MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

October 13, 2015

Mr. Charles E. Magraw
501 8th Ave.
Helena, MT 59601

Re: General Electric Rate Application
Docket No. D2015.6.51

Dear Mr. Magraw:

Enclosed please find Montana-Dakota Utilities Co.'s responses to The Alliance for Solar Choice's data requests dated September 29, 2015.

Sincerely,

Tamie A. Aberle

Tamie A. Aberle
Director of Regulatory Affairs

Attachments
cc: Service List

Montana-Dakota Utilities Co.
Docket No. D2015.6.51
Service List

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MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

TASC-001
RE: Customers with behind-the-meter generation

Please provide the number of customers in the Montana-Dakota Service Territory that have behind-the-meter generation in the following size categories, and for each identify of the type of generation (e.g. wind, solar, Combined-Heat-and-Power, fossil fuel generator).

1-5 kW
5-10 kW
10-15 kW
15-20 kW
20-25 kW
Greater than 25 Kw

Response:

Please see TASC-001 Attachment A.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA

NET METERING CUSTOMERS

MT

Account	City	Type	Size
MT-1	Miles City	Wind	1 KW
MT-2	Miles City	Wind	1 KW
MT-3	Forsyth	Wind	2.4 KW
MT-4	Wolf Point	Wind	2.4 KW

ND

Account	City	Type	Size
ND-1	Wishek	wind	2.6 KW
ND-2	Coulee	Solar	19.2 KW

SD

Account	City	Type	Size
SD-1	Herried	wind	2.6 KW

WY

Account	City	Type	Size
WY-1	Sheridan	Solar	4.43KW
WY-2	Sheridan	Solar	2.35KW
WY-3	Sheridan	solar	1.6KW
WY-4	Story	Wind	1.8KW
WY-5	Sheridan	Solar	2.76KW
WY-6	Sheridan	Solar	1.05KW
WY-7	Big Horn	Solar	1.4KW
WY-8	Big Horn	Solar	3.01KW
WY-9	Sheridan	Solar	5.06KW
WY-10	Dayton	Solar	15KW
WY-11	Sheridan	Solar	2KW
WY-12	Sheridan	Solar	1.44KW
WY-13	Sheridan	Solar	2.31KW
WY-14	Sheridan	Solar	5.28KW
WY-15	Big Horn	Solar	6.54KW
WY-16	Sheridan	Solar	1.6KW
WY-17	Big Horn	wind & Solar	2.4KW/2.28KW
WY-18	Big Horn	Solar	4.14KW
WY-19	Story	Solar	4.8KW
WY-20	Sheridan	Solar	2.15KW
WY-21	Acme	Solar	0.875KW
WY-22	Big Horn	Solar	3.64KW
WY-23	Sheridan	Solar	1.6KW
WY-24	Big Horn	Solar	0.86KW
WY-25	Big Horn	Solar	2.2KW
WY-26	Big Horn	Solar	3.66KW
WY-27	Big Horn	Solar	9.36KW
WY-28	Sheridan	Solar	6.15KW
WY-29	Sheridan	Solar	5.0KW

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-002
RE: Cost of Service Analysis Supporting Net Metering Rate 92 Tariff

Provide copies of all analyses, studies, memorandum or other documents showing how the proposed "tree-part residential rate" relates to costs of serving net metering customers or customers with behind the meter generation.

Response:

Please see Ms. Aberle's direct testimony at pages 7-9.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
DATA REQUEST
DATED SEPTEMBER 29, 2015
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TASC-003

RE: Cost of Service Analysis Supporting Net Metering Rate 92 demand charge

Provide copies of all analyses, studies, memorandum or other documents showing which costs MDU plans to recover in the proposed demand charge for net metering customers including all data supporting the cost of equipment or services involved. In your answer describe specifically which parts of the embedded class cost of service study and non-coincident demand of the residential class support the proposed demand charge.

Response:

Please see Response No. PSC-3.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-004
RE: Net Metering

Please provide all data, analyses, report, studies to support the conclusion in Ms. Aberle's testimony to the effect that net metering customers receive significant subsides at the expense of other utility customers.

Response:

The referenced subsidy was in regard to the carry forward credit available under the net metering tariff wherein net metering customers are effectively paid the retail rate for energy generated above their use and the standby generation, transmission and distribution investments necessary to serve distributed generation customers.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-005
RE: Net Metering

Has the MDU undertaken any study or analysis to assess the transmission, distribution, generation, environmental control costs that are avoided when a customer generates her own power behind-the-meter or when her system exports power from such generation on to the MDU distribution system?

Response:

No such studies exist.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-006
RE: Net Metering

Please provide all data, analyses, reports or studies to support the conclusion in Ms. Aberle's testimony to the effect that net metering creates "inequities" and describe what is meant by that term.

Response:

Please see Response No. TASC-004.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
DATA REQUEST
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TASC-007
RE: Demand Charge for Small General Service Customers

Describe what is meant by the following statement in Ms. Aberle's testimony: "The Small General Service customers served under Rate 20 or 26 will be charged the otherwise applicable demand charge as well." In your answer describe how this proposal differs from preexisting rates for Small General Service Customers served under Rate 20 or 26.

Response:

The proposal would not change the application of the demand charge component currently applicable under the Rates 20 and 26.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
DATA REQUEST
DATED SEPTEMBER 29, 2015
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TASC-008
RE: Demand Charge for Residential and Small General Service

Please describe the how the residential and small general service class peaks usage relate to the system peak and explain in detail how MDU used that data to allocate costs to that proposed Net Metering Rate 92 class, including identification of all cost data and cost allocators.

Response:

The residential class' coincidence factor is approximately 83 percent and the small firm general service class' coincidence factor is approximately 93 percent as shown in the load research data provided in Response No. LCG-009. Please see Response No. PSC-3 for the derivation of the proposed Rate 92 demand charge.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-009

RE: Demand Charge for Residential and Small General Service

Please (a) identify and provide a copy of all data showing the cost of providing customer-related services to residential customers with behind-the-meter generation, and the cost of customer service for residential customers without behind-the-meter generation. In your answer describe the differences for (i) metering, (ii) billing, (iii) customer account costs, and (iv) any other categories of distinct Residential distributed generation (DG) customer-related service.

Response:

Please see the embedded class cost of service study provided in Statement L and the marginal cost of services study provided in Exhibit No. (SJC-1) through Exhibit No. (SJC-11) representing the cost to service all residential customers. Studies were not prepared separately reflecting only behind the meter generation.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-010
RE: Demand Charge for Residential and Small General Service

State if MDU's cost allocation methods take into account the decrease in coincident demand and energy delivered for residences or small general service customers who have behind-the-meter solar generation. Provide the same answer for customers with behind -the-meter wind generation.

Response:

Montana-Dakota does not possess data supporting the premise that customers with behind-the-meter solar or wind generation result in a decrease in the coincident demand and energy delivered. The actual factor methods do not reflect adjustments to account for behind-the-meter generation beyond what is represented in actual data used to create the allocation factors.

**MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-011

RE: Demand Charge for Residential and Small General Service

Provide all data, reports, studies or other information in the possession of MDU which show how customers with on-site renewable generation contribute to system peak or circuit peaks in the MDU system, and in what amounts.

Response:

No such studies exist.

MONTANA-DAKOTA UTILITIES CO.
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TASC-012
RE: Demand Charge for Residential and Small General Service

Provide all projections in the possession of MDU which show how customers with future on-site renewable generation will contribute to system peak or circuit peaks in the MDU system, and in what amounts.

Response:

No such projections exist.

MONTANA-DAKOTA UTILITIES CO.
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TASC-013
RE: Demand Charge for Residential and Small General Service

Please (a) state if any customer-sited solar or wind distributed generation is included or taken into account in any way in the forecasted fuel and purchased power costs used to calculate MDU's system average base fuel cost for the Test Year Period and, (b) if so, explain how and state the amount and identify (by number and page) all MDU exhibits where that is explicitly shown or implicitly reflected, or (c) if not, explain why.

Response:

The fuel and purchased power costs reflect pro forma 2014 sales and therefore, historic use by the net metering customers is reflected in the calculation of the fuel and purchased power costs.

MONTANA-DAKOTA UTILITIES CO.
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TASC-014
RE: Demand Charge for Residential and Small General Service

Of the residential and Small General Service customers in MDU's service territory, please provide: (a) the number of those residential DG customers that have installed at least one energy efficiency measure under an MDU energy efficiency program; and, (b) the annual deemed energy savings attributable to the energy efficiency measures installed by those customers.

Response:

In 2014 five residential customers participated in Montana-Dakota's energy efficiency programs representing annual energy savings of approximately 2,270 Kwh.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-015

RE: Demand Charge for Residential and Small General Service

In regard to the previous question, state whether MDU is planning to impose a demand charge on these customers, and if not what is the rational for the proposal to impose a demand charge with on-site generation and not the customers who invest in on-site energy efficiency technology and show all cost of service studies or analyses that describe how the cost of service for these two types of customers differs.

Response:

Montana-Dakota is not proposing to implement a demand charge for all residential customers at this time. The demand charge is appropriate for the net metering customers because net metering does not necessarily result in reduced demand on the system, while customer conservation efforts through permanent changes like improved buildings and structures have the potential to reduce demand. While both may result in some short term losses because revenue under both situations is decreased, in the long term, upgrades that decrease the demand on the system will reduce costs. Those same benefits are not seen with net metering customers because they pay less for system fixed costs, but their overall demand does not necessarily decrease. Energy efficiency does not require the utility to be available with standby generation, transmission and distribution investments as with distributed generation customers.

MONTANA-DAKOTA UTILITIES CO.
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TASC-016
RE: Demand Charge for Residential and Small General Service

Provide any analysis in MDU's possession on the current or projected impact of customer-sited solar and wind DG on system losses, environmental control costs, generation costs (including fuel), distribution and transmission capital expenditures and explain how and provide all documents prepared and data obtained addressing that matter.

Response:

No such studies exist.

MONTANA-DAKOTA UTILITIES CO.
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TASC-017
RE: Demand Charge for Residential and Small General Service

Provide any studies analyses or projections in MDU's possession regarding the future expansion of behind-the-meter renewable generation by customers of MDU.

Response:

No such studies exist.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-018

RE: Demand Charge for Residential and Small General Service

State what percentage of MDU's residential customer of have meters capable of registering customer demand data, and explain what level of resolution (e.g. 5 minute, monthly) the data is collected, how often it is collected.

Response:

None of the residential customers in Montana are billed demand today and therefore demand billing meters are not in place. Approximately 94 percent of the customers in Montana are network AMR customers with the capability of producing 5 minute data on an hourly basis. Under the Company's proposal demand meters registering 15 minute data each month would be used for billing purposes.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-019

RE: Demand Charge for Residential and Small General Service

State what percentage of MDU's Small General Service customers have meters capable of registering customer demand data, and explain what level of resolution (e.g. 5 minute, monthly) the data is collected, how often it is collected.

Response:

29.6% of Small General customers in Montana have meters installed capable of registering demand for billing purposes. The data is collected based on 15 minute maximum use monthly.

MONTANA-DAKOTA UTILITIES CO.
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TASC-020
RE: Demand Charge for Residential and Small General Service

For customers who do not currently have meters capable of registering customer demand, if those customers were to install renewable energy generation behind-the-meter, how under the company's proposed demand tariff for such customers would the installation of such meters would be paid for and by whom.

Response:

Metering costs are a cost of service item and recovered through retail rates. The demand charge is proposed to be applicable to customers choosing the net metering option and therefore not automatically applicable to all customers that install renewable energy generation behind-the-meter.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-021
RE: Demand Charge for Residential and Small General Service

Please (a) state whether MDU has ever conducted or prepared any analysis of the reasonably determinable embedded costs and incremental costs to serve new customers with behind-the-meter renewable generation and the reasonably determinable benefits to its system provided by new interconnected customers for the Test Year period relied on by MDU in its Application or during the period after which MDU expects the rates proposed in its Application to become effective, (b) if so, explain why or (c) if not, explain why.

Response:

The marginal cost of service study provides the cost associated with connecting a new customer. The study was not separately prepared to represent behind-the-meter renewable generation.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-022

RE: Demand Charge for Residential and Small General Service

Explain why MDU believes that the imposition of a demand charge on customers with behind-the-meter generation is not a form of unlawful discrimination against such customers as is prohibited by the federal PURPA laws and regulations of the Federal Energy Regulatory Commission (FERC). Provide a copy of any analysis supporting the explanation that is in the possession of MDU

Response:

Montana-Dakota is not aware of federal PURPA laws and regulations addressing specific rate design under state regulated rates.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-023

RE: Demand Charge for Residential and Small General Service

Explain why MDU believes that the imposition of a demand charge on customers with behind the meter generation is not a form of unlawful discrimination against such customers as is prohibited the laws of the State of Montana and the rules of the Montana Public Service Commission. Provide a copy of any analysis that is in the possession of MDU supporting the explanation.

Response:

Montana-Dakota is not aware of any laws of the State of Montana or rules of the Montana Public Service Commission that address specific rate design methodologies.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-024
RE: Cost of Service Study

Please provide a copy MDU response to data requests from PSC, including but not limited to: 1) the cost of service study that was included in response to PSC 001-Data Response (CD format); 2) CD for electronic copy of Excel file Rate 92 Demand.

