Distributed Energy
Charges for Connecting to the Network

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Types of Generation to Address

- Net Metering
- Self Generation
- Distributed Generation
- Qualifying Facilities

Net Metering

- Federal Law (16 U.S.C. 2621(d))

  – Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves…

Net Metering

- When customer's generator is producing more power than being used, the electric meter runs backward generating credits. When the customer uses more power than is generated, the meter runs normally.
  - For customers with smaller generators (often household customers)
  - Customer may be required to pay for installation of a net meter – a meter that can measure the flow of electricity in both directions
  - Excess generation at the end of a year is generally paid to the customer at the avoided cost rate

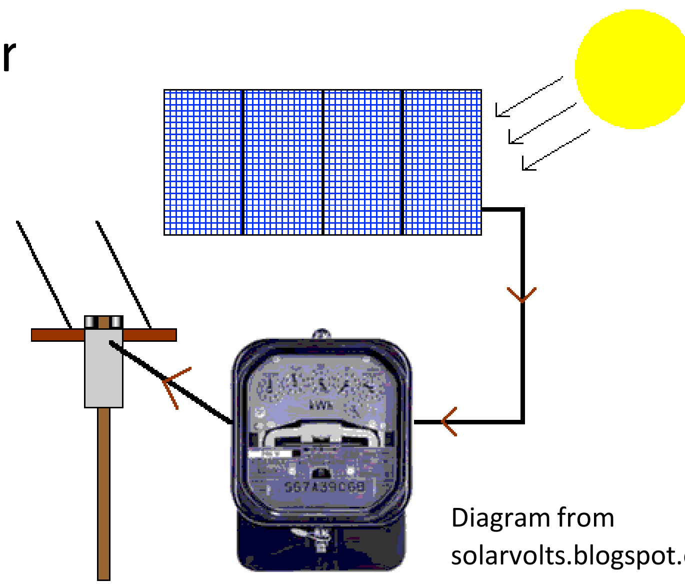

Diagram from solarvolts.blogspot.com

New York – Solar, Farm Waste and Wind Net Metering Rules
As of December 28, 2010

Eligible Renewable/Other Technologies:	Solar (PSL 66-j)		Farm Waste (PSL 66-j)	Micro CHP/Fuel Cells (PSL 66-j)	Wind (PSL 66-l)	
Applicable Sectors:	Residential	Non-Demand-/Demand Commercial	Farm-Based Residential / Non-Residential Farms	Residential Up to 10 kW	Residential / Farm-Based	Non-Demand/Demand Commercial
Limit on System Size:	25 kW Residential	Up to 2,000 kW (2 MW)	1000 kW (1 MW)		25 kW Residential/ 500 kW Farm Based	Up to 2,000 kW (2 MW)
Limit on Overall Enrollment [1]	1.0% of 2005 Demand per IOU (65,360 kW for NMPC)				0.3% of 2005 Demand per IOU (19,608 kW for NMPC)	
Treatment of Net Excess:	Residential - net excess will roll over monthly. At the end of 12 month period, any excess will be converted to a cash value and paid to the customer at SC6 avoided cost rates. Non-Demand Commercial customer's net excess will roll over monthly on an ongoing basis. Demand Commercial customer's excess is converted to its equivalent value and applied as a direct credit to the customer's current utility bill for outstanding energy, customer, demand and other charges on an ongoing basis. [2]		Residential/Non-Demand – net excess will roll over monthly. Demand customer's excess is converted to its equivalent value and applied as a direct credit to the customer's next utility bill for outstanding energy, customer, demand and other charges. For both demand and non-demand customers, at the end of the net metering year, any excess will be converted to a cash value and paid to the customer at SC6 avoided cost rates.	Net excess will be converted to a cash value calculated at SC6 avoided cost rates and applied as a direct credit to the customer's next bill for service. This dollar credit will be applied on the bill as a separate line item.	Residential/Farm-based – net excess will roll over monthly. At the end of 12 month period, any excess will be converted to a cash value and paid to the customer at SC6 avoided cost rates. Non-Demand Commercial customer's net excess will roll over monthly on an ongoing basis. Demand Commercial customer's excess is converted to its equivalent value and applied as a direct credit to the customer's current utility bill for outstanding energy, customer, demand and other charges on an ongoing basis. [2]	

(1) Net Metering is available on a "first come, first serve" basis determined by the date the utility notifies the DG Customer that it has received a complete project application.

