Office of the Secretary
Service Date
August 26, 2020

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER TO CLOSE THE NET METERING PROGRAM TO NEW SERVICE & IMPLEMENT A NET BILLING PROGRAM TO COMPENSATE CUSTOMER-GENERATORS FOR EXPORTED GENERATION	)	**CASE NO. PAC-E-19-08** **ORDER NO. 34753**

On June 14, 2019, Rocky Mountain Power, a division of PacifiCorp ("Rocky Mountain Power" or "Company") applied to the Commission for an order closing Electric Service Schedule 135 – Net Metering Service ("Schedule 135" or "Net Metering Service") to new customers after December 31, 2019, and opening Electric Service Schedule 136 – Net Billing Service ("Schedule 136" or "Net Billing Service") to new customers as of February 1, 2020 ("Original Application").

On July 18, 2019, the Commission issued a Notice of Application and Notice of Intervention Deadline. Order No. 34379.

On December 20, 2019, the Commission issued a final order in IPC-E-18-15 rejecting a proposed Settlement Agreement for Idaho Power's net metering program. Order No. 34509. On February 5, 2020, the Commission issued a final order on reconsideration in IPC-E-18-15 upholding its decision to reject the proposed Settlement Agreement. Order No. 34546.

On March 10, 2020, the parties met to discuss how to proceed with Rocky Mountain Power's Application given the Commission's directives in Order Nos. 34509 and 34546 issued in IPC-E-18-15.

On April 23, 2020, Rocky Mountain Power submitted a supplemental application ("Supplemental Application"). The Supplemental Application proposed closing Schedule 135 to new customer's as of July 31, 2020, and opening Schedule 136 as of September 1, 2020. The Supplemental Application also updated inputs to the Company's proposed export credit rate ("Export Credit Rate").

On May 6, 2020, the Commission issued a Notice of Supplemental Application, Notice of Public Hearing, and Notice of Comment Deadlines. Order No. 34661. The Commission set a procedural schedule designed to allow the parties to integrate customer feedback into their respective comments. The Commission set a deadline of May 26, 2020 for initial comments, July

3, 2020 for revised comments, and a deadline of July 16, 2020 for party reply comments and public comments on the study design phase. The Company hosted a telephonic public workshop on June 16, 2020. Commission Staff hosted a live-streamed public workshop on June 18, 2020. The Commission held a telephonic public hearing on June 22, 2020.

On July 31, 2020, the Commission suspended the Company's proposed effective date. Order No. 34745.

Idaho Irrigation Pumpers Association, Inc., Idaho Conservation League ("ICL"), Idaho Clean Energy Association, Inc. ("ICEA"), and Monsanto Company intervened as parties.

Now, the Commission issues an order defining the scope of the study to be conducted by the Company. Concurrently and separately, the Commission issues Order No. 34752, a proposed order on grandfathering existing customer-generators pursuant to Commission Rule of Procedure 312.

BACKGROUND

The Company's Net Metering Service was first approved by the Commission in 2003 in response to a petition from the NW Energy Coalition and Renewable Northwest Project. Order No. 29260. Schedule 135 was modeled on Idaho Power's Schedule 84. *Id.* at 6. Schedule 135 allows for monthly netting of energy production and consumption. Under Schedule 135, net monthly generation is compensated by an export credit at the customer's retail rate, which can be carried forward indefinitely, transferred among meters in the customer's name on contiguous property, and applied to the customer's bills for net consumption of electricity. In approving the Company's proposed tariff, the Commission stated, "This opportunity to run the meter backwards and offset usage is the primary purpose of net metering." *Id.* The Commission said, "The purpose of net metering is not to encourage excess generation. Developers of qualifying renewable generation resources who wish to get into the business of selling energy to the Company should, under [the Public Utility Regulatory Policies Act of 1978] request firm or non-firm energy purchase contracts." *Id.* at 6-7.