Response:

Copies of Montana-Dakota's response to PSC-001 through PSC-003 were shipped via Fedex to Charles Magraw on 8/11/2015 as well as David Wolley and the Alliance for Solar Choice consultant, Tom Power on 10/12/2015.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
DATA REQUEST
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TASC-025 RE: Cost of Service Study
Please quantify the increase in cost of transformers, service drops, and primary and secondary distribution lines for residential customers with electric space heating relative to residential customers without electric space and water heating. Provide supporting excerpts from design manuals, other engineering specifications, purchasing manuals, or other documentation.

Response:

No such studies exist.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
DATA REQUEST
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TASC-026

RE: Cost of Service Study

Please quantify the increase in cost of transformers, service drops, and primary and secondary distribution lines for residential customers with behind-the-meter renewable generation relative to residential customers without behind-the-meter renewable generation. Provide supporting excerpts from design manuals, other engineering specifications, purchasing manuals, or other documentation.

Response:

No such studies exist.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
DATA REQUEST
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TASC-027
RE: Cost of Service Study

Please provide all studies, analyses, workpapers, memoranda, or other documents prepared by MDU relating to the customer impacts of its proposed Rate 92 for residential and small commercial customers with behind-the-meter generation comparing current rates to those being proposed by MDU in this proceeding.

Response:

Please see Response No. PSC-005a.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
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TASC-028
RE: Cost of Service Study
Please provide any studies in MDU's possession regarding the prevalence and levels of demand charges applied to residential or small commercial customers with behind-the-meter renewable generation of electric utilities in the United States and Canada. Please identify any other studies on this topic of which MDU is aware but that are not in its possession.

Response:

Montana-Dakota has reviewed the two studies provided in Response No. TASC-028 Attachment A.

Response No. TASC-028
Attachment A

Key State Regulatory Activity on Net Energy Metering, Fixed Charges & Related Distributed Generation Issues

August 10, 2015

Recent Highlights

- **Arizona** – ALJ urges dismissal of APS DG fee reset in favor of 2016 rate case review
- **California** – Utility NEM successor proposals: demand charge, grid fees, lower export credits &/or TOU rates • Utility 'window' TOU proposals: SDG&E to try again in rate case following dismissal; PG&E settles
- **Hawaii** – HECO proposes community solar pilot
- **Illinois** – ICC dismisses petition for community solar/VNM for lack of legal authority
- **Iowa** – IPL seeks dismissal of Eagle Point complaint on 3rd party solar financing
- **Kansas** – Westar rate case: Settlement allows new resi DG rate class w/rate structure TBD in generic docket; resi customer charge increases; no resi demand charge rate options or community solar for now; TASC/EDF/others granted limited intervention incl. no participation in settlement
- **Maine** – PUC set to open inquiry on market-based solar policy design
- **Massachusetts** – Utilities to file 10-year grid modernization plans on Aug 19 per extension
- **Minnesota** – PUC adopts partial settlement on solar gardens, seeks comment re design change process; adopts final NEM rule changes
- **Missouri** – PSC adopts final RES/NEM rule changes
- **Montana** – TASC granted intervention in MDU rate case w/resi NEM demand charge proposal
- **New Hampshire** – Agreement in works on NEM queue mgt. • PUC opens grid modernization investigation
- **New Mexico** – TASC granted intervention over EPE opposition in rate case; TASC & Vote Solar seek dismissal of EPE separate rate class proposal • SPS appeals rate case rejection to state high court • PRC seeks stay/remand of PNM rate case appeal; opens NOI on future test year issues • PRC tables AG petition for investigation of DG impact
- **Nevada** – NVE proposes 3-part rates for new resi NEM • PUC set to act on TASC petition on NEM cap
- **New York** – PSC approves community DG program; utility role centered on billing obligations • Staff proposes REV rate/business model reform incl. potential transition to 3-part rates, NEM retention w/compensation reform, expanded TOU rate options • Staff issues proposal on DER supplier oversight • REV market design group issues draft report • Utility REV demo projects selected; CHG&E community solar w/utility ownership under separate review
- **Oregon** – PGE community solar tariff approved for contracted project; future projects w/possible utility ownership TBD case by case
- **Rhode Island** – NGrid proposes 4-tier resi customer charge akin to demand charge structure & fee for parasitic DG facilities
- **Texas** – Entergy withdraws rate case application
- **Virginia** – SCC approves Dominion community solar pilot w/utility-owned DG

State	Issue/Proceeding	Next Steps	Date (2015*)	Recent Key Activities
AR	Entergy rate case-increase resi customer charge from $6.96 to $9/mo. (Case 15-015-U)	Staff/intervenor testimony Entergy rebuttal testimony Staff/intervenor surrebuttal Entergy sur-surrebuttal Parties-issue list of settlement proposal Evidentiary hearing begins Public comment hearings Decision expected by	Sep 29 Oct 27 Nov 24 Dec 10 Dec 31 2016 Jan 19 Jan 26 & 28 Feb 24	Jul 8: PSC grants limited intervention to Sierra Club Jul 8 & 13: PSC conditions interventions by AR Advanced Energy Assn & solar developer on uniting w/Sierra Club as single participant Note: Entergy, staff, AG, other parties opposed all 3 petitions
AZ	APS-NEM cost shift solution-reset solar DG fee from $.70/kW to $3/kW (Case E-01345A-13-0248)	ACC tentative deliberation-ALJ recommendation	Aug 18-19	Jun 12: Oral argument-rate case issue Aug 3: ALJ urges dismissal of fee reset in favor of full consideration of cost/shift rate design issues in next rate case expected 2Q 2016
AZ	TEP-restructure NEM tariff to lower subsidy (Case E-01933A-15-0100)			Jun 19: Application withdrawn-TEP to file rate case by end of 2015 to address issues Jul 27: ALJ-dismiss application w/o prejudice
AZ	UNS Electric rate case: increase resi customer charge ($10 to $20/mo.), optional resi 3-part rate w/TOU version, mandatory DG 3-part rate w/TOU version, NEM tariff restructure (Case E-04204A-15-0142)	Motions to intervene Direct testimony-not rate design Direct testimony-rate design Rebuttal testimony Surrebuttal testimony Co. rejoinder testimony Prehearing conference Evidentiary hearings begin	Oct 15 Nov 6 Dec 9 2016 Jan 19 Feb 19 Feb 26 Feb 26 Mar 1	May 5: Application filed
AZ	Sulphur Springs Valley Elec Co-op-restructure NEM tariff (Case E-01575A-15-0127)	Oral argument	Aug 20	Apr 22: Staff seeks rate case consideration Jul 31: Initial briefs Aug 4: Response briefs
AZ	Trico Elec Co-op-restructure NEM tariff; reduce avoided cost (Case E-01461A-15-0057)			Jul 6: Trico withdrew NEM tariff restructure portion; will repropose in rate case by end of 2015, possibly Oct Jul 29: ALJ-approve partial withdrawal Jul 30: Staff-approve reduced avoided cost
AZ	ACC inquiry-solar DG business models/practices & impacts (Case E-00000J-14-0415)			Feb 13: Comments
AZ	ACC-generic rate design (Case AU-00000C-14-0329)			Oct 20, 2014: Comments
AZ	ACC-value & costs of DG to grid (Case E-00000J-14-0023)			Jul 14 & 21: ACC chair-SolarCity letters on consumer protections

AZ	ACC-emerging technologies incl. DG (Case E-00000J-13-0375)			Feb 26: Workshop-IRP Jul 9: Comm'er R. Burns letter seeking more utility information on 2016 EE/DSM plans Jul 31: Utility response-Burns
CA	Rulemaking-refine energy storage policies/procurement w/implications for DG integration (Case R15-03-011)	Track 1 Workshop Workshop reports Comments-workshop reports Proposed decision Track 2 Scoping/scheduling ruling Opening & reply comments Workshops Staff procedural & interagency coordination matrix Workshop reports Opening & reply comments-workshop reports Proposed decision Measurement & eval in record	 Aug 19 Late Sep Oct Dec Sep Oct Nov Jan 2016 Jan Feb 2 or 3Q 4Q	Mar 26: Rulemaking opened May 20: Prehearing conference Jun 12: Scoping memo/ruling-sets 2 tracks Jul 8: Opening comments Jul 23: Workshop Aug 3: Reply comments
CA	Rulemaking-regulatory framework for integrated DSM including DG (Case R14-10-003)	Any additional workshops Proposals for customer solutions demo; workshop-Phase 2 Workshop report Proposed decision-Phase 2	TBD TBD 30 days from Ph. 2 workshop 18 mos. from scoping memo	Mar 11-12: Workshop Apr 15: Ruling-workshop overview, request for comments on specified questions May 15: Comments May 29: Reply comments Jul 30: Workshop
CA	Rulemaking-distribution resource plans per AB 327 (Case R14-08-013 et al.-consolidated w/individual utility DRP applications)	Protests/responses to DPRs Reply comments Prehearing conference Decision	Aug 31 Sep 15 Sep 23 Mar 2016	Jul 1: Utilities file DRPs incl. proposed demo projects
CA	Successor NEM contract/tariff per AB 327 (Case R14-07-002)	Requests for evidentiary hearing Responses to hearing requests Comments-proposals & 2 staff papers Reply comments Proposed decision Statutory deadline for decision	Aug 10 (rev.) Aug 14 (rev.) Sep 1 (rev.) Sep 15 (rev.) 4Q Dec 31	Aug 3: Utility successor proposals-variously incl. demand charge, grid fees, lower energy export compensation &/or TOU energy rates for new NEM resi customers
CA	Certain DER issues related to storage issues, Self-Generation Incentive Program (SGIP), other (Case R12-11-005)			Jul 10: Proposed decision updating GHG factor for determining SGIP eligibility Jul 30: Comments Aug 3: Reply comments
CA	Rate design-comprehensive resi reform (Case R12-06-013, Phase 1)	Utilities file memorandum accounts, start process for working groups incl. TOU design Utilities file new rates & "glidepath" for new rate tiers, SUE surcharge implementation Utilities file outreach/education plans for SUE surcharge	W/in 30 days W/in 60 days Oct 16	Jul 13: Final decision issued-rejects utility-proposed fixed charges, requires $10 minimum bill for 2015 ($5-low income), resi TOU rates for 2019, super user electric (SUE) surcharge, annual rate reform summits;

		Utilities file default TOU rates Phase 3 Prehearing conference	Jan 1, 2018 Summer 2015	sets next steps for Phase 3 incl. low-income issues Jul 14: Florio concurrence
CA	Rulemaking on DG interconnection (Case R11-09-011)	Final action-proceeding ends	May 2016	Apr 1: PG&E, SCE & SDG&E jt. motions re behind the meter, non-exporting energy storage & cost certainty May-Jun: Comment process Aug 6: Status conference
CA	Shared solar-implementation of SB 43 & utility applications (Case A12-01-008, et al.)	Track A reply comments Track A workshop Track A proposed decision Track B opening comments Track B reply comments Track B workshop Track B proposed decision	Aug 28 Sep 28 Nov Nov 2 Dec 2 Jan 5, 2016 Mar 2016	Apr 15: Scoping memo for Phase IV creates Track A including rate design issues & Track B; schedule set Aug 7: Track A opening comments
CA	PG&E rate design window-changes in optional resi TOU rate (Case A14-11-014)	Reply briefs	Aug 11	11/25/14: Application filed Jun 29: Evidentiary hearing Jul 21: Opening briefs Jul 23: Settlement
CA	SDG&E rate design window-TOU changes (Case A14-01-027)			Jul 10: ALJ proposed decision-dismiss w/o prejudice proposals to modify peak periods; SDG&E will re-propose in rate design phase of general rate case; CALSEIA sought rate case consideration
CO	PUC generic proceeding on DG/NEM (Case 14M-0235E)			Apr 10: Xcel files solar DG cost/benefit study Apr 23: 4th panel discussion May 22: Post-panel comments Jun 5: Reply comments
CT	Investigation of electric submetering; Phase 2 issues incl. on-site generation (Case 13-01-26)			Jul 1: PURA final decision-retail rate is maximum submetering customers may charge submetered customers for renewable DG supply
DC	NEM rule changes (Case FC 945)-implement Community Renewable Energy Amendment Act (2013)			Apr 24: PSC final rules-community NEM; wholesale credit rate Jul 8: Comment Jul 23: Reply comment
FL	PSC input gathering for solar policy development, undocketed			Apr 23: PSC press release, staff memo requesting comments Jun 23: Comments
GA	GP market-based procurement-Advanced Solar Initiative-DG resources (Case 36325)			Jul 30: PSC approves final revised program guidelines & pro forma PPAs for 2015-16
GA	GSEIA, Vote Solar & IREC petition to establish VOS (Case 38619)			Oct 15: GSEIA petition for procedure to resolve issues Jan 22: GP seeks petition denial
HI	HECO community solar pilot (Case info not yet available)			Jul 15: HECO press release