(2) Demand customers will be subject to applicable actual metered demand charges consumed in that billing period. The Company will not adjust the demand charge to reflect demand ratchets or monthly demand minimums that might be applied to a standard tariff for net metering.

Stand By Rates (Partial Requirements)

- Applies to large customers with their own generation
  - Not apply if the customer's self generation is only in times of emergency, such as when utility's power is unavailable
- Service from utility provider is necessary when
  - Customer's equipment is being repaired or is out of service
  - More power is needed than the customer's equipment can provide (supplemental power)

Stand By Rates (Partial Requirements)

- U.S. Environmental Protection Agency Report (2009)
  - Developed by Combined Heat and Power Partnership
    - ***Model Tariffs for Stand By Rates (Generator's View)***
      1. Give customers a strong incentive to use electric service most efficiently
      2. Minimize the costs they impose on the system
      3. Avoid charges when service is not taken
      4. Contract Demand or Reservation Charges should be small compared to the peak demand and energy charges
      5. No more than *monthly* as-used demand charges (not ratcheted)
      6. Daily as-used demand charges (or even better, energy based charges to collect capacity costs)
      7. Rate structure yields a significant retail rate savings for kWh produced on site compared to kWh purchased from the grid

Stand By Rates (Partial Requirements)

- ***Ratemaking Principles Relevant to Rates for Standby Services***
  - Critical to determine the characteristics of the stand-by service
    - Which cause the utility to incur which specific costs?
    - Which cause the utility to avoid specific costs?
  - To what extent should the potential societal benefits of distributed generation be considered?

From Presentation by Rick Hornby, Synapse Energy Economics, as part of the NRRI Webinar on Stand-by Rates

Stand By Rates (Partial Requirements)

- *Example: Rocky Mountain Power (Wyoming)*
  - Requires a Contract
  - Tariff Rate Provisions
    - Basic Customer Charge (monthly amount)
    - Supplementary Demand Charge (per kW for amount contracted)[1]
    - Back Up Facilities Charge (per kW charge for amount contracted)
    - Back Up Demand Charge (per kW per day)[2]
      - Based on the 15 minute period of greatest use of Back Up Demand during the on-peak period

1 Some (such as ConEd of New York) have shared that this recovers the local distribution system costs.

2 ConEd also explains that this charge recovers the shared system (upstream) costs.

Stand By Rates (Partial Requirements)

- *Example: Rocky Mountain Power (Wyoming)*
  - Tariff Rate Provisions (Continued)
    - Maintenance Demand
      - Maintenance may only be scheduled for a maximum of 30 days per year
        - » One 30 day period or two 15 day periods
      - If prescheduled for scheduled maintenance, then only charged ½ of Back Up Demand Charge
        - » Excess of Scheduled amount is billed at the full Back Up demand charge
    - Excess Demand (per KW)
    - Supplemental and Back Up Energy (per kWh)
    - Excess Kvar or Reactive Power Charge

Stand By Rates (Partial Requirements)

- *Selected Provisions from Florida Power & Light Stand By Tariff*
  - Required if the Customer’s total generation capacity is more than 20% of the Customer’s total electrical load
  - Customer is required to give five years written notice before it can transfer to a retail rate service
    - Less than five years notice may be allowed if it can be shown that such transfer is in the *best interests of the Customer, the Company, and the Company’s other ratepayers*

Distributed Generation Interconnection Costs

Pacific Gas & Electric Company (California)

Generating Facility Type	Interconnection Request Fee	Supplemental Review Fee	Detailed Study Deposit	Additional Commissioning Test Verification
Non-Net Energy Metering	$800	$2,500	≤ 5MW = $10,000 (system impact study) + $25.000 (facilities study) >5 MW, $50,000 +1,000 per MW (up to a maximum of $250,000)	$150 /Person Hour*
Net Energy Metering	$0	$0	$0	N/A
Solar ≤1MW	First $5,000 of study fees waiver			

