RATE DESIGN ISSUES WITH SOLAR

Workshop for Utah Municipal Utilities

Presented by:
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Regulatory Assistance Project

June 27, 2017
GROUP DISCUSSION/ICEBREAKER

• What has your utility already changed compared with full net-metering?
• What changes are you currently considering?
• What percentage of your customers and load have solar today?
• Do YOU have solar PV on your own home?
ROOFTOP SOLAR WORKSHOPS FOR UTAH MUNICIPAL UTILITIES

Grid Impacts of Distributed Solar

Solar Valuation & Cost/Benefit Analyses

Rate Design & Solar

April 13

MAY 11

TODAY
OVERVIEW

• Rate Design Principles
• Basic Charges, Demand Charges, Energy Charges
• Break
• Approaches to pricing with solar
  – Full net metering with basic customer charges
  – Full net metering with higher customer charges
  – Partial net metering
  – Buy All / Sell All
• How the solar customer views things
SMART RATE DESIGN:

RATE DESIGN AS THOUGH THE FUTURE IS IMPORTANT
PRICING FOR DISTRIBUTED RESOURCES:

NET-METERING AND FEED-IN TARIFFS
RECOGNIZING UNIQUE COSTS AND BENEFITS OF DISTRIBUTED RESOURCES
THREE GUIDING PRINCIPLES FOR RATE DESIGN

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 and power supply in proportion to how much they use, and when they use it.
PRINCIPLE #2

Customers should pay for the grid and power supply in proportion to how much they use, and when they use it.
PRINCIPLE #3

Customers delivering services to the grid should receive full and fair value – no more and no less.
RATe Design Essentials

- Relationship between the Cost of Service Study and Rate Design
- Fixed Charges
- Demand Charges
- Time-of-Use (TOU) Energy Charges
- Impact of rate design
THE COST OF SERVICE STUDY

Revenue Requirement

Functionalization

Classification

Allocation

Accounting data categories

Assign cost to appropriate utility function

Classify functionalized costs to demand, energy, customer

Assign cost responsibility among customer classes
FIXED OR “CUSTOMER” CHARGES

• Monthly Fee to “be a customer”

• Typically $5 - $10/month, covering billing and collection only

• Utilities often seeking to include distribution system infrastructure costs in the fixed charge, e.g. $15 - $50/month
CUSTOMER-RELATED COSTS

- Generation
- Transmission
- Distribution
- Customer

- Energy kWh (by time period?)
- Demand kW (Various measures)

- Usage
- Peak Loads
- System Coincident Peak
- Equipment Peaks
- Customer Maximum Demand

- Number, Size & Type of Customers and Connections
BASIC CUSTOMER METHOD

ONLY CUSTOMER-SPECIFIC FACILITIES CLASSIFIED AS CUSTOMER-RELATED
MINIMUM SYSTEM METHOD:

~50% OF DISTRIBUTION SYSTEM CLASSIFIED AS CUSTOMER-RELATED
STRAIGHT FIXED / VARIABLE:

100% OF DISTRIBUTION SYSTEM CLASSIFIED AS CUSTOMER-RELATED
## COMPARING METHODS

<table>
<thead>
<tr>
<th>Cost Category</th>
<th>Basic Customer</th>
<th>Minimum System Method</th>
<th>Straight Fixed / Variable</th>
</tr>
</thead>
<tbody>
<tr>
<td>Poles</td>
<td>$ -</td>
<td>$5</td>
<td>$10</td>
</tr>
<tr>
<td>Wires</td>
<td>$ -</td>
<td>$10</td>
<td>$20</td>
</tr>
<tr>
<td>Transformers</td>
<td>$ -</td>
<td>$5</td>
<td>$10</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>$2</td>
</tr>
<tr>
<td>Customer Service</td>
<td>$2</td>
<td>$2</td>
<td>$2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$ 6</strong></td>
<td><strong>$ 26</strong></td>
<td><strong>$ 46</strong></td>
</tr>
</tbody>
</table>
These utilities serve one in six Americans.