HI	PUC investigation of DER policies & modification of DG interconnection tariff Rule 14H (Consolidated Cases 2014-0192 & 2014-0130)	PUC decision on Phase 1 & guidance for Phase 2	TBD	Jun 29: Parties final statements of position; HECO proposed DER market transition program incl. self- & grid-supply options w/lower bill credit, residential TOU pilot, & DER integration-related proposals Jun 29: Settlement-revisions to interconnection Rule 4H Jul 2: TASC motion for evidentiary hearings Jul 10: HECO opposes TASC motion, seeks removal of TASC from proceeding
HI	PUC review-utility power supply improvement plans (Case 2014-0183)			Aug. 26: Utilities file PSIPs Oct 6: Public comments
IA	Eagle Point Solar complaint alleging IPL seeks to block certain third party-financed solar projects (Case FCU-2015-0009)			Jun 26: Complaint filed w/IUB Jul 15: IPL motion to dismiss Jul 29: Solar/other groups seek intervention, oppose IPL motion Aug 6: IPL reply
IA	NOI on DG (Case NOI-2014-0001)			Apr 30: IUB seeks comment on proposed DG policy goal & specified policy options Jun 15: Comments Jul 15: Reply comments
ID	Avista rate case-increase resi customer charge from \$5.25 to \$8.50/mo. (Case AVU-E-15-05)	Expected decision	Dec 31	Jun 1: Application filed
IL	Ameren rate case-increase resi customer charge from \$10.57 to \$12/mo. (Case 15-0305)	Staff/intervenor rebuttal Co. surrebuttal Prehearing motions Status/motion hearing Evidentiary hearing Initial briefs Reply briefs Optional statements of position Proposed order Briefs on exception Decision deadline	Sep 3 Sep 15 Sep 16 Sep 17 Sep 21-22 Oct 6 Oct 16 Oct 16 Nov 10 (tent.) Nov 20 (tent.) Dec 20	Apr 24: Application filed May 28: Prehearing conference Jul 13: Staff/intervenor testimony Aug 7: Rebuttal
IL	Rulemaking-changes to NEM rule (Case 15-0273)			May 8: Proposed rules issued Jun 24: Comments Aug 4: Notice-hearing continued
IL	CUB/EDF petition-community solar w/VNM for ComEd (Case 15-0156)			Jul 28: ICC dismisses petition, cites lack of legal authority
IL	Revisions to DG interconnection rules per petition of CUB, ELPC (Case 14-0135)			Mar 4: ALJ proposed order seeks additional information May 20: Comments Jun 3: Reply comments
IN	IPL rate case w/resi customer charge increase-\$11 to \$17/mo.; investigation of IPL network	IPL rebuttal; other parties cross-answers Evidentiary hearing	Sep 4 Sep 21-Oct 2	Apr 15: Procedural order following case consolidation

	facilities (Consolidated Cases 44576 & 44602)	Decision expected by	Oct 23	Jul 27: Staff/intervenor testimony
KS	Westar rate case w/rate design changes; 2 new resi rate options incl. demand charge; higher customer charges (Case 15-WSEE-115-RTS)	Comment-settlement; end of public comment period List of contested issues Prehearing conference Evidentiary hearing Initial company brief Staff/intervenor initial briefs Reply briefs Decision	Aug 11 Aug 11 Aug 12 Aug 17-21 Sep 11 Sep 22 Sep 29 Oct 28	Jul 23: KCC-limited intervention to TASC, EDF, others; precludes settlement participation Aug 6: Settlement-new standard resi DG tariff w/rate structure left to generic docket; higher resi customer charge; resi rate options w/demand charge & community solar set aside
KS	KCP&L rate case w/resi customer charge increase-$10.71 to $19/mo. (Case 15-KCPE-116-RTS)	Decision expected by	Sep 10	Jun 17: Non-unanimous settlement-$14 resi cust. charge Jun 4-15: Evidentiary hearing Jul: Briefs
KY	KU rate case w/resi customer charge increase-$10.75 to $18/mo.; NEM clarifying changes (Case 2014-00371)			Jun 30: PSC approves settlement w/no increase in resi customer charge; allows optional resi time of day rate w/demand charge
KY	LGE rate case w/resi customer charge increase-$10.75 to $18/mo.; NEM clarifying changes (Case 2014-00371)			Jun 30: PSC approves settlement w/no increase in resi customer charge; allows optional resi time of day rate w/demand charge
KY	KP rate case w/resi customer charge increase-$8 to $16/mo. (Case 2014-00396)			Jun 22: PSC approves settlement but lowers customer charge from agreed level
LA	PSC study of NEM costs/benefits (Case X-33192)			Feb 27: PSC draft solar NEM report finds greater costs than benefits, growing subsidy by lower-income ratepayers Mar 24: Interventions & comment on draft report
LA	Consolidated co-op proceeding-staff calculation of NEM cap (Case U-32913, R-31417, et al.)			Mar 17: ALJ final recommendation
MA	DPU stakeholder conference on energy storage (Case 15-ESC-1)	Consultant-led stakeholder engagement Final presentation of findings Study reports	Aug-Nov Dec/Jan 2016 Jan	May 28: Governor energy storage initiative feat. DOER/MassCEC-led study Jun 9: Stakeholder conference
MA	DPU rulemaking on NEM for small hydro (Case 14-118)			Jun 30: DPU report & draft legislation to legislature-supports NEM for small hydro
MA	DPU investigation-grid modernization (Case 12-76)	Utilities file 10-yr grid mod plans	Aug 19 (rev.)	Aug 4: Extension granted from Aug 5 for utility grid mod plans
MA	Investigation into DG interconnection (Case 11-75, et al.)			May 4: DPU-final revised model tariff jointly filed by utilities May 13: Utility revised tariffs May 22: Comments-rev. tariffs
MD	Exelon-PHI merger incl. settlement w/TASC re interconnection			May 15: PSC conditionally approves merger & TASC settlement, which is modified to

	enhancements to promote on-site solar/battery energy (Case 9361)			prohibit discrimination in favor of renewable technology
ME	Inquiry-market-based solar policy design stakeholder process (Case 2015-00218)	PUC deliberates initiating inquiry	Aug 11	
MI	Consumers Energy community solar pilot; bill credits based on VOS (Case U-17752)	Staff report-VOS methodology	Sep 30	May 14: PSC conditionally approves; Solar Working Group (SWG) to reconvene to look at VOS inputs; staff to make recommendations Jun 9: SWG kickoff
MI	Consumers Energy cost allocation & rate design changes per Public Act 169 (Case U-17688)			Jun 30: PSC order directing optional TOU rates for AMI customers; effects of all approved changes are resi rate increases, decreases for others
MI	DTE Electric cost allocation & rate design changes per Public Act 169 (Case U-17689)			Jun 15: PSC order directing optional TOU rates for AMI customers; effects of all approved changes are resi rate increases, decreases for others
MI	DTE rate case w/resi customer charge increase-$6 to $10/mo. (Case U-17767)	Reply briefs Proposed final decision Exceptions Replies to exceptions Decision expected by	Aug 12 Oct 8 Oct 27 Nov 19 Dec 19	Jun 15: Rebuttal testimony Jun 17: Motions to strike Jun 23-30; Jul 6: Hearing Jul 28: Briefs
MN	PUC inquiry on standby service tariffs (Case E-999/CI-15-115)			Jan 30: DOC files report Feb 12: PUC notice of comment Apr 15: Initial comments May 15: Reply comments
MN	Xcel Energy solar garden (Case 13-867)	Comments-Jul 24 request Reply comments	Aug 31 Sep 14	Jul 24: Xcel/other parties seek investigation of prospective program design changes Aug 6: Written PUC order approving partial settlement
MN	NEM rule changes (Case 13-729)			Jun 12: PUC vote-adopts proposed rules w/modifications Jul 17: PUC final order-notice pending publication in register
MN	e21 initiative incl. grid modernization, DER integration (Case 14-1055)			Dec 22: Xcel files request for planning meeting & dialogue Feb 26: PUC planning meeting
MO	Ameren MO rate case-solar rebate costs, resi customer charge increase from $8 to $8.7/mo. (Case ER-2014-0258)			Apr 29: PSC rejects resi customer charge increase, allows amortized full recovery of $92m of solar rebate costs opposed by customer groups
MO	EDE rate case w/resi customer charge increase-$12.52 to $18.75/mo. (Case ER-2014-0351)			Jun 24: PSC adopts settlement w/no increase in resi customer charge & certain commitments re standby service

MO	KCP&L rate case w/resi customer charge increase-$9 to $25/mo. (Case ER-2014-0370)	Decision expected by	Aug 31	Jun 16: Non-unanimous rate design settlement-unchanged resi customer charge, higher resi energy charges, other Jun 15-Jul 2: Evidentiary hearing Jun 22: KCP&L filed objection to non-unanimous settlement & request for hearing Jul: True-up steps
MO	PSC proposed changes to NEM & RES rules (Case EX-2014-0352)			May 1: Proposed rules published in MO Register Aug 5: PSC approved final rules; to be sent to secy. of state
MS	Proposed NEM & interconnection rules (Case 2011-AD-002)	Public hearing	TBD	Apr 7: PSC issues proposed rules for comment Jul 1: Comments
MT	MDU rate case w/rate design changes: increase customer charge from $5.40 to $7.60/mo.; add resi NEM demand charge of $1.50/kW/mo. (Case D2015.6.51)	Expected decision	Mar 31, 2016	Jun 25: Application filed Aug 6: TASC, 2 other parties granted intervention
NC	NC WARN request for declaratory ruling on 3rd party sales (Case SP-100, Sub 31)			Jun 17: Request filed-NC WARN via PPA to install solar PV on church roof & sell energy to church in 'test case'
NC	Revisions to small generator interconnection standards (Case E-100, Sub 101)			May 15: UC approved revised interconnection standard May 18: UC approved revised interconnection agreement
NC	2014 biennial avoided cost proceeding including VOS issue (Case E-100, Sub 140)	Reply comments Parties' proposed orders	Aug 17 (rev.) Sep 4 (rev.)	Dec 31: UC sets avoided cost input parameters Mar 2: Utilities file proposed avoided cost rates Jun 22: Comments
NH	Investigation-grid modernization per HB 614 (2015) (Case IR 15-296)	Comment Technical session	Sep 17 TBD	Jul 30: PUC notice opening docket
NH	Review of interconnection & queue mgt. processes-response to growth in group NEM (Case DE 15-271)	Technical sessions	Aug 6 & 12	Aug 3: Staff reports progress toward agreement; numerous interventions granted incl. utilities, TASC
NJ	Update of 2011 NJ Energy Master Plan, undocketed	Hearings Comment	Aug 11, 13, 17 Aug 24	Jul 11: BPU notice
NJ	Updates to renewable energy rules-technical working group on NEM/interconnection (undocketed)			Apr 20: NEM/interconnection working group meeting
NJ	Aggregated net metering (Case EO12090832V, et al.)			Apr 20: Final rule published in NJ Register readopting earlier temporary rules
NM	SPS rate case-increase resi customer charge from $7.90 to $9.50/mo. (Case 15-00139-UT)			Jun 24: PRC rejects filing, cites error in future test year start; SPS may refile application Jun 29: Comm'er Jones dissents

				Jul 9: SPS appeals to NM Supreme Court (Case 35,406)
NM	EPE rate case-create DG rate class, increase resi customer charge from $7 to $10/mo. (Case 15-00127-UT)	Staff/intervenor testimony or settlement Statements opposing settlement Testimony supporting settlement Testimony opposing settlement Rebuttal testimony Response testimony-settlement Hearing Expected decision	Sep 30 Oct 5 Oct 16 Oct 23 Oct 28 Oct 30 Nov 16 Mar 15, 2016	Aug 3-7: TASC granted intervention over EPE opposition; TASC & Vote Solar move to dismiss proposal for separate rate class
NM	PNM rate case w/resi customer charge increase-$5 to $12.80; new DG interconnection fee-$6/kW/mo. for new resi customers (Case 14-00332-UT)			May 13: PRC dismisses application as incomplete Jun 25: PNM appeals to NM Supreme Court (Case 35,377) Jul 15 PRC moved for stay & remand; opened NOI on future test year parameters in rate cases (Docket No. 15-00216-UT)
NM	AG petition-investigation of DG impact on utility systems (Case 15-00090-UT)			Jul 22: PRC votes to table; order not yet posted
NV	NVE-COS studies & NEM tariffs per SB 374 (2015) incl. choice of 2 new 3-part rates (with & w/o TOU) for new resi NEM customers (Cases 15-07041 (NP), 15-07042 (SPP)	Interventions/comments Prehearing conference Hearing	Aug 17 Aug 19 Aug 21	Jul 31: Applications filed
NV	TASC petition for declaratory order re NEM, per SB 374 (2015) (Case 15-07021)	PUC deliberation	Aug 12	Jul 8: Emergency petition filed Aug 5: Comments
NV	PUC investigation/rulemaking-possible changes to solar incentive program (Case 15-06054)	Reply comments Workshop	Aug 21 Aug 25	Jul 1: PUC opens docket Aug 7: Comments
NV	PUC investigation of separate rate classes for NEM customers (Case 14-06009)			Jul 31: NVE filings-COS studies & NEM/rate design changes (new case entry above)
NY	NYSEG rate case-increase resi customer charge from $21.38 to $26.73/mo. (Case 15-E-0283); potential resi demand charge for proposed REV project	Staff/intervenor testimony Rebuttal testimony Evidentiary hearings begin Post-hearing schedule Decision expected by	Sep 16 Oct 13 Nov 4 (rev.) TBD Apr 20, 2016	May 20: Application filed Jun 22: Procedural/technical conference
NY	RG&E rate case-increase resi customer charge from $15.11 to $18.89/mo. (Case 15-E-0285); potential resi demand charge for proposed REV project	Staff/intervenor testimony Rebuttal testimony Evidentiary hearings begin Post-hearing schedule Decision expected by	Sep 16 Oct 13 Nov 4 (rev.) TBD Apr 20, 2016	May 20: Application filed Jun 22: Procedural/technical conference
NY	ConEd rate case incl. higher resi customer charge-from $15.76 to $18/mo. (Case 15-E-0050) Note: Settlement filed in previous rate case docket, No. 13-E-0030-See last column			Jun 17: PSC decision-adopts settlement extending current rate plan thru 12/31/16 in lieu of proposed changes; resi customer charge unchanged; certain changes made to