In 2016, the Company petitioned the Commission to raise the cap on overall customer participation from 714 kW to 2,000 kW. The Commission agreed to remove the 714 kW cap but declined to impose the 2,000 kW cap, finding "the cap did not serve its intended purpose, the Company has not expressed any immediate reliability concerns, the subsidization level is currently small but growing, and the Company plans to propose modifying the net metering service and rate design to address subsidization as part of its next general rate case. Order No. 33511 at 7. The Commission directed the Company to file a report annually. The Commission stated the report "should discuss, without limitation, customer participation levels, generator types, nameplate capacity, total generation, contribution to system peak, impacts on non-net metering customers, potential impacts to power quality and reliability, etc." *Id.* These reports are available on the Commission website in the PAC-E-16-07 case file.

This case was originally filed on June 14, 2019 while the Commission was processing two net metering cases for Idaho Power, IPC-E-18-15 and IPC-E-19-15. When the Commission denied the proposed Settlement Agreement in IPC-E-18-15, the Commission prescribed a procedure and criteria to ensure an open and robust review of future Idaho Power net metering proposals. The Commission identified the need for a credible and fair study to form the basis of proposed changes to net metering service offerings and identified three criteria for a credible and fair study. 1) The study must use the most current data possible and the data must be readily available to the public and in the Commission's decision-making record. 2) The study must be designed in coordination with the parties and the public, including opportunities for public participation in the study design and the study review phase with the final scope of the study to be determined by the Commission. 3) The study must be written to be understandable to the average customer but withstand expert scrutiny. Order No. 34509 at 9. The parties to this case proposed a schedule based on the directives in the IPC-E-18-15 orders. *See* Supplemental Application at ¶ 14. This order completes the "study design" phase and determines the scope of the study the Company is to undertake.

SUPPLEMENTAL APPLICATION

The requests for relief in the Company's Supplemental Application can be summarized as requests for the Commission to: 1) close Schedule 135 to new participants and grandfather existing customer-generators on Schedule 135 for ten years; 2) open Schedule 136 to new customer-generators; 3) impose an $85 application fee for Schedule 136 applicants; and 4) allow the Company to recover export energy credits through the Company's Energy Cost Adjustment Mechanism ("ECAM"). In Order No. 34752, the Commission's proposed order addresses all but the ECAM request.

In its Original Application, and supporting testimony, the Company proposed immediate implementation of an Export Credit Rate upon the Commission opening Schedule 136.

Original Application at ¶ 12, MacNeil, Di. At 1-2. In its Supplemental Application, the Company requests the Commission establish Schedule 136 on the same terms as Schedule 135 but with an Export Credit Rate initially set at the customer's retail energy rate until the Commission approves and implements an Export Credit Rate. Supplemental Application at ¶ 22.

The proposed method for calculating the Export Credit Rate is the same in the Original Application and the Supplemental Application, although the Supplemental Application uses updated inputs. In the Original Application, the Export Credit Rate was calculated to be $24.86 per MWh. MacNeil, Di at 2. In the Supplemental Application, the Export Credit Rate was calculated to be $22.34 per MWh. Supplemental Application at ¶ 16. The Company proposes these values "be differentiated by on-peak / off-peak and summer / winter periods that reflect higher and lower avoided cost values . . ." MacNeil, Di at 13.

The Company proposes to calculate the avoided energy component by using a time-differentiated variation of the Commission's Surrogate Avoided Resource methodology ("SAR Method"). The Commission uses the SAR Method to calculate published avoided cost rates for qualifying facilities under the Public Utility Regulatory Policies Act of 1978. The SAR Method is based on the fixed costs and operations and maintenance costs required to build and operate a hypothetical Combined Cycle Combustion Turbine ("CCCT") natural gas power plant. The SAR Method uses natural gas forecasts and an assumed heat rate for CCCTs to calculate what the operation costs would be for the hypothetical plant.

The Company proposes to modify the SAR Method to account for the different value of energy provided by customer-generators at different times of day and in different seasons of the year, and to reflect the Company's description of the resource as "non-firm." The Company states non-firm pricing is appropriate for on-site generation customers because, "Firm contracts would include credit terms, security deposits, performance guarantees, liquidated damages, default provisions, and termination rights that are not found in the Schedule 136 tariff." MacNeil, Di-3-4. Therefore, the Company proposes a 15% reduction to the Export Credit Rate to reflect the non-firm nature of the resource. *Id.* at 3.