<table>
<thead>
<tr>
<th>Customer Charges: Largest U.S. Utilities</th>
<th>State</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pacific Gas &amp; Electric Co.</td>
<td>CA</td>
<td>None</td>
</tr>
<tr>
<td>So Cal Edison</td>
<td>CA</td>
<td>$0.87</td>
</tr>
<tr>
<td>Public Service E&amp;G</td>
<td>NJ</td>
<td>$2.43</td>
</tr>
<tr>
<td>Detroit Edison Co</td>
<td>MI</td>
<td>$6.00</td>
</tr>
<tr>
<td>Virginia Electric Power</td>
<td>VA</td>
<td>$7.00</td>
</tr>
<tr>
<td>Florida Power &amp; Light Co</td>
<td>FL</td>
<td>$7.24</td>
</tr>
<tr>
<td>Georgia Power Co</td>
<td>GA</td>
<td>$9.00</td>
</tr>
<tr>
<td>Commonwealth Edison Co</td>
<td>IL</td>
<td>$15.06</td>
</tr>
<tr>
<td>Consolidated Edison</td>
<td>NY</td>
<td>$15.76</td>
</tr>
</tbody>
</table>
## EXAMPLE BASIC CHARGES WESTERN US

<table>
<thead>
<tr>
<th>Company</th>
<th>Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rocky Mountain Power Utah</td>
<td>$6.00</td>
</tr>
<tr>
<td>Rocky Mountain Power Idaho</td>
<td>$5.00</td>
</tr>
<tr>
<td>Avista Utilities Idaho</td>
<td>$5.75</td>
</tr>
<tr>
<td>Avista Washington</td>
<td>$8.50</td>
</tr>
<tr>
<td>Pacific Power Washington</td>
<td>$7.75</td>
</tr>
<tr>
<td>Puget Sound Energy WA</td>
<td>$7.87</td>
</tr>
<tr>
<td>Portland GE Oregon</td>
<td>$10.50</td>
</tr>
<tr>
<td>Idaho Power</td>
<td>$5.00</td>
</tr>
</tbody>
</table>
QUESTIONS TO ASK ON CUSTOMER CHARGES

• Do the costs really vary with the number of customers?
• If customers used only a tiny bit of power each month, would these costs be incurred?
• Do these costs vary between customers within a customer class?
• Do multi-family customers have different costs and rates than single-family?
• If one customer left the system, would these costs change?
• How will it affect customer bills?
THE GENESIS OF UTILITY PRICE REGULATION
GENESIS OF UTILITY REGULATION
HOW DO OTHER INDUSTRIES RECOVER FIXED COSTS?
WE PAY FOR OTHER “GRIDS” IN VOLUMETRIC PRICES
AND THEY ARE HAPPY TO HAVE OUR BUSINESS
WE’RE BEEN HERE ONCE BEFORE!
THE PHONE COMPANIES LOST HALF OF THEIR CUSTOMERS
COMPETITIVE ALTERNATIVES FOR PHONE SERVICE

$7/month
150 minutes

$15/month
Unlimited
BREAK FOR DISCUSSION
DISCUSSION QUESTIONS

• Are there any utilities in the room that don’t assess a fixed charge to residential customers?
• When was your last cost of service study?
• What methods were used (basic customer, minimum system, SFV, combination) to determine customer-related costs and fixed charges?
• Did you evaluate any specific costs of serving solar customers?
• Do you think your electric utility’s fixed costs should be recovered in fixed charges?
DEMAND CHARGES FOR SMALL USERS
DEMAND CHARGES

• Monthly fee based on the single highest rate of usage (1 hour or even 15 minutes) in a month
• Common for larger commercial and industrial consumers
• Seldom used for residential or small commercial
COINCIDENT AND NON-COINCIDENT DEMAND

• Coincident Demand: A customer’s usage at the time of the system maximum usage

• Non-Coincident Demand: A customer’s highest usage during the month
GENESIS OF DEMAND CHARGES

• 1890’s: Charged by connected load. No meters.