				standby tariff subject to requirements in REV proceeding
NY	ConEd-REV projects/programs incl. cost recovery mechanism (Case 15-00844)			Apr 13: Petition filed
NY	O&R rate case incl. higher resi customer charge-from $20 to $25/mo.; REV surcharge; community solar (Case 14-E-0493)	Decision expected by	Oct 31	Jun 5: Settlement-no change in resi customer charge; new REV surcharge mechanism; collaborative process for REV demo projects incl. comm solar Jun-Jul: Comment process Aug 4: Evidentiary hearing
NY	CHG&E rate case incl. higher resi customer charge-from $24 to $30/mo.; community solar (Case 14-E-0318)			Jun 17: PSC rejects resi customer charge increase, approves NWA project to reduce load via DER; other demo projects incl. community solar to proceed in REV case
NY	Large-scale renewables program (REV track), Case 15-E-0302	Initial comments Reply comments Technical conference	Aug 12 (rev.) Sep 14 (rev.) TBD	Jun 1: Docket opened; NYSERDA/staff paper filed Jul 8: Technical conference
NY	Ease restrictions under existing remote NEM tariffs, Case 15-E-0267			May 11: PSC opens proceeding Jun 29: Comments Jul 13: Reply comments
NY	Regulation of DER providers & products (Case 15-M-0180)	Technical conference Comments Reply comments	Aug 20 Sep 25 Oct 19	Jul 28: Staff proposal incl. uniform business practices, recommendation for code of conduct rules
NY	Generic-develop community net metering (Case 15-E-0082)	Utilities file maps of DG zones Utilities file community DG tariffs Staff initiates low-income collaborative Staff initiates process for DER valuation Staff reports on low-income issues & DER valuation	W/in 45 days W/in 60 days W/in 60 days W/in 60 days Jan 15, 2016	Jul 17: PSC-approves community DG program based on NEM paradigm; utility role centered on billing obligations
NY	Continuation of standby rate exemption for CHP/certain DG (Case 14-E-0488)			Apr 20: PSC extends 5/31/15 expiration to 5/31/19, raises 1 MW cap on CHP to 15 MW May 20: Utilities seek rehearing on cap increase Aug 3: Comment
NY	Generic-enable community choice aggregation (Case 14-M-0224)			Dec 15: PSC opens docket as part of effort to promote renewables/DER; staff white paper poses questions Feb 17: Comments
NY	Reforming the Energy Vision (REV) initiative. Track 1 = role of utility as distribution system platform provider. Track 2 = regulatory & ratemaking changes (Case 14-M-0101)	Track 1: Comments-staff BCA paper Staff reports to PSC-DG emission rules & billing initiatives Staff guidance-DSIPs Reply comments-staff BCA paper	 Aug 21 (rev.) Sep 1 Sep 8 (rev.) Sep 10	Feb 26: PSC-policy framework & implementation plan Jul 1: Staff benefit-cost analysis (BCA) white paper; utilities propose demo projects (Track 1); per staff, CHG&E separately

		Utilities file DSIPs Staff-energy efficiency best practices guide Track 2: Comments-staff straw proposal Reply comments	Jan 15, 2016 Feb 1, 2016 Oct 5 Nov 2	proposes community solar project w/utility ownership Jul 15: MDPT group-draft report Jul 28: Staff Track 2 straw proposal-ratemaking & utility business model reforms; incl. transition to 3-part rates, retention of NEM w/compensation reform, DER valuation, more TOU options Aug 4: Announcement-approved utility demo projects
NY	Petitions on process for utilities reaching NEM caps (Cases 14-E-0422, 14-E-0151) & to raise CHG&E NEM cap (above dockets & Case 03-E-0188)			Jul 13: O&R notifies PSC of cap exceedance, seeks approval of buy-all, sell-all arrangement above cap; alternatively asks to work w/staff on sustainable NEM solution
OH	Rulemaking-5 yr. review of utility rules including NEM (Case 12-2050-EL-ORD)			Jul 18: OH Edison appeals to OH Sup Ct (Case 2014-1290) Nov 14: PUC withdraws rule May 5: PUC workshop
OH	Rulemaking on RPS costs per SB 310 (Case 14-1411-EL-ORD)			Jul 1: PUC issues order on rehearing addressing a number of concerns
OK	Implementation of SB 1456 (2014)-allow DG tariffs, prevent cost shift			Jun 16: Technical conference
OR	PGE community solar tariff option for resi/small C&I (Cases ADV 23 & UM 1020)			Jul 29: Tariff approved for 1 contracted solar project; future projects w/possible utility ownership TBD case by case
OR	Inquiry on resource value of solar/cost shift (Case UM 1716)	Commissioners workshop Prehearing conference	TBD TBD	Jan 27: Docket opened w/filing of 2015 biennial PUC report on solar incentive program Jul 20: Comment-VOS calculation
OR	Inquiry-determine a renewable generator's contribution to peak load capacity (Case UM 1719)	Public commissioner workshop	Aug 17	Jun 4: ALJ ruling-approve 3 staff-identified independent experts to participate in workshop
PA	PECO rate case incl. higher resi customer charge-from \$7.13 to \$12.02/mo. (Case R-2015-2468981)	Oral rejoinder testimony & hearings Evidentiary record closes Main briefs Reply briefs Decision expected	Aug 11-14 Aug 14 Sep 1 Sep 11 Dec 31	Jun 8-15: Public input hearings Jun 23: Non-co. direct testimony Jun-Jul: Settlement conferences; rebuttal & surrebuttal
PA	PPL rate case incl. higher resi customer charge-from \$14.09/mo. to \$.65753/day (~ \$20/mo.) (Case R-2015-2469275)	Oral rejoinder & evidentiary hearings Evidentiary record closes Main briefs Reply briefs PUC public meeting-deliberation	Aug 6,7,10,11 Aug 11 Sep 1 Sep 11 Dec 17	Jun 23: Direct testimony Jul 1: PPL objects to EDF intervention Jul 6: PPL asks ALJ to compel TASC responses to discovery Jul: Rebuttal; settlement talks

PA	PUC NOPR on NEM rule changes (Case L-2014-2404361)			May 9: Published in PA Bulletin May 29: Comments
RI	Rate design per HB 7727/SB 2690 (2014)-review of NGrid distribution rate design (Case 4568)	PUC meeting-discuss NGrid filings Intervention deadline Technical record session (tent.) Intervenor testimony PUC meeting-discuss testimony Staff direct testimony Technical record session NGrid rebuttal Staff/intervenor surrebuttal Evidentiary hearing w/public comment Hearings continue Decision deadline	Aug 13 Aug 31 Sep 17 Sep 30 Oct 15 Oct 30 Nov 18 Nov 25 Dec 16 2016 Jan 12 Jan 13-14 Mar 1	Jul 31: NGrid full rate design filing-4 tier resi customer charge based on customer size; approximates demand charge structure; proposed access fees for standalone generators ('parasitic' DG facilities directly interconnected w/distribution grid w/no associated on-site load)
RI	Rate issues review in preparation for generic rate design review per HB 7727/SB 2690 (Case 4545)			Jun 2: Staff & stakeholder meeting; PUC memo-meeting summary & next steps
SC	Duke Energy-new NEM tariffs per previous settlement (Cases 2015-204-E (DEP) & 2015-203-E (DEC))			Jun 2: Applications filed Jul 16: Comments, interventions
SC	Duke Energy-DER program (Case 2015-55-E, Duke Energy Carolinas; 2015-53-E, Duke Energy Progress)			May 12: Settlement-NEM retail rate, shared solar, cost recovery, rebates, utility solar Jul 15: PSC written order approving settlements, urging task force on consumer protection/education
SC	SCE&G-new NEM tariff per previous settlement (Case 2015-205-E)			Jun 2: Application filed Jul 26: Comments, interventions
SC	SCE&G-DER program (Case 2015-54-E)			May 26: Settlement-performance-based incentive for NEM customers, other provisions Jul 15: PSC written order approving settlement, urging task force on consumer protection/education
SD	NWE rate case w/resi customer charge increase-$5 to $9/mo. (Case EL14-106)	Staff/intervenor testimony Rebuttal testimony Evidentiary hearings	Sep 14 Oct 5 Oct 27-30	May 14: Public hearing May 29: NWE notice of intent to implement interim rates Jun 26: Scheduling order
TX	Entergy rate case-resi customer charge increase from $7 to $8.86/mo. (Case 44704)			Jul 17: Entergy withdraws rate case application Jul 20: ALJ dismisses w/o prejudice
TX	EPE community solar pilot (Case 44800)	Staff final recommendation or request for hearing If no hearing: Parties proposed orders	Aug 17 Aug 31	Jun 8: Application filed Jul 27: Intervenor comments

UT	PacifiCorp Subscriber Solar Program (Case 15-035-61)	Comments-all parties Response comments-all parties Company update Intervention deadline Reply comments-all parties Hearing	Aug 12 (rev.) Aug 27 Aug 27 Aug 31 Sep 15 Sep 21	Jun 16: Application filed Jul 10: Technical conference
UT	Generic proceeding on NEM costs and benefits (Case 14-035-114)	Rebuttal testimony Surrebuttal testimony Completion PacifiCorp study Decision-analytical framework Hearing	Sep 8 Sep 29 Sep End of 3Q Oct 6-8	Jul 1: PSC order-relevant costs & benefits are only those that accrue to utility & its non-NEM customers Jul 30: Testimony Aug 6: Interventions
VA	Dominion community solar pilot – utility-owned DG source, voluntary participation (NEM alternative) (Case PUE-2015-00005)			Aug 7: SCC approves settlement allowing pilot w/utility-owned DG
VA	KU rate case-increase resi customer charge from $12 to $15/mo. (Phase 1) & to $18/mo. (Phase 2 as of 1/1/17) (Case PUE-2015-00063)	Public hearing Intervenor testimony Staff testimony Co. rebuttal Written comments-interested persons Evidentiary & public hearing	Sep 24 Oct 6 Nov 16 Dec 3 Dec 7 Dec 14	Jun 30: Application filed
VA	NEM rulemaking per HB 1950/SB 1395 (2015)-raise nonresidential size cap, limit all size based on usage, other (Case PUE-2015-00057			Jun 5: Proceeding opened Jul 31: Comments
VT	Implementation of Act 99 (HB 702)-NEM rulemaking, undocketed	Initiate formal rulemaking	Summer	May 29: Staff report on working group meetings Jun 12: Comments Jun 18: Working group meeting
VT	Interconnection rule changes, undocketed			Jun: Staff draft rule, GMP proposed edits posted on PSB webpage Jun-Jul: Working group meetings Jul 30: PSB meeting-discussion
WA	Avista rate case incl. customer charge increase from $8.50 to $14/mo. (Case UE-150204)	Joint issues list Avista rebuttal; staff-intervenor cross-exam answering testimony Public comment hearing Discovery request deadline Cross-exam exhibits Evidentiary hearing Post-hearing briefs; updated jt. Issues list Decision expected	Aug 20 Sep 4 TBD Sep 22 Sep 30 Oct 5-8 Nov 4 Jan 11	May 1: Settlement-no change in resi customer charge Jul 27: Testimony
WA	UTC investigation of DG including costs/benefits (Case UE-131883)			Sep 17: UTC meeting-EPRI presentation, further discussion
WI	Xcel rate case-resi customer charge increase from $8 to $18/mo.; realign resi TOD rates (Case 4220-UR-121)	Public hearings Staff/intervenor testimony Rebuttal Surrebuttal	Sep 16 Oct 1 Oct 19 Oct 27	

		Party & public hearings	Oct 29	
		Initial briefs	Nov 12	
		Decision matrix	Nov 13	
		Reply briefs & positions on matrix	Nov 19	
		Expected decision	Dec 31	
WI	Xcel community solar pilot-up to 3 MW; subscribers receive mo. bill credit based on embedded electric production cost (Case 4220-TE-101)			Apr 27: Application filed May 27: PSC conditional approval: Xcel to work w/staff to I.D. avoided transmission costs & file reports
WI	WPS rate case-increase resi customer charge from $19 to $25/mo. (Case 6690-UR-124)	Intervenor/staff direct testimony Rebuttal testimony Surrebuttal testimony Prehearing testimony Public hearing session Party hearing session Initial briefs Reply briefs Staff-decision matrix outline Parties add positions to outline Staff final decision matrix	Sep 2 Sep 21 Oct 2 Oct 5 Oct 6 Oct 6 Oct 20 Oct 27 Oct 29 Nov 5 TBD	May 15: Rate design testimony Jun 11: Prehearing conference Jun 16: ALJ prehearing conference memo-lists intervenors incl. TASC, ELPC, CUB, Renew WI, industrial customer interests, others
WV	NEM task force-general investigation; responsive to new law (HB 2201) (Case 15-0682-E-GI)	Task force final report	Oct 5	May 28, 2015: 1st TF meeting Jun 3: Staff memo lists TF members incl. utilities, TASC

*Except where otherwise noted.

