric water heater controls or timers
• Provide benefit to low-use customers
• Better aligns the customer with the market
## Sample TVR/TOU Rate

<table>
<thead>
<tr>
<th>Georgia Power (Georgia)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Charge</td>
<td>$10.00/month</td>
</tr>
<tr>
<td>On-Peak (2 – 7 PM, Mon-Fri, June – September)</td>
<td>$0.2032/kWh</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>$0.0464/kWh</td>
</tr>
</tbody>
</table>

Plus $0.04 fuel and other tariff riders.
How Should Utility Ratemaking Be Done?

- Bad: Throughput Incentive (current)
- Better: Decoupling
- Best: Performance-Based Regulation
Principle #1

A customer should be allowed to connect to the grid for no more than the cost of connecting to the grid.
Principle #2

Customers should pay for the grid in proportion to how much they use the grid, and when they use the grid.
Principle #2

Customers should pay for the grid in proportion to how much they use the grid, and when they use the grid.
Principle #3

Customers delivering power to the grid should receive full and fair value—no more and no less.
3 Rate Design and DERs

Example: Value of Solar
Two Views of Cost Recovery

**Traditional Utility View**
DG customer “uses” the grid and should pay for it;

**Solar Advocate View**
Value of distributed resource is greater than the retail rate;
RMI 2014 Survey of VOS Studies: Average: $0.1672/kWh
Residential Solar Installations Through 2017 (MW-DC)

Notes: Based on central case scenario from Cole et al. (2016), which projects solar adoption in the contiguous United States (i.e., excludes Hawaii and Alaska). Penetration levels calculated from projected capacity based on estimated state-level capacity factors (NREL 2016) and retail sales projections developed by applying EMM-level growth rates from the Annual Energy Outlook 2016 reference case (EIA 2016a) to historical state-level retail sales data (EIA 2015e).

Figure 10. NREL-projected rooftop solar penetration levels in 2030

Cumulative to 2017
Q2 2017 Action on Net Metering, Rate Design, and Solar Ownership Policies

39 States + DC took action on distributed solar policy and rate design during Q2 2017
Basic Principles:

• Customers have a right to reduce their consumption of grid-supplied electricity with energy efficiency, demand response, storage, or DSG.

• Most studies have shown that the benefits of DSG equal or exceed costs to the utility or other customers where penetration is low.

• Separate rate classes for distributed energy resources (DER) customers are presumed to be discriminatory.

• Opportunities for DSG and other DER customers and developers to provide grid services (e.g. voltage & frequency regulation, VAR support) should be encouraged.

Consideration of Alternatives to NEM:

• Penetration level should be the leading threshold criteria for consideration of alternatives to NEM.

• Customers who installed solar under NEM should be grandfathered for a reasonable period of time. Customers have a reasonable expectation that rate structures (as opposed to rates themselves) will not change.

• Simplicity, Gradualism, and Predictability: Any future design should consider customer needs for simplicity and any changes should be applied gradually and predictably.

• Hold harmless policies should be in place for low-to-moderate income (LMI) customers.
Principles for the Evolution of Net Energy Metering and Rate Design

Guiding Principles for Solar Rate Design

• Rate design should seek to send clear price signals to customers that encourage sustainable, cost-effective investments in solar and complementary technologies.

• Rate design should not create barriers to the deployment of DSG or other DER technologies that can add value to the grid. Some rate designs (e.g. more steeply inverted block rates, time-varying rates) can encourage early adoption of and provide greater incentives for DER technology deployment.

• Fixed charges should be limited to recovery of strictly customer-related costs like service drop, billing, and metering.

• Rate designs that emphasize higher fixed or quasi-fixed (e.g. residential demand) charges than necessary do not reflect cost causation, disincentivize energy efficiency and conservation, and disproportionately impact low and moderate income (LMI) customers.

Guiding Principles for Alternative Compensation

• A fair value of solar (or “stacked benefit”) compensation rate can be considered for DSG exports, at higher penetration levels. Such value should be determined taking into account both short term and long term (life of system) benefits of DSG.

• Buy all/Sell all (BA/SA or “VOST”) compensation approaches should be at the option of the retail customer and not the only customer option.

• Critical considerations impacting system economics and the ability to finance include the frequency and effect of future changes to the value proposition.

• Solar specific surcharges such as installed capacity fees are discriminatory, impede DSG system economics, and impede deployment of other DER technologies.

The complete set of principles is available at https://www.seia.org/initiatives/principles-evolution-net-energy-metering-and-rate-design.
Recent State NEM and Rate Design Highlights

- **NEM Successor Tariffs** have been developed through legislation, litigation, and settlement in a number of states, including Arizona, Nevada, Utah, Texas with more to come. Some common themes include:
  - Strong grandfathering (~20 years) for existing customers is becoming the norm
  - Treatment of self-consumed generation as load reduction
  - Most state commissions have mostly rejected increased fixed charges and resi demand charges, but utility attempts continue
  - Time-of-use rates common but not universal for new solar customers
  - Wide range of methodologies to set compensation for solar exports to grid – all somewhat less than retail rate. Only NV ties directly to penetration