• 1920’s: Metering for kWh and maximum demand became common for large users.

• Metering for TOU was much more expensive until the smart meter.
DIVERSITY: A KEY ISSUE

• Many customers use system capacity at different times and can share system capacity:
  • Church: Nights and Weekends
  • Schools: 7 AM to 4 PM
  • Stadium Lighting: After dark on Friday

• Some pre-empt capacity continuously:
  • Denny’s
  • 24-hour Mini-marts
HIGH SCHOOL STADIUM LIGHTING: THE CARICATURE OF THE PROBLEM

**CP:** None

**NCP:** 1%

Load Factor
LOWER LOAD-FACTOR CUSTOMERS CAN SHARE CAPACITY

- Morning loads
- Evening loads
- 24/7 loads
- Both CP and NCP rates unfair to shared demand customers
WHY DEMAND CHARGES WORK POORLY FOR SMALLER CUSTOMERS

• Diversity
  – Early and late risers
  – Early and late returners
  – Morning and Evening Businesses
  – Customer peaks ≠ system peaks

• Apartments and Business Parks
  – Few people / meter
  – Many customers / transformer
  – Electric water heaters common
  – Utility sees only the combined load
INDIVIDUAL LOAD SHAPES VARY

Customer 1: 36% Load Factor

Customer 2: 44% Load Factor

Customer 3: 38% Load Factor

Individual Load Shapes
THE UTILITY SEES THE COMBINED LOAD OF MULTIPLE CUSTOMERS

Sum of NCP Demands: 6.5 kW
CP Demand: 4.0 kW
AN IMPORTANT CONCERN:
DEMAND CHARGES SHIFT COSTS TO OCCASIONAL USERS

• With $10/kW Demand Charge:

• Use 5 kW for 1 hour in month: $50
• Use 4 kW for 720 hours in month: $40
WHAT COSTS ARE ATTRIBUTABLE TO WHAT MEASURE OF “DEMAND?”

• System Capacity: Generation and high voltage transmission

• Class or Area Capacity: Distribution circuit, substation

• Customer Specific Capacity: Service drop, and perhaps the final line transformer
Generation based on TOU Energy

Shared Bulk Transmission Priced based on TOU energy and system peak

Shared Distribution Priced based on TOU energy and class peak

Customer-Specific Facilities Priced on a customer-specific basis
All customers should contribute to the recovery of capacity costs

The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity

Any service making exclusive use of capacity should be assigned 100% of the relevant cost;

The allocation of capacity costs should change gradually with changes in the pattern of usage;

More demand costs should be allocated to usage on-peak than off-peak;

Interruptible service should be allocated less capacity costs, but still contribute something;
ALL CUSTOMERS SHOULD CONTRIBUTE

• All customers should contribute to the recovery of capacity costs
  – CP demand imposes no cost on off-peak customers, giving them a free ride
  – NCP demand imposes some cost on all, but does not differentiate between on-peak and off-peak demands
  – TOU recovers some capacity costs in all hours, but concentrated in peak hours
DURATION OF DEMAND

• The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity
  – CP demand only measures one interval during highest-load hours
  – NCP demand treats 1 hour just like 720 hours
  – TOU apportions capacity cost across all hours
PRE-EMPTIVE CUSTOMERS PAY FULL COST

• Any service making exclusive use of capacity should be assigned 100% of the relevant cost
  – CP billing demands exceed system capacity, so costs are apportioned below full cost
  – NCP billing demands greatly exceed system capacity, so costs are apportioned below full cost
  – TOU rates assign exactly 100% of system costs to 8,760 hours per year; a customer using capacity
    8,760 hours pays the full cost
GRADUALISM

• The allocation of capacity costs should change gradually with changes in the pattern of usage
  – CP demand focuses on a narrow period; a customer who cuts use then avoids all costs
  – NCP measures any period; more likely to be erratic
  – TOU is proportionate the hours capacity is used, a very smooth gradual transition
CONCENTRATE ON PEAK PERIODS