Note: For further information on state regulatory activity, please contact Martha Rowley, mrowley@eei.org This document no longer contains information on key state legislative activity, which is now reported separately. For information on state legislative activity, please contact Victoria Calderon, vcalderon@eei.org.

Abbreviation & Acronym Glossary

ACC – Arizona Corporation Commission
ALJ – administrative law judge
APCo – Appalachian Power Co.
APS – Arizona Public Service
AriSEIA – Arizona Solar Energy Industries Association
ARR – applicable retail rate
BCA – benefit-cost analysis
BHP – Black Hills Power
CA – consumer advocate
CCA – community choice aggregation
CE – Consumers Energy
CEP – Climate + Energy Project
CHG&E – Central Hudson Gas & Electric
CHP – combined heat and power
CL&P – Connecticut Light and Power
CMP – Central Maine Power
Cmte - Committee
ConEd – Consolidated Edison Co. of New York
COS – cost of service
CPUC – California Public Utilities Commission
CUB – Citizens Utility Board
CURB – Citizens' Utility Ratepayer Board
DEC – Duke Energy Carolinas
DEP – Duke Energy Progress
DER – distributed energy resources
DG – distributed generation
DGIP – distributed generation interconnection plan
DOC – Department of Commerce
DOER – Department of Energy Resources
DPU – Department of Public Utilities (MA) and Division of Public Utilities (UT)
DRP – distribution resource plan
DSIP – distributed system implementation plan
DSM – demand-side management
DTE – DTE Energy
E3 – E3 Consulting
EE – energy efficiency
EDC – electric distribution company
EDE – Empire District Electric
EDF – Environmental Defense Fund
EEI – Edison Electric Institute
ELPC – Environmental Law and Policy Center
ETIP – efficiency transition implementation plan
FPL – Florida Power & Light
GHG – greenhouse gas emissions
GM – grid modernization
GP – Georgia Power
GRC – general rate case
GSEIA – Georgia Solar Energy Industries Association
HECO – Hawaiian Electric Co.
ICC – Illinois Commerce Commission
IDSM – integrated demand-side management
IOU – investor-owned utility
IP – Idaho Power
IPA – Illinois Power Agency
IUB – Iowa Utilities Board
J&r – just and reasonable
KCP&L – Kansas City Power and Light
KU – Kentucky Utilities
LFE – late filed exhibits
LG&E – Louisville Gas and Electric
LIPA -- Long Island Power Authority
MassCEC – Massachusetts Clean Energy Center
MDPT – Market Design and Platform Technology
MG&E – Madison Gas and Electric
NEM – net energy metering
NIPSCO – Northern Indiana Public Service Co.
NOI – notice of inquiry
NOPR – notice of proposed rulemaking
NVE – Nevada Energy
NWA – non-wires alternative
OCC – Oklahoma Corporation Commission
OIR – order instituting rulemaking
ORU – Orange and Rockland Utilities
PBR – performance-based regulation
PD – proposed decision
PG&E – Pacific Gas and Electric
PNM – Public Service Co. of New Mexico
PRC – Public Regulation Commission
PSB – Public Service Board
PSIP – power supply improvement plan
PUC – public utility (or utilities) commission

PUD – public utility division
PURA – Public Utilities Regulatory Authority
RD – rate design
RE – renewable energy
REC – renewable energy credit (or certificate)
REPS – renewable energy and energy efficiency portfolio standard
RES – renewable electricity (or energy) standard
Resi – residential
REST – renewable energy standard and tariff
REV – Reforming the Energy Vision (NY)
Rev. – revised
RFI – request for information
RPS – renewable portfolio standard
RUCO – Residential Utility Consumer Office
SCE – Southern California Edison
SDG&E – San Diego Gas & Electric
SEIA – Solar Energy Industries Association
SGIP – Self-Generation Incentive Program
SOP – statement of position
TASC – The Alliance for Solar Choice
TEP – Tucson Electric Power
TF – task force
TOD – time of day
TOU – time of use
VNM – virtual net metering
VOS – value of solar
UC – Utilities Commission
URC – Utility Regulatory Commission
WEC – Washington Electric Cooperative
WEPCO – Wisconsin Electric Power Co.
WPS – Wisconsin Public Service
UC – Utilities commission
UTC – Utilities and Transportation Commission

An Evaluation of SRP's Electric Rate Proposal for Residential Customers with Distributed Generation

PREPARED FOR

Salt River Project

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THE Brattle GROUP

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Section 1: Introduction

1.1 Background

Residential customers are adopting distributed generation (DG), consisting largely of rooftop mounted solar panels, at a rapid rate, spurred on by income tax credits, falling prices of solar photovoltaic (PV) panels and a practice of electricity pricing referred to as net energy metering (NEM). Under NEM, DG customers only pay for their net purchases of electricity, i.e., their gross purchases net of their local generation of electricity.

While renewable energy sources such as rooftop solar are a vital part of the nation's energy supply, NEM embodies a latent subsidy between DG and non-DG customers. NEM credits DG customers for each unit of power they produce at the same retail rate at which they would otherwise buy it.

This creates two complications:

- The utility's retail rates include not only the cost of generating the electricity but also the cost of delivering the electricity, consisting of transmission lines, substations, distribution circuits, feeders and lines, line drops, and meters. When a DG customer installs solar panels on his rooftop, he reduces the utility's cost of generating electricity, and should be compensated for that at the utility's avoided generation cost. But the customer still requires a connection to the grid for those hours when his solar panels are not generating all of his electricity and for those hours when he over-generates. He still requires power be available from the grid in case the sun is not shining. He still requires a meter, a call center to answer questions about monthly bills, and other vital services. The DG customer, like all other customers, should still pay the utility for those services. But under NEM, the DG customer does not pay for these services.

- Someone else is forced to pay for these costs. It is the non-DG neighbor of the DG customer. Thus NEM amounts to the imposition of a hidden levy on the neighbors who don't own DG, creating a gross inequity between customers. In the end, it is not the utility that loses in this transaction but the customers without DG. These are often the less affluent customers, who are far less likely to have or be able to afford rooftop solar in the first place, and not the DG customers, who own single-family homes.

As a simplified example to illustrate this problem, suppose the retail rate for power is 11 cents/kWh, and that this rate has been set to cover the combined costs of energy and capacity (inclusive of generation, transmission and distribution). Suppose that the charge for energy is 4 cents per kWh, generation capacity is 2 cents per kWh, the charge for transmission is 3 cents/kWh and the charge for distribution is 2 cents per kWh. Only the energy component is a true variable cost that is sensitive to the volume of sales. The other three components are fixed or demand-related costs that are often embedded in the volumetric portion of the rate, based on the load profile of an average customer. When a DG customer installs solar equipment on his roof and generates a unit of electricity, the fair compensation for the DG customer is 4 cents/kWh. The customer has not offset the cost of staying connected to the electric grid, which provides transmission and distribution functions and backup generation.

However, under NEM, the DG customer is over compensated at 11 cents/kWh, even though he has not avoided the 7 cents/kWh cost for staying on the grid. The utility is then forced to make up its revenue shortfall by raising rates for all its customers. The problem is aggravated by the fact that today's rate designs for residential customers are largely volumetric in nature. The majority of the fixed costs of running the grid are recovered through a volumetric formula.

The best way for restoring fairness in rate design for DG customers is to move the fixed costs out of the volumetric charge and recover them through a fixed charge (i.e., dollars per month) and a demand charge (i.e., dollars per kilowatt of maximum demand per month). Smart meters are being rapidly deployed across the country, allowing the utility to measure not only the energy that customers consume per month, but the customer's demand on the grid as well. Furthermore, the 4 cents/kWh component for avoided energy costs could vary by time of day, as these costs are higher-than-average during afternoon and evening hours (often when the sun is shining) and lower-than-average during nighttime hours.

1.2 Purpose of Our Report

To address the issues of inequity and fixed cost recovery described above, SRP has proposed to introduce a new rate for residential customers who are planning to install DG capability.[1] This paper presents an evaluation of this proposal, using the pricing principles laid out by SRP's Board.

The paper does not address related policy issues such as decoupling, new regulatory models, caps on NEM participation, or changes to solar incentives like rebates and tax credits. It does also not address rate design issues for non-residential customers. It is focused entirely on residential DG rate design.

1.3 Principles of Rate Design

The SRP Board of Directors has laid out the principles against which rate designs should be evaluated. These principles provide the backdrop against which SRP's rate proposal for DG customers is evaluated.[2] The five principles are as follows:

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1 These customers are often referred to as self-generation customers.

2 Reproduced from "Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the April 2015 Billing Cycle," prepared by SRP, December 12, 2014.

- Gradualism – to enhance sound, economic decision-making by customers of all types through stabilizing price levels and smoothing the impact of cost movements that may be caused by temporary factors

- Cost Relation – to establish prices in relation to costs and SRP's stewardship to its water constituents, and thus not to pursue the maximization of "profit"

- Choice – to constantly improve customer satisfaction through the creative design of pricing structures that reflect customers' different desires or abilities to manage the consumption, assume more price control, or demand differentiated products and services, among others

- Equity – to treat customers of all types in an economically fair manner

- Sufficiency – to recover the cost of, and to invest and reinvest in a system of assets to perform its policy obligations, including its obligation to store and deliver water to the owners of land within the boundaries of the Salt River Reservoir District, to maintain SRP's financial well-being, and to follow the foregoing principles.

1.4 Organization of the Report

The rest of this report is organized as follows: Section 2 presents a conceptual menu of rate reform options, Section 3 reviews which of these options have found traction around the country, and Section 4 evaluates SRP's DG rate proposal.

Section 2: The Menu of Rate Reform Options

DG rates can be redesigned in a variety of ways to address the shortcomings described in Section 1. As background for the discussion of SRP's DG rate proposal, this section draws upon utility experiences in other regions of the country to present a variety of options for reforming rates for DG customers. It also discusses key decisions that must be made by utilities as they make the rate transition for future DG customers.

2.1 Rate Reform Options

Rates for DG customers can be redesigned to address the cross-subsidy discussed in Section 1 in a variety of ways. These include the following:

Introduce a demand charge. Utilities can introduce a demand charge ($/kW) for customers with DG, in addition to collecting from them a monthly fixed charge ($/month) and a variable energy charge ($/kWh). A demand charge is a charge based on a customer's maximum kW demand over a specified time period – typically the monthly billing cycle. It is typically based on the customer's maximum demand across all hours of the month or on their maximum demand during peak hours of the month, or sometimes on both. Since most capital grid investments are driven by demand, the idea is that demand charges will better align the price that customers pay with the costs that they are imposing on the system. Such a rate is also called a three-part rate and is commonly used for commercial and industrial customers.

Raise the fixed monthly charge. Most residential rates currently offered in the U.S. include a fixed monthly charge (sometimes called a customer charge or a customer service charge) that is approximately in the range of $5-$15/month along with an energy charge. While the size of the customer charge is generally consistent with the magnitude of fixed customer costs like metering, billing, customer care and other administrative services, it typically does not account for the fixed costs of generation, transmission, and distribution capacity that must be recovered by the utility over time. Increasing the fixed charge allows some or all of that capital investment to be recovered with relative certainty for the utility.

Impose a minimum bill. An alternative to a higher fixed monthly charge is a minimum bill. The minimum bill ensures that all customers will pay a minimum threshold amount each month. For instance, with a minimum bill of $50/month, a customer whose bill would have been $30 under the existing rate for a given month would be billed $50 for that month. In a different month, if the customer's bill under the existing rate would be $60, then the minimum bill feature would not come into play and their bill would remain unchanged. The theory is that the minimum bill amount can be associated with the average customer's cost of using the grid and therefore guarantee that amount to be recovered on a monthly basis.

Levy a capacity charge. A charge can be levied on DG owners based on the installed capacity of their DG systems. This results in an additional fixed monthly charge for DG owners, with the size of that charge being determined by the customer's generation capability. The reasoning behind this design is that customers with larger systems will self-generate more electricity, thereby avoiding paying a larger portion of their grid costs and justifying a larger offsetting incremental monthly charge on their bill.

Collect a DG output fee. Somewhat similar in concept to the capacity charge, a DG output fee would charge DG owners based on the total amount of electricity that they produce from on-site generation each month. In other words, the DG owners would still be paid for the electricity that they generate, but some of this payment would be offset by the DG output fee. Whereas the capacity charge is a dollars-per-kilowatt charge, the DG output fee is a dollars-per-kilowatt-hour charge. The DG output fee reflects the customer's cost of using the distribution system. This approach has also been referred to as a "bidirectional distribution rate."[3]

Collect a connection fee. DG owners could be charged a one-time grid connection fee at the time that they install on-site generation. The fee would be levied to recover the cost of the sunk investment in the grid that would still be used to serve these customers but which would otherwise no longer be recovered through their rates (under net energy metering conventions) once the DG system is installed.