* Plus additional costs for travel, lodging and meals

Distributed Generation Interconnection Costs

- *Ameren (Illinois)*
  - Application Fee
    - < 10 kVa = $50
    - 10 to 10,000 kVA
      - Nameplate capacity is ≤ 2 MVA = $100 + $1 per kVA
      - Nameplate capacity is ≤ 50 kVA if connecting to area network = $500 + $2 per kVA
      - Nameplate capacity is ≤ 10 MVA if connecting to a radial distribution feeder = $500 + $2 per kVA
      - Nameplate capacity is ≤ 10 MVA and does not qualify for other categories above = $1,000 plus $2per kVA
    - >10,000 kVA
      - $15,000 Fee ($5,000 non-refundable; $10,000 applies to study costs)
  - Study Costs
  - Costs to Physically Connect to the Distribution System

Distributed Generation Interconnection Costs

- *National Grid (New York)*
  - Distributed Generation Projects >200kW and ≤2 MW where no electric power system upgrades are expected
  - Typical Activities involving Interconnection Costs
    - Engineering acceptance review of construction design particularly when involves service connection facilities, meter mounting, protective devices
    - Revenue metering equipment changes or additions
    - Field Audit of installation to accept design
    - Field compliance verification – witness tests of protective devices
    - Project Management

Distributed Generation Interconnection Costs

National Grid – New York

Complex DG Projects >200kW and ≤ 2MW:

Item No.	Typical Company Support Activities Attributed to DG Customer's Project	Common PSC No. 220 Tariff Rule References
1	Distribution EPS upgrades (e.g. Current Limiting Fuses, Primary Conductors, Line Reclosers, Switches, Voltage Regulators, Capacitors, etc.) as a result of DG impact.	15-18, 28, 36, 37, 53
2	Where Local EPS anti-islanding protection is required, DTT transmit addition to Distribution EPS substation feeder breaker (and/or Line Recloser) for DG impact on distribution feeder.	28, 36, 37, 53
3	Where Company-provided Radio Communications can be applied, additions to support DTT equipment at Distribution EPS substation feeder breaker (and/or Line Recloser) for DG impact on distribution feeder.	28, 36, 37, 53
4	Where Local EPS feeder selectivity may require prompt control measures for DG impact on distribution feeder operations, EMS-RTU (status & control) addition at Generation Facility.	28, 36, 37, 53
5	Service Connection modifications and additions for DG impact on Distribution EPS.	19-23, 28, 36, 37, 53
6	Revenue metering equipment changes/additions.	25, 28, 36, 37, 53
7	Engineering acceptance review of DG Customer's construction design submittals where the Company has mutual interest such as service connection facilities, meter mounting provisions, Company-designated protective devices and control schemes (e.g. DTT receive package installation at DG) according to the Company's ESB 750 series.	24, 28, 36, 37, 53
8	Field audit of DG Customer installation to accepted design.	24, 28, 36, 37, 53
9	Field compliance verification - witness tests of DG Customer protective devices coordinating with the Distribution EPS.	24, 28, 36, 37, 53
10	Project Management (DGS, Distr. Line, Distr. Station, etc.)	28, 53

Qualifying Facilities

- Small power production facility
  - Production is < 80 MW
  - Derives more than 50% of its energy input from biomass, wastes, renewable resources
  - < 25% of total energy derived is from oil, natural gas, and/or coal
  - May not be diesel powered
  - No more than 50% equity interest can be held by an electric utility or its affiliates

Qualifying Facilities

- A utility is obligated to purchase any energy and capacity which is made available from a qualifying facility
- Obligated Purchase Price Determination
  - Just and reasonable to the electric consumer
  - Not discriminate against cogeneration or small power production facilities
  - ***Utility not required to pay more than avoided costs***
  - Can be less than avoided cost if sufficient to encourage cogeneration and small power production
  - ***Standard Rates required for facilities with design capacity of ≤ 100 kW***
  - Standard Rates may be established with facilities with a design capacity of >100 kW