• More demand costs should be allocated to usage on-peak than off-peak
  – CP assigns all costs on on-peak
  – NCP does not distinguish at all between on-peak and off-peak
  – TOU assigns more demand costs to usage on-peak than off-peak, but some costs apportioned to all periods
Interruptible service should be allocated less capacity costs, but still contribute something

- CP assigns zero cost to interruptible
- NCP assigns 100% of capacity costs to interruptible
- TOU recovers capacity cost proportionate to interruptible customer use of capacity in all hours
### GARFIELD AND LOVEJOY CRITERIA

**Exhibit 3. Garfield and Lovejoy Criteria and Alternative Rate Forms**

<table>
<thead>
<tr>
<th>Garfield and Lovejoy Criteria</th>
<th>CP Demand Charge</th>
<th>NCP Demand Charge</th>
<th>TOU Energy Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>All customers should contribute to the recovery of capacity costs.</td>
<td>N</td>
<td>Y</td>
<td>Y</td>
</tr>
<tr>
<td>The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity.</td>
<td>N</td>
<td>N</td>
<td>Y</td>
</tr>
<tr>
<td>Any service making exclusive use of capacity should be assigned 100% of the relevant cost.</td>
<td>Y</td>
<td>N</td>
<td>Y</td>
</tr>
<tr>
<td>The allocation of capacity costs should change gradually with changes in the pattern of usage.</td>
<td>N</td>
<td>N</td>
<td>Y</td>
</tr>
<tr>
<td>Allocation of costs to one class should not be affected by how remaining costs are allocated to other classes.</td>
<td>N</td>
<td>N</td>
<td>Y</td>
</tr>
<tr>
<td>More demand costs should be allocated to usage on-peak than off-peak.</td>
<td>Y</td>
<td>N</td>
<td>Y</td>
</tr>
<tr>
<td>Interruptible service should be allocated less capacity costs, but still contribute something.</td>
<td>Y</td>
<td>N</td>
<td>Y</td>
</tr>
</tbody>
</table>
CALIFORNIA: APPLICATION OF PRINCIPLES

• Complaint case brought by large customers of PG&E and SCE with PV
• Cloudy days were their individual peaks
• These were **NOT** system peaks
• Ruled that utility should shift **75% of demand charges into TOU energy charges**

• Docket: 12-12-002    Decided 12/18/14
## SACRAMENTO: ADDRESSING THE CONCERN FOR LARGE COMMERCIAL USERS

<table>
<thead>
<tr>
<th>Sacramento Municipal Utility District</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed Charge</td>
<td>$/month</td>
<td>$106.85</td>
</tr>
<tr>
<td>Demand Charges</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Distribution Capacity</td>
<td>$/kW</td>
<td>$2.82</td>
</tr>
<tr>
<td>2PM - 8 PM Surcharge</td>
<td>$/kW</td>
<td>$6.91</td>
</tr>
<tr>
<td>Energy Charges</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Super-Peak 2 - 8 PM</td>
<td>$/kWh</td>
<td>$0.1929</td>
</tr>
<tr>
<td>On-Peak</td>
<td>$/kWh</td>
<td>$0.1328</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>$/kWh</td>
<td>$0.1022</td>
</tr>
</tbody>
</table>
DEMAND CHARGES VS TOU RATES

• Demand charges a poor choice for small users due to high diversity
• TOU rates more accurately recover peaking costs across peak usage for all customers
• Baseload costs, and the distribution backbone are apportioned to all hours
BREAK FOR DISCUSSION
A BETTER SOLUTION: TOU RATES

From Costs to Rates

- Baseload Production
- Baseload Transmission
- Distribution Backbone
- Mid-Merit Production
- Network Transmission
- Peaking Production
- Distribution Peaking
- Demand Response
- Billing and Collection
SOLAR CUSTOMER UNDER TOU RATES

• If supplying valuable power, compensation to customer is higher
• If consuming valuable power, compensation to utility is higher
• With full net metering, utility often has a net cost
• With partial net-metering, customer often has a net cost
TWO VIEWS OF SOLAR VALUATION