Streamline the tiered rate structure. Some utilities currently offer a variable charge that increases with usage, commonly referred to as a tiered or inclining block rate (IBR) structure. For example, a customer might pay 10 cents/kWh for the first 300 kWh of electricity in a month, 15 cents/kWh for the next 300 kWh of consumption, and 20 cents/kWh for all additional consumption. In some regions, the price differential between the tiers bears no relationship to the underlying cost structure of electricity supply. Customers are motivated to install DG systems to avoid the non-cost based upper tier rates, creating an economic inefficiency. In these cases, the prices in the upper tiers could be reduced and the prices in the lower tiers could be increased to reduce the price differential between tiers. This "flattening" of the rate structure would reduce economic inefficiencies by bringing the incentive to install DG systems in line with the utility's cost structure.

Introduce time-varying rates. The variable charge can also be modified to include time-differentiated prices, with a higher price being charged during on-peak hours and a lower price during off-peak hours, reflecting the corresponding variation in utility capacity and energy costs by on-peak and off-peak periods. While this change by itself would not eliminate the cross-subsidies created by net energy metering, it would be consistent with the idea of modifying rates to better reflect the underlying cost structure.

Introduce a buy-sell arrangement. Many net energy metering policies compensate DG owners at the full variable charge in the retail rate. As discussed previously, when rates disproportionately collect revenue through that variable charge, DG owners are overcompensated for the electricity they generate. Under a "buy-sell" arrangement, DG owners would pay for all of the electricity

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3 Carl Linvill, John Shenot, and Jim Lazar, "Designing Distributed Generation Tariffs Well," prepared for the Regulatory Assistance Project, November 2013.

that they consume at the full retail rate, and would separately be compensated for all of the electricity that they generate at a price that more accurately reflects the value of the electricity being generated. This approach is also commonly referred to as a "value of solar" model, a feed-in-tariff (or "FIT"), or a dual meter tariff.[4]

2.2 Key Decisions in the DG Rate Transition

In addition to determining the specific design elements to be included in the reformed DG rate, there are a number of policy decisions to consider. The following are key questions that should be answered in a new DG rate proposal.

Should the new rate be offered only to DG owners or to all residential customers? Modifying the rate only for DG customers has the advantage of restricting the immediate bill impacts of the rate change to a small subset of the utility's customers. This limits the number of customer considerations that must be made when evaluating the rate. Since DG owners have a different load profile than other customers and are acting both as consumers and as generators, their unique status warrants the creation of a specific rate class. Offering special rates to DG customers is analogous to the development of "standby rates" for "partial requirements" customers in the commercial and industrial classes. Alternatively, if the proposed rate changes are cost-based and represent an overall improvement upon the existing rate structure according to sound principles of rate design, then it could be argued that only making these changes for DG customers is a missed opportunity to improve the rate design of the entire residential class.

Should current owners of DG be subject to the new rate design or should they be allowed to "grandfathered" onto the existing pricing policy? Typically, significant changes to the DG rate and/or the net energy metering policy have been accompanied by a grandfathering rule that allows existing DG owners to continue to be billed under the old pricing policy. The argument for this approach is that those customers made the decision to purchase their DG systems under a pre-established pricing agreement with the utility – or at least with the expectation that the existing arrangement would continue to be honored in the future. The grandfathering policy avoids placing an unexpected financial burden on those customers under the new pricing structure. The counterargument to such a grandfathering policy is that all investments are subject to the risk that future policies can change, and that DG investments are no different in this regard and should therefore not be given any special treatment.

Will the new DG rate be offered on a mandatory, opt-out, or opt-in basis? A mandatory rate offering ensures that all applicable customers will be enrolled in the newly designed rate. If it is desired to offer a choice of rates, then the new rate can be introduced on either an "opt-out" or "opt-in" basis. With an opt-out (or "default") offering, all customers are moved over to the new rate and then presented with the option to enroll in an alternative rate (or rates) if they choose.

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[4] There are nuanced differences in these approaches, mostly revolving around how to determine the price that is paid to DG owners for their power generation. But at a basic level, all of these approaches include a bifurcation of power purchases from the grid from power sales to the grid.

Research has found that with this approach most customers will continue to remain on the new rate.[5] With an opt-in offering, customers are presented the new rate as a voluntary option in which they must proactively enroll. Enrollment in the new rate will be the lowest with an opt-in approach.

Will the DG rate include a surcharge or will all modifications be revenue neutral? As discussed earlier in this section, DG rates may be modified to include a surcharge that is incremental to the rate that the DG owners would otherwise pay. This surcharge is intended to offset the DG owners' underpayment for their use of the grid. While this may have a cost basis, it is often met with resistance and characterized by some as a special "tax" on DG owners. An alternative approach is to modify the DG rate structure to better reflect system costs, but to make the changes in a way that is revenue neutral for the residential class. In other words, for the average residential customer, the new rate would produce the same bill as the old rate in the absence of any change in electricity consumption behavior.

5 Ahmad Faruqui, Ryan Hledik, and Neil Lessem, "Smart by Default," *Public Utilities Fortnightly*, August 2014.

Section 3: The National Landscape of DG Rate Reforms

There is widespread recognition in the US among regulators and utilities of the major issue raised in Section 2, that NEM creates unsustainable cross-subsidies from non-DG customers to DG customers. Efforts to reform residential rates to eliminate this NEM cross-subsidy are underway with varying degrees of success. This section presents a survey of recent state and utility DG rate reform activity.[6] These case studies illustrate the broad variety of approaches to rate reform. They are meant to be illustrative of the national landscape and not necessarily be exhaustive in coverage.

Each of the cases studies reflects its unique circumstances, metering capabilities and regulatory milieu. But there is a common element in many of the case studies. Just about all of them are proposing to raise the fixed charge in a two-part rate design construct. Some utilities are willing to proceed with the three-part rate design which includes a demand charge. Some feature a time-varying volumetric charge while others have decided to stay, at least for the time being, with a flat energy charge.

In some cases, the volumetric charge has an inclining block rate structure. While it is not always clear, it seems that existing DG customers will be grandfathered on the old NEM provisions for several years. That is how the issue of transition is being dealt with.

Some utilities are considering eventually extending the three-part for all residential customers. It is noteworthy that this is already the case for at least 10 utilities in a dozen states. But the offerings are optional unlike the practice for medium to large commercial and industrial customers where the offerings are mandatory or default (as in restructured markets). The issue of whether to make the three-part rate the standard rate for all residential customers continues to be debated. While there is universal agreement that that would be the optimal rate from an efficiency and equity perspective, the transition would create winners and losers with the attendant controversies.

Finally, some utilities are compensating DG customers using a "value of solar" construct rather than the retail rate. This is similar to the buy-sell arrangement being used by some utilities. In some cases, this involves compensating the DG customer at the wholesale power rate which is considerably lower than the retail rate. In other cases, it involves the inclusion of externalities that could result in a number that is higher than the retail rate.

Given the large volume of activity in DG rate reform, it is likely that these initiatives will continue to develop and evolve at a rapid pace.

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6 While utilities are frequently proposing a variety of changes to their rates, in this section we have focused specifically on those aspects of recent proposals that are designed to address fixed cost recovery.

Arizona: In July 2013, Arizona Public Service (APS) proposed a new NEM policy for DG owners. APS proposed two options. The first option would put DG owners on a three-part rate and continue to compensate them for their generation at the full retail rate. The second option was a buy-sell arrangement under which DG owners would have all consumption billed under one of the existing rate options, but they would be paid a lower wholesale rate for the electricity that they generate. In November 2013, the Arizona Corporation Commission instead voted to implement a $0.70/kW capacity charge for DG owners, equating to a surcharge of roughly $5/month for a typical residential rooftop solar installation.[7]

Additionally, APS offers the most highly subscribed three-part rate in the United States. Offered on an opt-in basis since the early 1980's, approximately 10 percent of APS's residential customers are enrolled in the rate, representing roughly 20 percent of residential sales.[8] Participants face a demand charge of $13.50/kW in the summer and $9.30/kW in the winter, as well as a $16.68/month fixed charge and a time-varying energy charge.[9] The rate option is available to all residential customers including DG owners.

California: In California, two of the three investor owned utilities (IOUs) currently do not have a fixed charge in their residential rate (San Diego Gas & Electric and Pacific Gas & Electric) and the third (Southern California Edison) has a nominal fixed charge of $0.94/month[10]. All three utilities have very small minimum bill requirements. Additionally, the residential rate is an inclining block rate with four tiers. The gap in prices has grown over time and now exceeds a ratio of 2:1.[11] In ongoing proceedings on redesigning residential rates, the utilities have proposed to reduce the number of tiers from four to two and to significantly reduce the price differential. They have also proposed a fixed charge of $10/month.[12] These changes would be phased in over a four-year period, and customers would also have the option to enroll in a variety of alternative time-differentiated rates.

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7 APS's Proposal to Change Net-Metering, ASU Energy Policy Innovation Council. Published October 2013, updated December 2013, p. 2, 3 and 5.

8 Based on FERC Form-1 Data from 2013 and 2014.

9 APS Rate Schedule ECT-2, Residential Service Time-of-Use with Demand Charge, Revised on July 1, 2012, p.1.

10 Notice of Southern California Edison Company's Supplemental Filing for Residential Electric Rate Changes (R/12-06-013, Phase 1), p.1 < >

11 PGE Website, < >, accessed 12/15/2014.

12 Renewable Energy World.com < >, accessed 12/19/2014.

In contrast, Sacramento Municipal Utility District (SMUD) has proposed to transition all of its residential customers to a rate with a time-varying volumetric charge and a $16/month fixed charge. The transition will occur over a multi-year period.[13]

Connecticut: Connecticut Light and Power (CL&P), a subsidiary of Northeast Utilities, recently requested an increase in its fixed charge from $16 to $25.50.[14] A December 17, 2014 decision by the Public Utilities Regulatory Authority (PURA) approved a smaller increase, raising the fixed charge to $19.25/month

Georgia: In its 2013 rate case, Georgia Power proposed a new tariff for DG customers in all classes. Specifically, the utility proposed to introduce a monthly capacity charge of $5.56/kW. For a 4 kW rooftop solar system, this translates into $22.24/month. The charge would have been entirely incremental to the existing rate. DG customers could avoid the capacity charge if they took service on a demand or RTP rate. However, in November 2013 Georgia Power withdrew its proposal as part of a settlement agreement with interveners. Residential rooftop solar owners continue to be billed under the utility's tiered rate structure, which has inclining tiers in the summer and declining tiers in the winter, and includes a $10/month fixed charge.[15] In that rate case, however, Georgia Power received approval for an optional three-part tariff with a time-varying energy charge for residential customers.

Hawaii: Hawaiian Electric Company (HECO) filed a Power Supply Improvement plan (PSIP) and a Distributed Generation Improvement Plan (DGIP) before The Hawaii Public Utilities Commission on August 26, 2014. The plan includes an illustrative $55/month fixed charge for all residential customers and an additional $16/month charge for DG owners, accounting for standby generation and capacity requirements. The filing also describes a "gross export purchase model" which compensates net energy metered customers at wholesale rates for the power they contribute to the grid.[16] However, this one of several possible scenarios described in the plans, and no formal request for a rate change has yet been filed with the commission. Both the PSIP and DGIP are under review by the Hawaii Public Utilities Commission.

Idaho: In late 2012, Idaho Power proposed to increase the fixed charge for residential net metering customers from $5/month to $20.92/month. With this proposal, Idaho Power would have also established a "basic load capacity charge" of $1.48 per kilowatt that would be applied to the average of the two highest billing demands for each customer's most recent twelve month

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13 General Manager's Report and Recommendation on Rates and Service, SMUD. May 2, 2013. Volume 1. < >, accessed 12/17/2014.

14 FOX CT news < >, accessed 12/19/2014.

15 Georgia Power Residential Service Schedule: "R-20", p.1

16 HECO Companies Propose Significant Charges for DG Customers, Green Energy Institute, September 24, 2014. < >, accessed on 12/14/2014.

period. These new charges would be offset by a reduction in the energy rates paid by net metering customers. The Idaho Public Utilities Commission rejected the rate design proposal in July 2013, stating these changes could be raised again in the context of a general rate case.[17]

Louisiana: Entergy proposed to reduce the net metering payment to DG owners, in recognition that solar-powered homes aren't paying for their full use of the grid. The Louisiana Public Service Commission rejected the proposal in June 2013, but agreed to conduct a detailed study on the costs and benefits of solar, and to revisit the issue when the enrollment cap on the state's net metering policy is reached.[18]

Minnesota: Minnesota has passed legislation that will allow its utilities to use a "Value of Solar" tariff (or buy-sell arrangement) as an alternative to traditional net metering. The measures of value that will ultimately determine the payment to DG generators are energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value.[19]

Nevada: In 2013, NV Energy received approval for an increase in its fixed charge for all residential customers in its northern service territory. The fixed charge was increased from $9.25/month to $17.50/month,[20] citing a desire by the PUC to adhere to a "cost follows causation" principle. Additionally, an initial proposal in the utility's southern territory included an increase in the fixed charge from $10/month to $15.25/month. However, the utility has since modified its proposal as part of a settlement process and is now seeking a $2.75/month increase, which the Nevada PUC is considering.[21] The increase in the fixed charge would be offset by a decrease in the volumetric charge, resulting in no net change in revenue.