Under the Company's proposal to calculate the hourly Export Credit Rate, the Company assigns a value to each hour of the day based on that hour's historic relation to average market price, as measured by the Company's PacifiCorp east ("PACE") Energy Imbalance Market ("EIM") for the most recent 12-month period. *Id.* at 4. The Company uses the example, "For instance, if the average market price during hour-ending 10 in May is $18/MWh, and the average market price during all hours in May is $20/MWh, then the scalar for hour-ending 10 in May would be 90 percent." *Id.*

The Company further adjusts this value by applying on-peak and off-peak pricing. The Company proposes to define on-peak pricing as 4:00 p.m. to 10:00 p.m. Mountain Time, Monday through Friday excluding holidays. *Id.* at 9. The Company proposes the Export Credit Rate be 52% higher for exports during on-peak hours than off-peak hours. *Id.* at 10. The Company also differentiates energy values based on season, assigning higher values during the seasons in which there is higher demand for energy, and lower values in seasons in which there is lower demand for energy. The Company proposes the summer season be defined as June through September. *Id.* at 11.[1] The Company proposes to update the Export Credit Rate annually concurrent with the annual update to the SAR Method on June 1. MacNeil, Di at 11.

For avoided line losses, the Company proposes to use its 2009 Analysis of System Losses for Idaho. MacNeil, Di at 5. The Company states the study identified line losses of 4.53% at the transmission level, 7.448% at the primary level, and 11.466% at the secondary level. *Id.* at 5-6. The Company states it "used the results from power flow studies to calculate a marginal loss by load level and then fitted it to a 12 month by 24-hour profile for each of the interconnection levels referenced above. The result is an estimate of avoided line losses that can be differentiated by time of day and can be used to determine specific on-peak and off-peak values." *Id.* at 6. The Company proposes to credit on-site generators only for avoided primary line losses. *Id.* The Company calculates the average value of avoided line losses during the 12 months ending May 31, 2021 to be $3.36 per MWh. Supplemental Application at ¶ 17.

For integration costs, the Company proposes to use the costs to integrate utility-scale solar resources, as determined in its 2017 Flexible Reserve Study. The Company states that the study "identifies the amount of flexible capacity required to compensate for variations in load and resources, as well as the cost of that capacity." MacNeil, Di at 7. After adjusting for inflation, the Company proposes an integration of $0.64 per MWh. *Id.*

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[1] In direct testimony supporting its Original Application, the Company calculated on-peak rates during the summer months of 3.926 cents per kilowatt-hour ("kWh") and 3.113 cents per kWh for October through May. The Company calculated off-peak rates of 2.183 cents per kWh for summer months and 2.356 cents per kWh for all other months. Meredith, Di at Exhibit 5. The Company did not provide updated seasonally differentiated on-peak/off-peak rates as part of its Supplemental Application.

The Company proposes to move away from the monthly netting of energy imports and exports by a customer-generator and instead calculate the customer-generator's exports/imports on an instantaneous basis. Meredith, Di at 15. That is, if a customer-generator is exporting at any given moment (producing more energy than they are consuming) the customer-generator would receive the Export Credit Rate for the energy they are exporting to the grid. If the customer-generator is importing (consuming more energy than they are producing), at any given moment, that customer-generator would pay the applicable retail rate for energy for the energy they are importing from the grid. The Company proposes that export credits roll over until March of each year for most customer-generators and until October for irrigation customers. Meredith, Di at 17.

The Company proposed to close Schedule 135 to new participants as of July 31, 2020, and open Schedule 136 as of September 1, 2020. Both dates have been suspended by the Commission. The Commission issued a proposed order that, if adopted, would close Schedule 135 to new participants on or after September 24, 2020, and open Schedule 136 to new participants as of October 1, 2020. Initially, the new Schedule 136 will contain the same terms as Schedule 135, but the terms of Schedule 136 will be subject to change whereas the terms of Schedule 135 will be locked in place for 25 years if the Commission adopts the proposed order. Order No. 34752

The Company does not propose changes to retail rates for consumption in its applications. *See* Supplemental Application at ¶ 2. The Company filed a Notice of Intent to File a General Rate case on March 26, 2020. The Company later decided, due to the impacts of the COVID-19 pandemic, to delay filing a general rate case and instead apply for an accounting order, which would not immediately change customer rates. *See* Order No. 34731.