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
ILLUSTRATIVE SOLAR CUSTOMER

Energy (kWh)

Retail Customer

Energy Efficiency

Solar Generation

Retail Customer

Power Export

Customer Load by Hour in 1 Day
## ILLUSTRATIVE TOU RATE DESIGN

<table>
<thead>
<tr>
<th>Period</th>
<th>Power</th>
<th>Delivery</th>
<th>Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Charge</td>
<td>$/month</td>
<td></td>
<td>$6.00</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>$/kWh</td>
<td>$ 0.04</td>
<td>$ 0.02</td>
</tr>
<tr>
<td>Shoulder</td>
<td>$/kWh</td>
<td>$ 0.08</td>
<td>$ 0.03</td>
</tr>
<tr>
<td>Peak</td>
<td>$/kWh</td>
<td>$ 0.10</td>
<td>$ 0.06</td>
</tr>
</tbody>
</table>
### EXAMPLE 1: ON-PEAK IS MID-DAY, OVERNIGHT IS LOW-COST; FULL NET METERING

<table>
<thead>
<tr>
<th>Period</th>
<th>Usage</th>
<th>Generation</th>
<th>Net</th>
<th>Price</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Charge</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$ 6.00</td>
</tr>
<tr>
<td>Overnight</td>
<td>300</td>
<td>0</td>
<td>300</td>
<td>$ 0.06</td>
<td>$ 18.00</td>
</tr>
<tr>
<td>Morning/Evening</td>
<td>500</td>
<td>200</td>
<td>300</td>
<td>$ 0.11</td>
<td>$ 33.00</td>
</tr>
<tr>
<td>Mid-Day</td>
<td>200</td>
<td>800</td>
<td>-600</td>
<td>$ 0.16</td>
<td>$(96.00)</td>
</tr>
<tr>
<td><strong>Total:</strong></td>
<td>1000</td>
<td>1000</td>
<td>0</td>
<td></td>
<td>$(39.00)</td>
</tr>
</tbody>
</table>
**EXAMPLE 2: SOLAR MID-DAY BULGE; ON-PEAK IS MORNING/EVENING, FULL NET METERING**

<table>
<thead>
<tr>
<th>Solar customer with mid-day bulge</th>
<th>Net Metering</th>
</tr>
</thead>
<tbody>
<tr>
<td>Period</td>
<td>Usage</td>
</tr>
<tr>
<td>Customer Charge</td>
<td></td>
</tr>
<tr>
<td>Overnight</td>
<td>300</td>
</tr>
<tr>
<td>Morning/Evening</td>
<td>500</td>
</tr>
<tr>
<td>Mid-Day</td>
<td>200</td>
</tr>
<tr>
<td>Total:</td>
<td>1000</td>
</tr>
</tbody>
</table>
### EXAMPLE 3: MID-DAY PEAK, PARTIAL NET METERING

<table>
<thead>
<tr>
<th>Solar customer with mid-day system peak</th>
<th>Partial Net Metering</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Period</strong></td>
<td><strong>Usage</strong></td>
</tr>
<tr>
<td>Customer Charge</td>
<td></td>
</tr>
<tr>
<td>Overnight</td>
<td>300</td>
</tr>
<tr>
<td>Morning/Evening</td>
<td>500</td>
</tr>
<tr>
<td>Mid-Day</td>
<td>200</td>
</tr>
<tr>
<td><strong>Total:</strong></td>
<td>1000</td>
</tr>
</tbody>
</table>
EXAMPLE 4: MORNING / EVENING PEAK, PARTIAL NET METERING