South Carolina: A settlement agreement reached in December 2014 between utilities, conservation groups, and solar industry groups in South Carolina outlines key provisions for DG rates. One key provision dictates that rooftop solar owners be credited at the full retail rate. Additionally, charges cannot be levied exclusively on DG owners.[22]

Texas: Austin Energy began offering a "Value of Solar" tariff in October 2012. The tariff is similar in concept to the buy-sell arrangement offered by other utilities, although the payment to

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17 The Idaho Public Utilities Commission Website < >

18 Bird Lori, Updates on State Solar Net Metering Activities, NREL, September 23, 2014. < >, accessed on 12/19/2014.

19 Minnesota Value of Solar: Methodology, Prepared for Minnesota Dept. of Commerce, Division of Energy Resource, by Clean Power Research. January 30, 2014, pp. 1, 3.

20 SNL, "Basic service charge for many Sierra Pacific Power customers to nearly double Jan. 1," December 17, 2013. < >

21 Las Vegas Review Journal < >, accessed 2/15/2014.

22 SNL Website, < >, accessed 2/15/2014.

DG owners includes a number of components, such as environmental value and avoided fuel hedging costs, that tend to lead to a higher price paid to DG owners. The tariff also includes a floor price that ensures a minimum payment level to DG owners over a future time period.[23]

Utah: After several years of unsuccessful attempts to introduce a customer charge above $5/month, PacifiCorp (through subsidiary Rocky Mountain Power) proposed a surcharge of $4.65/month for DG customers, indicating that the charge would "produce the same average monthly revenue per customer for distribution and customer costs that is recovered in energy charges from all residential customers based on the cost of service study."[24] In its rate case testimony, the utility advised the Utah Commission that the surcharge was an interim measure and that in its next rate case it would be proposing a three-part rate designed specifically for partial requirements DG customers. The Public Service Commission of Utah did not approve the proposal, citing a need for further assessment of the costs and benefits of net metering.

Washington: PacifiCorp has proposed to increase its fixed charge from $7.75/month to $14/month. The proposal is packaged with a request for an overall rate increase. As in Utah, the utility advised the Washington Utilities and Transportation Commission that in its next rate case it would be proposing a three-part rate designed specifically for partial requirements DG customers. A decision from the commission is expected by March 2015.[25]

Wisconsin: In June 2014, Madison Gas & Electric (MGE) proposed to eventually transition all of its residential customers to a three part rate. The rate would have included an increased fixed charge, a flat variable charge, and two different demand charges. One demand charge was based on a customer's maximum demand during any hour (designed to collect distribution costs) and the other was based on a customer's maximum demand during peak hours (designed to collect system peak-driven costs). During the interim period of transition to this three-part rate, MGE proposed a fixed charge that would escalate over a multi-year period and eventually be replaced with the demand charges. MGE ultimately withdrew this proposal, and the Wisconsin Public Service Commission is instead expected to approve a $19/month fixed charge, which is an $8.50 increase over the current fixed charge of $10.50/month.[26] The commission is also expected to

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23 Austin Energy – Value of Solar Residential Rate, DSIRE website. < >, accessed on 12/14/2014.

24 PacifiCorp dba Rocky Mountain Power 2014 General Rate Case, Docket No. 13-035-184

25 Washington State Office of the Attorney General, October 10, 2014. < >, accessed 12/15/2014.

26 MGE website. < >, accessed 12/17/2014.

approve fixed charges of $16/month for We Energies[27] and $19/month for Wisconsin Public Service Company.[28]

It should be noted that there are currently at least 10 utilities offering three-part rates to residential customers in a dozen states. Although most of these rates have been offered for years and are not specific to DG customers, they share many characteristics with the rate proposals described above. The utilities currently offering a residential three-part rate are Alabama Power, Alaska Electric Light & Power ("AELP"), Arizona Public Service ("APS"), Black Hills (in South Dakota and Wyoming), Dominion (in Virginia and North Carolina), Duke Energy (in North Carolina and South Carolina), Georgia Power, Westar Energy, and Xcel Energy (in Colorado). The rates vary across characteristics such as the timing of demand measurement, the duration of the demand interval, and whether the energy charge is time-varying.[29] But all of the rates share the same basic common elements of the three-part rate: A demand charge, a fixed charge, and a variable charge. While these existing three-part from other jurisdictions are not specific to DG customers, they are useful for benchmarking SRP's proposed three-part rate design, as we do in Section 4.

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27 < >, accessed 12/17/2014.

28 < >, accessed 12/17/2014.

29 For more information, see Ryan Hledik, "Rediscovering Residential Demand Charges," *The Electricity Journal*, August/September 2014.

Section 4: SRP's Proposed DG Rate

Against the backdrop of the national experience with pricing electricity to DG customers, this section discusses SRP's DG rate proposal. It first summarizes the key elements of SRP's proposal as they relate to the various DG rate design options presented in Sections 2 and 3. It then provides an assessment of the extent to which SRP's proposal satisfies the ratemaking objectives presented in Section 1.

4.1 Key Elements of SRP's Rate Proposal

SRP is proposing a new three-part rate for its residential DG customers, referred to as the E-27 Customer Generation Price Plan. The rate is composed of three parts: a fixed monthly charge, a time-varying variable charge, and a demand charge.

The fixed charge varies by a customer's amperage (i.e., the size of their connection to the distribution system). It is $32.44/month for customers with 200 amps or less and $45.44/month for customers above 200 amps. Relative to the proposed fixed charge of $20/month for residential non-DG customers, that represents an increase in the fixed charge for all DG customers, driven primarily by an increase in the amount of distribution capacity cost that is recovered through the fixed charge.

The variable charge varies by time of day. There are two pricing periods, an on-peak period and an off-peak period, and the price of each varies by season. In the summer the on-peak period price is 4.86 cents/kWh and the off-peak price is 3.71 cents/kWh.[30] In the winter the on-peak price is 4.30 cents/kWh and the off-peak price is 3.90 cents/kWh. Additionally during the on-peak summer months of July and August, the on-peak period price rises to 6.33 cents/kWh and the off-peak period price rises to 4.23 cents/kWh, reflecting the higher cost of providing electricity in these months when air-conditioners are running heavily and demand for electricity is high.

The demand charge is tiered, meaning that the price increases with a customer's demand. It also varies by season. Demand is measured as the customer's maximum demand in any 15 minute interval during the on-peak period. In the summer, a customer's first 3 kW of demand are charged $6.61/kW, the next 7 kW of demand are charged $12.07/kW, and any additional demand is charged $22.98/kW. In the summer peak months (July and August), the demand charges are $8.10/kW, $15.05/kW, and $28.93/kW, respectively. In the winter, they are $2.87/kW, $4.57/kW, and $7.91/kW, respectively.

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30 In the summer (May 1 through October 31) the on-peak period is from 1 pm to 8 pm, Monday through Friday, excluding holidays. In the winter (November 1 through April 30) it is from 5 am to 9 am and from 5 pm to 9 pm, Monday through Friday, excluding holidays. The off-peak period is all other hours.

SRP has designed the rate to be revenue neutral for the typical DG customer before the customer has installed DG. The proposal includes a grandfathering clause that would allow existing DG customers to continue to be billed under the current pricing policy for 10 years. The rate applies only to DG owners and is a mandatory rate, meaning that they do not have a choice of alternative rate options.

4.2 Benchmarking SRP's Proposal

Several elements of SRP's DG rate proposal are similar to the proposals of other utilities discussed in Section 3.

SRP's decision to offer a three-part rate is mirrored by the proposals and/or existing rates of APS, MGE, and PacifiCorp utilities. APS currently offers an optional residential three part rate that is similar to SRP's proposal, with a time-varying energy charge and recovery of capacity costs primarily through a demand charge.[31] However, unlike SRP's proposed rate, APS's rate is available to DG customers as an option rather than being mandatory. SRP's proposal is also similar to the DG rates vision that has been established by PacifiCorp. Both SRP's proposal and the BHE proposal include a three-part rate that applies specifically to DG owners. MGE's originally proposed three part rate was also similar to SRP's design, but with the exception that MGE was proposing to make its rate mandatory for all customers rather than just for DG owners.

SRP's proposal to increase the fixed charge is similar to the recently approved fixed charge increases for Nevada Power and SMUD, as well as the proposal by CL&P, among other utilities. However, SRP's proposed fixed charge – ranging from $32/month for smaller customers to $45/month for larger customers – while aligned with SRP's fixed costs, is higher than the fixed charges of these utilities.

SRP's application of its new rate only to DG customers is also consistent with that of several other proposals. For example, the capacity charges included in the DG rates that were recently approved for Georgia Power and APS apply only to DG customers, as does the incremental fixed monthly charge proposed by HECO. This is in contrast to the recently adopted policy in South Carolina, for example, which dictates that any changes to rates for DG customers will also apply to all other residential customers.[32]

SRP's proposal to maintain its net metering policy of compensating DG owners at the full variable price in their rate is common to many of the proposals we have reviewed. In fact, at least 32 states have net metering policy that compensates the DG owner at the full retail rate for all electricity produced, including all net excess generation, and many more states credit at least a

31 APS's rate is the most highly subscribed three-part residential rate in the United States.

32 SNL Website, < >, accessed 2/15/2014.

portion of the electricity at the full retail rate.[33] This is in contrast to the buy-sell arrangements of utilities such as Austin Energy and the Minnesota utilities.

There are also some elements of SRP's proposal that are unique relative to the case studies discussed in Section 3. SRP seems to be the only utility that has proposed a tiered demand charge. It is not clear if any other utility has formally proposed a fixed charge that varies with a customer's amperage, although this is an idea that is frequently being discussed.

As discussed in Section 3, three-part rates are currently offered to residential customers by a handful of utilities across the United States. These rates are not specific to DG customers and are available to the entire residential class, potentially limiting their comparability to SRP's proposal. However, the comparison is still relevant for contextual purposes.

A comparison of SRP's demand charge to that of the other existing three-part rates is shown in Figure 1 and Figure 2. The first two tiers of SRP's demand charge generally fall within the range of demand charges being offered by other utilities. The third tier price is higher than other rate offerings. For comparability, the charts also show the average demand charge for a customer with 10 kW of monthly demand. On average, an SRP DG customer with 10 kW of demand would pay $10.43/kW in the summer (including the summer peak months of July and August), and $4.06/kW in the winter, prices that are generally within the range of these other rate offerings. Smaller customers, of course, would pay a lower average price for demand and larger customers would pay a higher average price.

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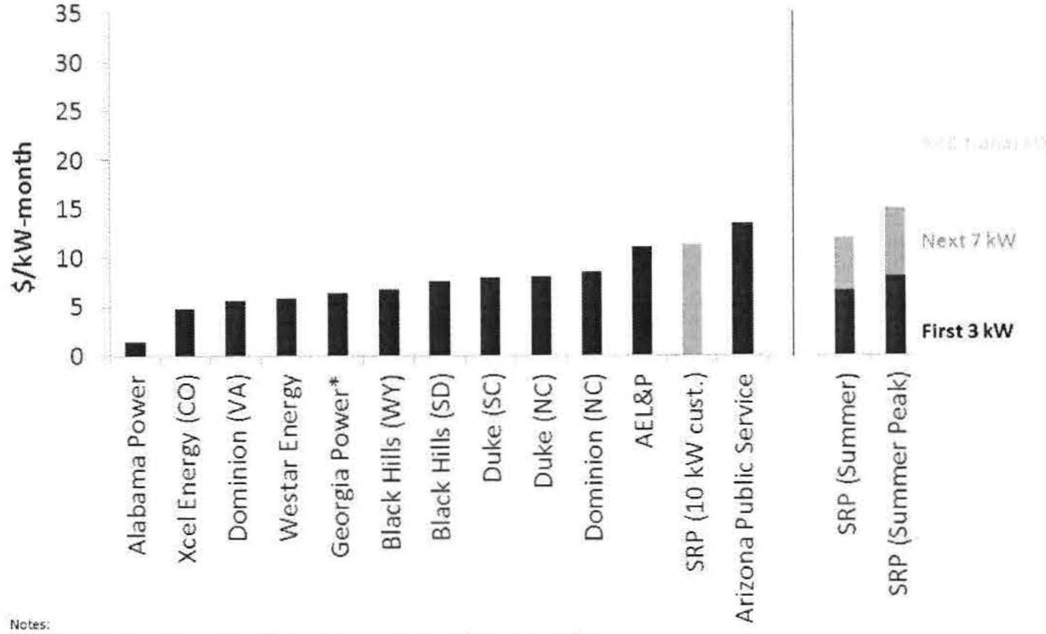
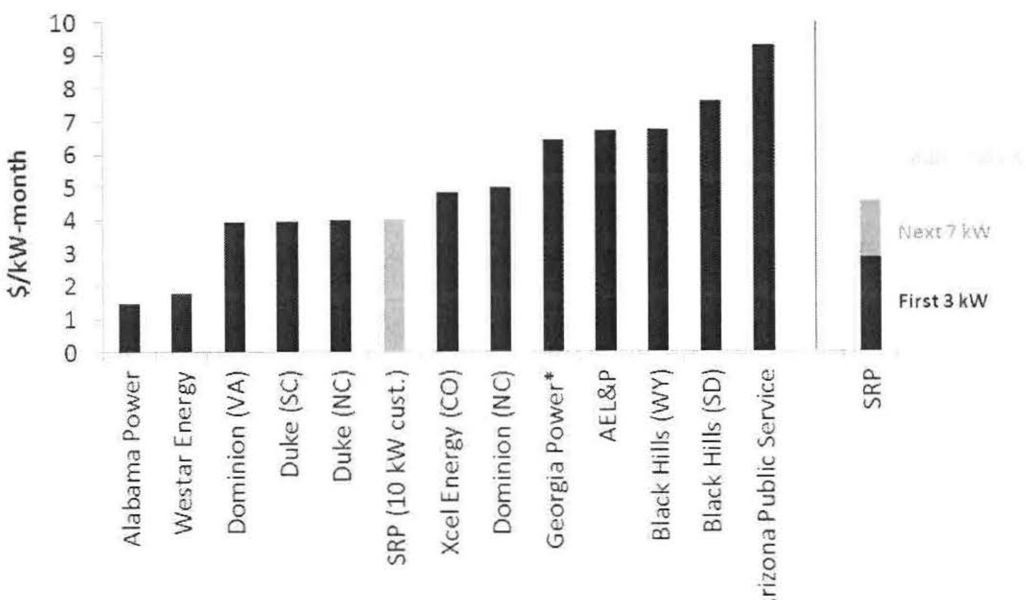
[33] DSIRE database on net metering < >. We considered the net metering policy for all states and the District of Columbia. Only states where compensation amount was a function of retail rates were included.