COMMENTS

A. Commission Staff.

Staff recommends the Commission order the Company to study numerous aspects of an on-site generation program beyond what was included in the Company's proposal, as well as study certain aspects and assumptions of the Company's proposal. Staff's initial comments identified general areas of study, and Staff's revised comments incorporated customer concerns and refined these general areas of study into specific questions. Staff relayed customer concerns expressed at its June 18, 2020, live-streamed public workshop and in public comments. For example, Staff states that customers strongly objected to the Company's proposal for export credits to expire annually, proposed methods to quantify the impact of export credit expiration over different time periods, and requested greater explanation on this issue. Staff Revised Comments. at 12-13.

Staff provided a list of 31 questions it would like answered on a variety of topics fundamental to on-site generation program design. Attachment A to Staff Revised Comments. For example, Staff recommends the Commission order the Company to study the avoided capacity value provided by customer-generators as a class either through a Loss of Load Probability method or using a 99.5% reliability threshold. Staff Revised Comments at 9. Staff recommends the Company study avoided transmission and distribution costs provided by customer-generators according to methods used by the Company to calculate avoided transmission and distribution costs for energy efficiency. *Id.* at 11. Staff recommends study of how the Company will recover export credit costs through the Company's ECAM. *Id.* at 7. Staff also requests study on the Company's use of modeled data as opposed to actual customer data. *Id.*

B. Idaho Clean Energy Association.

ICEA focuses its comments on the impacts to residential on-site installers and the impacts to potential and present customer-generators. "ICEA believes that any changes to the Company's net metering program should be 1) understandable to solar installers and to customers; and 2) proportional to the underlying issue that the changes are trying to address." *Id.* at 2. ICEA adds, "In the long run, simplicity, and proportionality should promote understanding and compliance by installers and customers alike." *Id.* at 2. In the vein of simplicity and understandability, ICEA's comments focus on the potential impacts of a move to net hourly billing. *See id.* at 3. ICEA expresses an interest in smart inverters and requests that if any changes to smart inverter requirements are to be proposed that the changes be identified and included within the scope of the study. *See id.* at 4-5.

C. Idaho Conservation League.

ICL makes numerous arguments as to why it would be appropriate to defer the study. ICL notes that Rocky Mountain Power proposes to make program changes before the conclusion of the study. ICL Initial Comment at 2. ICL notes that the current level of participation in Rocky Mountain Power's on-site generation program is small based on customer-generators, exported energy, and revenue involved, and questions whether the administrative burden of processing the case will result in ratepayer benefits. *Id.* at 2-3. ICL requests delaying the study until actual data is available from Advanced Metering Infrastructure in the Company's service territory, rather than relying on modeled data. *Id.* at 4. Meanwhile, ICL recommends conducting a Load Research Study like that conducted in Rocky Mountain Power's Utah service territory. *Id.* ICL also requests study of potential benchmarks to assess when market penetration will justify program design changes. *See id.* at 3-4.

Like ICEA, ICL requests study on the ability of net metering service providers to implement net hourly billing. ICL expresses concern that annual updates to the Export Credit Rate and more granular pricing may make it extremely difficult for installers to comply with the Residential Energy System Disclosure Act. *See id.* at 3. ICL also requests study of the impact to the Idaho on-site generation market including impacts on local employment, tax revenues, and the ability of customers to participate. *Id.*

ICL requests the Commission order the Company to study whether overall production from on-site generation systems is predictable and reliable and therefore firm. *See id.* at 5. Instead of using a single node on the Energy Imbalance Market to determine avoided energy costs, ICL recommends study of Rocky Mountain Power's actual hourly costs and comparing those costs to the EIM data. *Id.* at 6. ICL recommends studying project eligibility caps based on 100% or 125% of customer load instead of a specific kW project eligibility cap. ICL asserts that doing so complies with prior Commission orders that define on-site generation as a means for customers to offset their own demand. *Id.* at 8. ICL also recommends studying the use of smart inverters and different smart inverter settings that can improve power quality and improve visibility of systems to the Company. *Id.* In its revised comments, ICL notes that public comments identified the issue of unused excess energy credits and their expiration. ICL Revised Comment at 2. ICL notes and supports a customer comment requesting unused excess energy credits be donatable to other customers unable to pay their bill. *Id.* at 2.