<table>
<thead>
<tr>
<th>Solar customer with evening system peak</th>
<th>Partial Net Metering</th>
</tr>
</thead>
<tbody>
<tr>
<td>Period</td>
<td>Usage</td>
</tr>
<tr>
<td>Customer Charge</td>
<td></td>
</tr>
<tr>
<td>Overnight</td>
<td>300</td>
</tr>
<tr>
<td>Morning/Evening</td>
<td>500</td>
</tr>
<tr>
<td>Mid-Day</td>
<td>200</td>
</tr>
<tr>
<td>Total:</td>
<td>1000</td>
</tr>
</tbody>
</table>
### Solar customer Buy-All / Sell-All

<table>
<thead>
<tr>
<th>Period</th>
<th>kWh</th>
<th>Price</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Charge</td>
<td></td>
<td>$6.00</td>
<td>$6.00</td>
</tr>
<tr>
<td>Overnight</td>
<td>300</td>
<td>$0.06</td>
<td>$18.00</td>
</tr>
<tr>
<td>Morning/Evening</td>
<td>500</td>
<td>$0.11</td>
<td>$55.00</td>
</tr>
<tr>
<td>Mid-Day</td>
<td>200</td>
<td>$0.16</td>
<td>$32.00</td>
</tr>
<tr>
<td>Generation</td>
<td>1000</td>
<td>$(0.10)</td>
<td>$(100.00)</td>
</tr>
<tr>
<td><strong>Total:</strong></td>
<td></td>
<td></td>
<td><strong>$11.00</strong></td>
</tr>
</tbody>
</table>
CALIFORNIA PUC NEM DECISION (2016)

- Customers can offset retail purchases with on-site generation without limit.
- Backfeed credited at full retail rate
- All power received from utility subject to several minor charges, totally $.025/kWh.
NEW HAMPSHIRE: A FRESH APPROACH

• Issued June 23
• Reaffirmed customer right to use output to offset retail purchases.
• Full net metering less two adjustments:
  – Only 25% distribution credit on backfeed
  – Stranded asset charges, System Benefit Charge and Taxes applied to all power flowing to the customer from the utility, but not credited on backfeed.
NEVADA: GRADUAL PHASE DOWN WITH GRANDFATHERING
BREAK FOR DISCUSSION
DISCUSSION QUESTIONS

• Does your utility assess or is it considering a mandatory demand charge for residential customers? What is/was the impetus? All customers, or just solar customers?
• What about TOU energy rates? Are they (or would they be) optional or mandatory for each customer class?
• Do you think all of your electric utility’s demand-related costs should be recovered in demand charges?
• How well do you think peaks on your distribution system coincide with your bulk system (generation & transmission) peaks?
• What concerns or questions do you have about residential demand charges or TOU rates?
HOW THE SOLAR CUSTOMER SEES IT
A HOME-GROWN TOMATO IS A “BETTER” TOMATO
LOTS OF PEOPLE
GROW THEIR OWN TOMATOES
WHAT IF YOU DON’T HAVE ENOUGH?
BUT, WHAT THE SOLAR CUSTOMER MAY FORGET...
WHAT IF YOU HAVE TOO MANY?
ALL TOMATOES ARE NOT EQUAL

Local Organic Tomatoes: $3.00/lb.
California Tomatoes: $2.00/lb.

We Buy Local Organic Tomatoes: $2.00/lb.
ALL KILOWATT-HOURS NOT EQUAL
TWO VIEWS OF SOLAR VALUATION

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
SUMMARY

• What is the role of price regulation?
• Solar resources have a value that is different from other resources.
• Should a solar customer be treated differently from an efficient customer?
• Can TOU pricing address concerns?
• Can TOU partial net-metering address concerns?
THE SOLAR MARKET PATHWAYS PROJECT IS SUPPORTED BY:

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AWARDEES OF

solarmarket
PATHWAYS

- Center for Sustainable Energy, California
- Virginia Private Colleges
- Pace Energy and Climate Center, Pace Law School
- extensible ENERGY
- Dominion
- The City University of New York
- mrea: midwest renewable energy association
- ecolibrium3: local energy matters
- SEPA: solar electric power association
- Institute for Sustainable Communities
- Vermont Energy Investment Corporation
- THE SOLAR FOUNDATION: Research and Education to Advance Solar Energy