- **Duration of netting periods** – monthly, hourly, etc. – has become major issue in NEM successor tariff cases. Shorter netting periods deliver lower value to customers where the export compensation rate is less than the retail rate
  - September 1 Nevada PUC decision implementing AB 405 maintains monthly netting.
  - NY REV Phase 1 decision moves to hourly netting for customers over ~200 kw
  - Utah settlement between local advocates and RMP moves to 15-minute netting, requires new meters
  - APS settlement includes buried language authorizing instantaneous "netting." Only self-generation actually consumed on-site gets valued at the retail rate
SEIA Strategy to Ensure Strong “NEM 3.0”

- Achieve Workable Time of Use Rates
  - Earlier peak periods
  - Grandfathering
  - Solar + storage rates

- Fully Value Distributed Energy Resources
  - Create and use societal cost test
  - Ensure that locational values are fair
  - Create opportunities for providing grid services

- Avoid New Costs Borne by Distributed Solar
  - Avoid fixed charges
  - Ensure utilities do not saddle distributed energy resources with unnecessary grid modernization expenses
Promising Rate Design Trends for DERs

- TVR/TOU rates trend toward VOS
- "Value Stacking"
  - e.g., VOS studies, NY REV
- Load-shaping and ancillary services opportunities coming with digitization

- Less promising:
  - Efforts to boost fixed charges; taxing EVs, etc.
  - Limited access in capacity markets, RTO’s, and vertically-integrated regions
Rate Design and Beneficial Electrification

Example: Electric Vehicles
# Beneficial Electrification (BE) vs. Load Growth

1. Saves Consumers Money; New Services
2. Reduces Environmental Impacts
3. Enables Better Grid Management

*Especially integration of renewables*
**Rate Design Matters: Eversource Impedes Workplace EV Charging in Large Commercial**

<table>
<thead>
<tr>
<th>NCP Demand Charge</th>
<th>$13.75/kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Charge:</td>
<td>~$0.12/kWh</td>
</tr>
</tbody>
</table>

6.6 kW charger, 200 kWh/month:

$90 Demand + $24 energy = $114 =

= $0.57/kWh or $5.70/gallon equivalent
Rate Design Matters: SMUD Encourages Workplace EV Charging in Large Commercial

<table>
<thead>
<tr>
<th>Description</th>
<th>Rate (per kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NCP Demand Charge</td>
<td>$2.82/kW</td>
</tr>
<tr>
<td>CP Demand: (2 – 8 PM, summer)</td>
<td>$6.91/kW</td>
</tr>
<tr>
<td>Energy Charges</td>
<td></td>
</tr>
<tr>
<td>Off-Peak</td>
<td>$0.10</td>
</tr>
<tr>
<td>Mid-Peak</td>
<td>$0.13</td>
</tr>
<tr>
<td>On-Peak (2 – 8 PM, Summer)</td>
<td>$0.19</td>
</tr>
</tbody>
</table>

6.6 kW charger, 200 kWh/month:
$18.61 Demand + $23 energy = $42
= $0.21/kWh or $2.10/gallon equivalent

Source: Jim Lazar, RAP
Rate Design Also Influences *When* EVs Are Charged

Dallas/Ft Worth
(standard rates)

San Diego
(time-of-use rates)

Copied from: M.J. Bradley, 2017
5 Key Take-Aways on Rate Design
Key Take-Aways: Bad News, Good News

Bad News:
- Rate design matters; complex, but can’t ignore it
- NEM may not be ideal framing; may want VOS
- DG should pay *something* to help maintain the grid
- Concerted utility efforts to boost fixed and demand charges

Good News:
- Good rate design *can* encourage DERs/DG
- TVR/TOU is trending, and favors VOS
- Solar+Storage, other innovations, are growing
- Transactive markets will help greatly; future is bright
About RAP

The Regulatory Assistance Project (RAP)® is an independent, non-partisan, non-governmental organization dedicated to accelerating the transition to a clean, reliable, and efficient energy future.

Learn more about our work at raponline.org

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### Functionalization:
Divide revenue requirement among utility functions

<table>
<thead>
<tr>
<th>Two categories:</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Rate Base (interest, return)</td>
</tr>
<tr>
<td>• Expenses (incl. depreciation)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Generation</th>
<th>Transmission</th>
<th>Distribution</th>
<th>Customer</th>
<th>Lighting</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Fuel</td>
<td>• High voltage lines</td>
<td>• Substations</td>
<td>• Service drops</td>
<td>• Fixtures</td>
</tr>
<tr>
<td>• Power Plants</td>
<td>• Substations</td>
<td>• Primary lines</td>
<td>• Meters</td>
<td>• Brackets</td>
</tr>
<tr>
<td>• O&amp;M</td>
<td>• O&amp;M</td>
<td>• Transformers</td>
<td>• Billing</td>
<td>• Dedicated poles</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Poles</td>
<td>• Customer Service</td>
<td></td>
</tr>
</tbody>
</table>

Regulatory Assistance Project (RAP)®
Classification: Determine general drivers of cost

- Generation
- Transmission
- Distribution
- Customer

Usage

Energy kWh
Demand kW
Customer related

System Coincident Peak
Equipment Peak
Customer Max Demand

Peak Loads
Number, size and type of customers and connections
Building on BE to Secure Your Future: Disruptive Forces Transforming Electricity

Source: Chandu Visweswariah, Utopus Insights Inc.