D. Rocky Mountain Power.

In its revised comments, the Company responded to public and party comments regarding its proposal to grandfather customers and amended its proposal from 10 years to 15 years. In its reply comments, the Company addressed Staff's proposed areas of study by either pointing to information on the record, asserting the proposed areas of study are not properly included in rates, agreeing an item may be appropriate for study elsewhere or at another time, asserting a misunderstanding, restating its proposal, or stating the Company may consider a different proposal.

COMMISSION FINDINGS AND DECISION

The Commission has jurisdiction over this matter under *Idaho Code* §§ 61-502 and 61-503. The Commission is empowered to investigate rates, charges, rules, regulations, practices, and contracts of public utilities and to determine whether they are just, reasonable, preferential, discriminatory, or in violation of any provision of law, and to fix the same by order. *Idaho Code* §§ 61-502 and 61-503. The Commission may enter any final order consistent with its authority under Title 61.

The "two-phase" approach used to process the Company's Supplemental Application is a new process for all parties involved. It is designed to solicit and incorporate public feedback at pertinent stages and ensure a reasonably comprehensive study of the issues is conducted in a credible and fair manner. The study will be one critical component of Commission review but will not preclude the parties from introducing and the Commission considering other relevant pieces of information when it is time to address proposals for new program implementation. The Commission notes that the two-phase approach has offered the public adequate opportunity to comment during the study design phase, despite difficulties associated with COVID-19. Commission Staff and the Company each held live-streamed public workshops following their initial comments and before submitting their revised comments. And the Commission held a telephonic public hearing, providing customers the opportunity to comment on the record following the initial comments and before revised comments were submitted.

Having reviewed the record, we find it reasonable to use Attachment A to Staff's revised comments as the basis of the ordered scope of study. We have modified Staff's Attachment A to reflect the proposed order on grandfathering issued concurrently recommendations from other parties, and responses from the Company.

ORDER

IT IS HEREBY ORDERED that Rocky Mountain Power conduct a study of on-site generation, the scope of which is identified by Attachment A hereto.

IT IS FURTHER ORDERED that parties continue to comply with Order No. 34602, issued March 17, 2020. All pleadings should be filed with the Commission electronically and shall be deemed timely filed when received by the Commission Secretary. See Rule 14.02. Service between parties should also be accomplished electronically. Voluminous discovery-related documents may be filed and served on CD-ROM or a USB flash drive.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 26th day of August 2020.

Paul Kjellander

PAUL KJELLANDER, PRESIDENT

Kristine Raper

KRISTINE RAPER, COMMISSIONER

Eric Anderson

ERIC ANDERSON, COMMISSIONER

ATTEST:

Jan Noriyuki

Jan Noriyuki
Commission Secretary

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Attachment A: Scope of Rocky Mountain Power's On-Site Generation Study

Netting Period

1. Calculate the class revenue requirement if each of the existing customer-generators netted their energy exports:
    a. Monthly
    b. Hourly
    c. Instantaneously
2. Calculate the total class export credit payments if each of the existing customer-generators net their energy exports:
    a. Monthly
    b. Hourly
    c. Instantaneously
3. Analyze bill impacts to existing customer-generators, stratified by usage, if energy exports are netted:
    a. Monthly
    b. Hourly
    c. Instantaneously

Export Credit Rate

Modeled Data as a Proxy for Actual Customer Export Data

4. Confirm when a full year of hourly AMI export data will be available for customer-generators.
5. Explain the Company's method for verifying and validating the accuracy of its model and modeled customer export data.

Avoided Energy Value

6. Calculate the avoided cost of exported energy using the energy price assumptions in the Company's most recently acknowledged Integrated Resource Plan ("IRP").
    a. Provide supporting documentation.
7. Provide the calculations and documentation showing why the avoided cost of exported energy produced by customer-generators should only be valued at 85% of the total avoided energy value.