Figure 1: Summer Demand Charge in Residential Three-Part Rates



Notes:
Georgia Power's rate is a proposed modification to its existing rate and approval is pending.
Westar's rate is currently closed to new enrollment.
Rates are from utility tariff sheets as of May 2014.

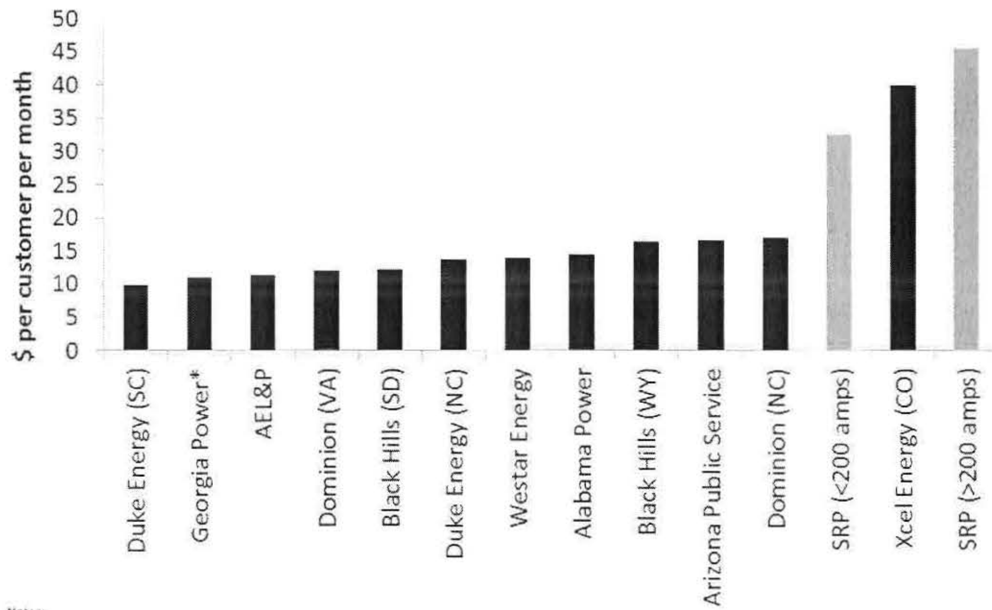
Figure 2: Winter Demand Charge in Residential Three-Part Rates



Notes:
Georgia Power's rate is a proposed modification to its existing rate and approval is pending.
Westar's rate is currently closed to new enrollment.
Rates are from utility tariff sheets as of May 2014.

SRP's proposed fixed charge is compared to the fixed charge of the other three-part rate offerings in Figure 3. SRP's fixed charge is similar to that of Xcel Energy but significantly higher than the other rate offerings. This difference is likely explained by the fact that SRP's rate collects a larger portion of distribution costs (i.e., the Distribution Facilities Charge) than is collected by the other rates.

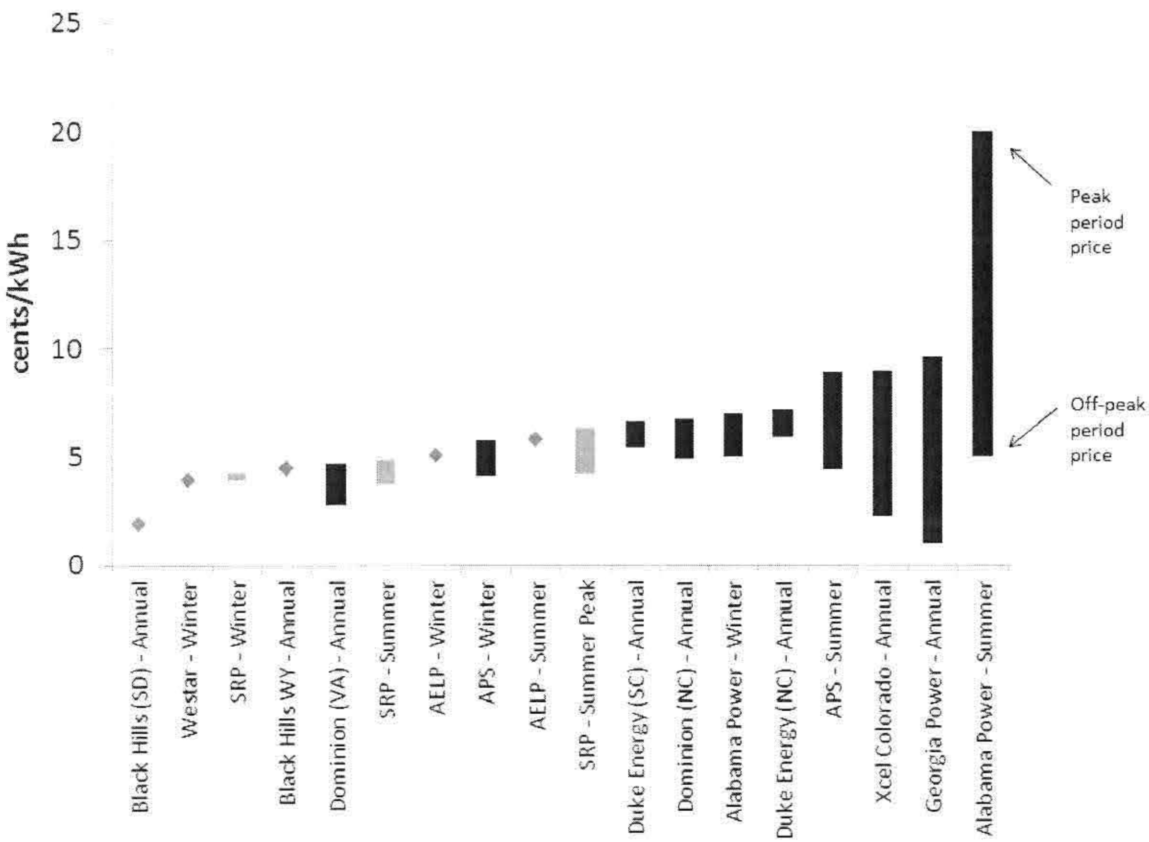
Figure 3: Fixed Charge in Residential Three-Part Rates



Notes:
Georgia Power's rate is a proposed modification to its existing rate and approval is pending.
Westar's rate is currently closed to new enrollment.
Rates are from utility tariff sheets as of May 2014.

SRP's variable charges are lower than around half of those in the three-part rates being offered today. Figure 4 shows this comparison. The height of the bars represents the difference between the peak period price (the top of the bar) and the off-peak period price (the bottom of the bar) for rates with a time-varying energy charge. Rates that do not have a time-varying energy charge are represented with a gray diamond.

Figure 4: Energy Charges in Residential Three-Part Rates



4.3 Assessing the Proposal

SRP's proposed Customer Generation Price Plan has very significant advantages over the current rate offering. Perhaps most importantly, the proposal's three-part rate structure aligns much more closely with the underlying cost of supplying electricity to customers. By collecting demand-related costs through a demand charge, fixed costs through a fixed charge, and variable costs through a time-varying variable charge, SRP's proposal satisfies the ratemaking objectives of economic efficiency and "cost causation." By better reflecting costs, the rate will address the inequities that exist in the current rate designs, particularly as they relate to the under-recovery of fixed costs from DG customers.

The recovery of capacity costs through a demand charge is a particularly attractive feature of the rate. This will credit DG customers for the peak-coincident capacity that they provide to the system. By recovering capacity costs through a demand charge rather than a fixed charge, SRP's proposal avoids the challenge of automatically increasing bills for small customers, a common argument against high fixed charges. And unlike a fixed charge, the demand charge provides customers with a strong incentive to lower their bills by reducing their kW demands. Finally, since demand charges have been offered to commercial and industrial customers for decades, there is well established precedent for designing such rates, enrolling customers, handling calls and doing all the other activities that attend to their offering. With smart meters fully deployed across SRP's service territory, there is no longer a technical barrier to offering these rates to residential customers.

The time-varying and seasonal nature of the volumetric charge is another attractive feature of the rate. Since energy costs vary over the course of the day, capturing this variability in the rate structure helps to ensure that customers face accurate price signals when making decisions about their electricity consumption behavior.

SRP's NEM policy is also a strong feature of the proposal. With a cost-based three-part rate, it is not necessary for SRP to modify its current NEM arrangement of compensating DG owners for their electricity production at the full variable rate. In other words, SRP has not proposed to implement a buy-sell arrangement, since there is no strong and compelling reason for them to do so. As designed, the rate will sufficiently recover fixed costs from those who impose the costs on the system, while compensating them at a fair rate for the electricity that they generate.

SRP's plan to allow current DG owners to continue to be billed under their current rate for a period of 10 years is also a positive feature of the proposal. This grandfathering policy will facilitate the transition to the new rate by ensuring that customers will not experience bill increases when the rate is rolled out. Those customers who are considering investing in DG will be able to do so with complete information about their future pricing structure.

Overall, SRP's proposed rate is well designed and represents a significant improvement over the current offering. A three-part rate is perhaps the most effective way to satisfy the principles of economic efficiency and cost causation, reduce inequities in existing rates, and provide customers with an opportunity to reduce their bills through smarter energy management. It is the ideal DG rate design.[34]

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[34] In the future, SRP may wish to further refine its rate offerings. Two are discussed here. First, SRP might want to consider incorporating two demand charges into the rate. In addition to the currently proposed demand charge, which is constrained to the peak hours of the day, a second demand charge would be based on the customer's maximum demand at any point in the day. Adding the second demand charge could further improve the extent to which the rate reflects SRP's underlying cost structure, although such a change would need to be made with considerations for the tradeoff with simplicity and a customer's ability to understand and act on the rate. And, second, SRP might consider making the three-part rate the standard for all of its residential customers, not just its DG customers. This rate design has a number of distinct advantages over the existing residential rate options. Deploying the rate to all residential customers would require that the rate rollout be accompanied by a carefully designed customer education and outreach plan that is informed by market research. Other customer protections, particularly for vulnerable customers, may also be needed.

Additional Resources

American Public Power Association, "Distributed Generation: An Overview of Recent Policy and Market Developments," November 2013.

Beach, R. Thomas and Patrick G. McGuire, "Evaluating the Benefits and Costs of Net Energy Metering in California," prepared for The Cote Solar Initiative, January 2013.

Bird, Lori, "Update on State Solar Net Metering Activities", RPS Collaborative Summit, NREL, September 23, 2014.

Darghouth, Naim, Galen Barbose, Ryan Wiser, "The Impact of Rate Design and Net Metering on the Bill Savings from Distributed PV for Residential Customers in California," Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division, April 2010.

Edison Electric Institute, "A Policy Framework for Designing Distributed Generation Tariffs," December 2013.

Institute for Electric Efficiency, "Value of the grid to DG Customers," September 2013.

Institute for Electric Innovation, "Net Energy Metering: Subsidy Issues and Regulatory Solutions," Issue Brief, September 2014.

Linvill, Carl, John Shenot, Jim Lazar, "Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition," November 2013.

Salt River Project Agricultural Improvement and Power District, "Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the April 2015 Billing Cycle," December 12, 2014.

Solar Electric Power Association, "Ratemaking, Solar Value and Solar Net Energy Metering – A Primer," August 2012.

U.S. Department of Energy, SunShot, "Standby and Fixed Cost Charges and Net Energy Metering Debates: Current Status," August 2014.

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MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

TASC-029
RE: Impact of new demand charge on future electric demand

Please provide all studies, analyses, workpapers, memoranda, or other documents prepared by MDU relating to the impact of the proposed Rate 92 on future demand for electricity.

Response:

No such studies exist.

MONTANA-DAKOTA UTILITIES CO.
ALLIANCE FOR SOLAR CHOICE'S
DATA REQUEST
DATED SEPTEMBER 29, 2015
DOCKET NO. D2015.6.51

TASC-030
RE: Effect of Rate 92 on utility revenues

Provide an estimate of the increased revenues that MDU expects to receive as a result of proposed Rate 92 for each of the following years: 2016; 2018; 2020; 2022; and 2024, or any such other years as the company had data or analysis.

Response:

Based on the actual data for calendar year 2014 and estimated demand, incremental revenues of approximately $77 would be generated under the Company's proposal. Future years will depend on the number of net metering customers present on the system and the load and generation profile of each net metering customer.