Qualifying Facilities

- Avoided Cost
  - Cost to an electric utility of *electric energy or capacity or both* which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source
  - ***Includes both Energy and Capacity***

Qualifying Facilities

- Factors impacting avoided costs
  1. Ability to dispatch
  2. Expected or demonstrated reliability
  3. Terms of contracts (duration of obligation, sanctions for non-compliance, etc.)
  4. Ability to coordinate scheduled outages of qualifying facility and the generation of the utility
  5. Usefulness of qualifying facilities energy and capacity during a system emergency
  6. Individual and aggregate value of energy and capacity from qualifying facilities on electric utility’s system
  7. Shorter lead times for capacity from qualifying facilities
  8. Costs or savings due to variations in line losses due to purchases from qualifying facility

Qualifying Facilities (Small)

- ***Rocky Mountain Power (Wyoming)***
- **Avoided Costs Tariff**
  - Applicable to smaller generators
    - Maximum 10 MW of average monthly capacity
  - Updated every two years
    - Based on power cost modeling
    - Starting point is the Integrated Resource Plan and its inputs and assumptions
  - Rates
    - See chart on next page for firm purchases
    - Non-firm purchases – Current rates per kWh – purchases from Qualifying Facilities before they achieve commercial operation
      - 2012 $0.0162 Winter $0.0186 Summer
      - 2013 $0.0191 Winter $0.0244 Summer
      - 2014 $0.0239 Winter $0.0287 Summer
      - 2015 $0.0256 Winter $0.0312 Summer

Qualifying Facilities (Small) -- Avoided Costs

Rocky Mountain Power (Wyoming)

	Previous Capacity ($/kW month)	Current Capacity ($/kW month)	Previous Winter Firm Energy ($ /kWh)	Current Winter Firm Energy ($ /kWh)	Previous Summer Firm Energy ($ /kWh)	Current Summer Firm Energy ($ /kWh)
2012	$2.08	N/A	$0.0187	N/A	$0.0300	N/A
2013	$2.12	$2.76	$0.0199	$0.0191	$0.0351	$0.0244
2014	$8.63	$2.82	$0.0588	$0.0239	$0.0588	$0.0287
2015	$8.79	$2.87	$0.0605	$0.0252	$0.0605	$0.0312
. . .						
2022	$9.94	$3.23	$0.0751	$0.0507	$0.0751	$0.0533
2023	$10.11	$3.29	$0.0720	$0.0535	$0.0720	$0.0570
2024	$10.29	$3.36	$0.0708	$0.0559	$0.0708	$0.0578
2025	$10.48	$13.68	$0.0742	$0.0447	$0.0742	$0.0447
2026	$10.66	$13.94	$0.0762	$0.0447	$0.0762	$0.0447

Tariff lists avoided cost rates for each year though 2036.

Qualifying Facility (Small) – Avoided Costs

- ***Rocky Mountain Power (Wyoming)***
  - **Short Run Avoided Costs – <u>Resource Sufficiency</u>** (2012-2024)
    - Based on displacement of purchased power and existing thermal resources *(production cost modeling)*
    - Two cost studies –
      - only difference is the assumption of a 50 aMW increase in resources, at zero running cost, which serves as a proxy for the qualifying facility generation
    - Avoided energy cost is highest variable cost incurred to serve total system load from existing and non-deferrable resources
    - Summer capacity costs are based on three-month capacity purchases
      - Equals ¼ of the capacity cost of a simple cycle combustion turbine

Qualifying Facility (Small) -- Avoided Cost

- ***Rocky Mountain Power (Wyoming)***
- **Long Run Avoided Costs – <u>Resource Deficiency</u>** (2025 -)
  – New resources required to provide both summer and winter capacity and energy
  – Avoided costs are the fixed and variable costs of a proxy resource that could be avoided or deferred (current proxy resource is a combined cycle combustion turbine)

