**Portland General Electric Company**
*121 SW Salmon Street • Portland, Oregon 97204*

January 14, 2010

***Via Electronic Filing and U.S. Mail***

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
PO Box 2148
Salem OR 97308-2148

**Re: AR 538 – RULEMAKING REGARDING SOLAR PHOTVOLTAIC ENERGY SYSTEMS (HB 3039)**

**UM 1452 – INVESTIGATION INTO PIOLET PROGRAMS TO DEMONSTRATE THE USE & EFFECTIVENESS OF VOLUMETRIC INCENTIVE RATES FOR SOLAR PHOTOVOLTAIC ENERGY SYSTEMS**

Attention Filing Center:

Enclosed for filing in AR 538 and UM 1452 are an original and one copy of:

Opening Comments of Portland General Electric Company

These documents are being filed by electronic mail with the Filing Center. An extra copy of the cover letter is enclosed. Please date stamp the extra copy(s) and return to me in the envelope provided.

These documents are being served separately upon the AR 358 and UM 1452 service lists.

Thank you in advance for your assistance.

Sincerely,

J. Richard George
Assistant General Counsel

**JRG:smc**
**Enclosures**
**cc: Service List-AR 538/UM 1452**

**BEFORE THE PUBLIC UTILITY COMMISSION**
**OF OREGON**
**AR 538/UM 1452**

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|---|---|
| In the Matter of<br><br>PUBLIC UTILITY COMMISSION OF OREGON<br><br>AR 538, In The Matter of Rulemaking Regarding Solar Photovoltaic Energy Systems (HB 3039)<br><br>UM 1452, In the Matter of Investigation into Pilot Programs to demonstrate the use and effectiveness of Volumetric Incentive Rates for Solar Photovoltaic Energy Systems. | **Comments of Portland General Electric Company** |

## INTRODUCTION

Portland General Electric Company ("PGE") appreciates the opportunity to provide comments on: 1) the draft Oregon Administrative Rules ("OAR") in the AR 538 Rulemaking, including Staff's December 4, 2009 Straw Proposal and 2) the UM 1452 Investigation, including Staff's December 19, 2009 Comments. Initially, we address the Federal Energy Regulatory Commission (FERC) jurisdictional issue raised by Staff in its December 19, 2009 Comments. Thereafter, our comments are generally organized under the topic categories as presented in the Staff's Straw Proposal, and we include proposed wording changes to the draft rules. Our comments discuss several key areas in the rules necessary to implement a solar photovoltaic (PV) Feed-in Tariff (FiT) pilot that achieves the objectives of House Bill 3039 (HB 3039) in an efficient and equitable manner.

HB 3039 requires that prior to April 1, 2010, the Public Utility Commission shall "establish a pilot program for each electric company to demonstrate the use and effectiveness of volumetric incentive rates and payments for electricity delivered from solar photovoltaic energy systems."[1] The Commission initiated a Rulemaking – Docket No. AR 538 – to establish the pilot program and FiT for photovoltaic energy systems based on HB 3039. The Commission also initiated an investigation into the pilot programs structure – Docket No. UM 1452 – which includes details about the volumetric Incentive Rate (VIR) and program operational standards. On December 18, 2009, simultaneous opening comments in Docket No. UM 1452 were suspended "indefinitely," while parties discussed FERC jurisdictional issues related to wholesale sales of energy. Staff issued its comments with potential solutions to those issues on December 19, 2009.

PGE has participated in the workshops held by OPUC staff. We have provided recommendations to the draft rules and how various aspects maybe successfully implemented. We provide herein more comments on the following issues.

- FERC Jurisdiction
- Pilot Program Expectations
- Rate Impact
- Cost Recovery
- FiT Interconnection Rules
- Capacity Allocation
- Qualified Third Parties
- Volumetric Incentive Rates

PGE's comments below include proposed changes to the draft rules. For convenience, our proposed wording changes to the OARs are noted in comments below

[1] While parties generally interpret this to mean the pilot program should be launched on April 1, 2010, the language allows for the Commission to have established the parameters of the program by April 1st. Utilities would implement at a subsequent date as ordered by the Commission.

and the actual redlined rules are consolidated to Attachment 1. We begin by commenting on the FERC jurisdictional issue.