Avoided Capacity Value

8. Analyze the capacity value of exported energy provided by customer-generators on a class basis using one of two methods:
    a. a Loss of Load Probability Study, or
    b. Determine the power that is reliably exported to the grid by net metering during peaking events. Use the top 100 peaking events from each of the past 10 years (1,000 peaking events). Use a reliability threshold of 99.5%. If, for example, the study determines that customer-generators provide no less than 1.5 MW of power during 99.5% of the peaking events, then use 1.5 MW as the basis for determining the capacity avoided by the customer-generator class.
9. Provide hourly time-differentiated capacity values.

Avoided Risk

10. Analyze whether there is a fuel price guarantee value provided by on-site generators as a class.

Project Eligibility Cap

11. Analyze the pros and cons of setting a customer's project eligibility cap according to a customer's demand as opposed to predetermined caps of 25 kW and 100 kW.
    a. Analyze at 100% of demand.
    b. Analyze at 125% of demand.

Avoided Transmission and Distribution Costs

12. Quantify the value of transmission and distribution costs that could be avoided by energy exported to the grid by net metering customers using the methodology for calculating the avoided transmission and distribution costs provided by energy efficiency programs.

Avoided Line Losses

13. Explain the avoided line loss calculations at a level that an average customer can understand.

Integration Costs

14. Study other methods for determining the integration costs of net metering customers as a class. Calculate the dollar impact of deferring a study of the integration charges for net metering customers until AMI data is available, and if different, calculate the dollar value of using a zero placeholder until AMI data is available.

Avoided Environmental Costs and Other Benefits

15. Quantify the potential value of grid stability, resiliency, and cybersecurity protection provided by on-site generators as a class and different penetration levels.
16. Quantify the value to local public health and safety from reduced local impacts of global warming such as reduced extreme temperatures, reduced snowpack variation, reduced wildfire risk, and other impacts that can have direct impacts on Rocky Mountain Power customers.
17. Quantify local economic benefits, including local job creation and increased economic activity in the immediate service territory.
18. Quantify the possible net value of Renewable Energy Credit sales produced by net metering exported energy.
19. Quantify the reduced risk from end-of-life disposal concerns for the Company compared to fossil-fueled resources.

Recovering Export Credit Rates in the ECAM

20. Explain the method currently used to record net metering bill credit costs.
21. Quantify the current annual amount of the net metering costs allocated to each class.
22. Present and explain how these costs have been allocated and recovered between rate classes for the past five years.
23. Quantify these annual costs under the assumptions that the Export Credit Rate is the retail rate, 7.4 cents/kWh, 5 cents/kWh, or 2.23 cents/kWh.
24. Analyze how these costs would be allocated and recovered by rate class through the Company's proposed ECAM method going forward.

Schedule 136 Implementation Issues

Billing Structure

25. Explain if and how seasonal and time-of-delivery price differences will be used to help align customer generated exported energy with the Company's system needs.
26. Explain if and how using more granular time periods for differentiating energy and capacity credits could be used to more closely align customer-generated exports with the Company's system needs.
27. Explain how potential customer-generators and on-site generation system installers will have accurate and adequate data and information to make informed choices about the economics of on-site generation systems over the expected life of the system.

28. Explain how on-site generation system installers will be able to comply with the Residential Solar Energy Disclosure Act if hourly or instantaneous netting and/or granular time-differentiated export rates are adopted and updated annually.

Export Credit Expiration

29. Quantify the magnitude, duration, and value of accumulated export credits as of August 1, 2020.
30. Quantify the impact to customers of a 2-year, 5-year, and 10-year expiration periods.
31. Explain the need for credits to expire.
    a. Show how the Company does or does not benefit from the expiration of customer export credits.
    b. Show how non net bill customers are harmed or benefited from the expiration of customers export credits.

Frequency of Export Credit Rate Updates

32. Quantify the impact of biennial updates as compared to annual updates of the Export Credit Rate by comparing the changes in the SAR energy rate, line losses, and integration costs using historical data over one year, one IRP cycle (two years), and two IRP cycles (four years).

<u>Smart Inverter Study</u>

33. Explain the key aspects of the Company's Utah smart inverter policy and quantify the benefits of applying that policy in its Idaho service territory, in particular, the potential benefits of reactive power control.