Combined Cycle Turbine

Qualifying Facility (Small) -- Avoided Cost

- ***Rocky Mountain Power (Wyoming)***
- **Long Run Avoided Costs – <u>Resource Deficiency</u>** (2025 -) Continued
  – Split the fixed costs into capacity and energy components
    - Fixed cost related to capacity based on a simple cycle combustion turbine (which is usually acquired as a capacity resource)
      – *Assume all capacity costs are for on-peak load*
    - Fixed costs associated with construction of the combined cycle in excess of the simple cycle are assigned to energy
      – *Added to the variable production (fuel) cost of the combined cycle*
    - Fuel cost of the combined cycle is the avoided variable energy cost

Qualifying Facility (Small) -- Avoided Cost

- ***Rocky Mountain Power (Wyoming)***
- **Long Run Avoided Costs – <u>Resource Deficiency</u>** (2025 -) Continued
  - Avoided costs at 75%, 85%, and 95% capacity factors are modeled to illustrate the impact of differing generation levels
    - Primary avoided cost illustration based on 85% capacity factor
    - On peak capacity factor of the proxy resource is 88.2%

Qualifying Facilities (Large) – Avoided Cost

- ***Rocky Mountain Power (Wyoming)***
  - **No standard offer** but a procedure for calculating avoided costs is established
    - Potential Qualifying Facility may request an *indicative* pricing proposal – must provide general information including
      - *Generation technology*
      - *Design Capacity*
      - *Site Location*
      - *Interconnection Point*
      - *Proposed On-line Date*
      - *Outstanding Permit Requirements*
      - *Fuel Types and Sources*
      - *Plans for Fuel & Transport Agreements*
      - *Who pays Transmission Costs*
      - *Contract Term and Pricing Provisions*
      - *Status of Interconnection Arrangements*
      - *Quantity & timing of monthly power deliveries*
      - *Ability to be a Qualifying Facility*

Qualifying Facilities (Large) – Avoided Cost

- ***Rocky Mountain Power (Wyoming)***
  - **Avoided Cost Determining Procedure (continued)**
    - The indicative offer is provided within 30 days
      - Pricing is as if this project is first in the queue
      - Generator may use to make determinations about going forward with project
      - Prices not final until a signed agreement
    - Draft Power Purchase Agreement Prepared
      - Provided 45 days after updated and supplemental information provided by the generator
    - Generator comments on draft agreement & Negotiations begin
    - Power Purchases Prices not final until the agreement is signed
      - May be updated from earlier estimates if others have committed to build during the estimation process
    - Generator also required to enter into interconnection agreement

Qualifying Facilities (Large) – Avoided Cost

- ***Rocky Mountain Power (Wyoming)***
  - **Computation of Indicative Price**
    - *Differential Revenue Requirement (DRR)*
      - Long Term View so consider the generating resources to be added over the contractual time period – not just the currently existing generators
      - Measures savings by comparing
        - the revenue requirement pursuant to the utility's integrated resource plan and
        - The costs if add a new qualifying facility resource at zero cost
      - The savings are the present value of the reduced revenue requirement
      - Price paid to the qualifying facility is set equal to the savings

Qualifying Facilities (Large) – Avoided Cost

- ***Rocky Mountain Power (Wyoming)***
  - **Computation of Indicative Price**
    - *Partial Displacement Differential Revenue Requirement (PDDRR)*
      - Same as the DRR method (see prior page) but recognize capacity deferral
      - Calculate using two production cost modeling runs
        - One using the resources from the integrated resource plan
        - One with same resources except add in the new qualifying facility resource – which means that other planned resources should be deferred
      - Cost model does not have the logic to make resource deferrals
        - Instead, the next deferrable resource is decremented (partially displaced) by the size of the qualifying facility

Qualifying Facilities (Large) – Avoided Cost

- ***Rocky Mountain Power (Wyoming)***
  - **Computation of Indicative Price**
    - *Partial Displacement Differential Revenue Requirement (PDDRR)*
    - ***FOR A WIND QUALIFYING FACILITY***
      - Resources under 80 MW will use an integrated resource planning wind proxy as the resource being deferred

    - ***Qualifying Facilities also have the option to offer a bid in response to the utility's Request for Proposals for new generation. If bid is accepted, the bid price is used rather than the above calculation.***