**FERC JURISDICTIONAL ISSUE**

Staff, in comments filed December 19, 2009, flags an important question regarding whether payment of a VIR for the actual energy generated by participants in the pilot would be for FERC jurisdictional sales. If so, the pricing for such sales is governed by FERC and sellers need specific FERC authority to make such sales--either by being Qualified Facilities (QFs) under the Public Utility Regulatory Policies Act (PURPA) or through having market based rates. 16 U.S.C. 824-824m. PGE has reviewed the research provided and the conclusion reached by the Oregon DOJ on this matter, and agrees that likely, the participant sales would be FERC jurisdictional.

As FERC jurisdictional sales, the concern is that the OPUC cannot establish a volumetric payment rate that will properly facilitate participation in the pilot. This may or may not be true. For market based sales, the OPUC cannot establish the rates; however, for sales by QFs under PURPA, the Commission does have authority to establish the avoided cost pricing for such sales. PGE believes that it may be possible to establish avoided cost rates that are specifically adjusted pursuant to the factors enumerated by PURPA that would reflect the unique characteristics of solar participants in the pilot. See 18 CFR 292.304(e). When adjusted, these payments may be both a proper reflection of the resources avoided by the solar facilities, and adequate to facilitate such solar development. PGE notes, however that any adjustment to avoided cost for environmental attributes of a generator should only be made if the utility actually receives renewable energy credits representing such attributes.[2]

Staff's proposed solutions to the FERC jurisdictional issue are less clean. Staff proposes a new form of net metering under which the participants in the program would receive a VIR as a credit on generation. This credit would offset the customer's bill for its load, but also would greatly exceed the electricity rate paid by the customer-generator. It may not trigger FERC jurisdiction, because arguably there would be no net energy sent to the grid, as netting of energy produced and consumed would occur over a year period. However, because the credit amount may far exceed the customer-generator bill from the utility for its electrical load, it may still be considered a wholesale sale. PGE is uncertain how this work-around would be viewed by FERC and the courts, and thus is wary of the risk this uncertainty ultimately places on participants in the program and on the utility for rate stability and recovery. With the current uncertainty surrounding FERC jurisdiction, PGE requests that the Commission allow the FiT power purchase agreement to include a provision that allows the utility to recoup money from such participants should the sales be deemed FERC jurisdictional and the payment amount in excess of what is allowed by law. If the FERC jurisdictional issue is resolved to parties' satisfaction, the provision is moot.

With respect to the proposal for competitive bidding, PGE also has potential concerns as to how this would work to resolve the FERC jurisdictional issues and still meet the objectives of the program. Because this offered solution was not yet fully

[2] This may require facilities to register with the Western Renewable Energy Generation Information System (WREGIS) or work with an aggregator to provide RECs through WREGIS to the utility.

developed by Staff, PGE wishes to reserve its comments when more details have been provided.

Finally, some parties have suggested that any costs of VIR payments that are above avoided cost could simply reflect the environmental attributes associated with the generation. PGE believes this approach is not a good idea. Establishing an artificial above-market price for this commodity could cause market confusion and harm. It also may cause impacts and be discriminatory with respect to avoided costs for other non-FiT renewable projects.

**PILOT PROGRAM EXPECTATIONS**

Notwithstanding the FERC jurisdictional issues, a successful pilot should yield valuable information and insights into the best practices for solar PV development in the state. With such information, we hope to encourage a balancing of interests between participants and utility customers in achieving a sustainable approach to solar PV development.

We hope to learn about program features that are effective as well as other program attributes that are less effective. The pilot program may not be perfect on launch, but the rules allow adjustments. In some respects, the rules could provide more flexibility so that adjustments can be made when most needed. As new insights are realized, changes should be applied, as soon as practical, to capture improvements and facilitate participation levels. We should not set expectations at levels that will overextend the program, stress the utility's capabilities and run up costs unnecessarily.

We may also learn about program features that are a hindrance or overly burdensome. Therefore, the program should be implemented with a degree of care to allow it to develop in a manageable manner and with reasonable expectations. This will allow the program to respond to variables such as downward cost trends for equipment.

**RATE IMPACT**

PGE supports the proposed rule – OAR 860-083-0380(2) – that requires periodic forecasts by utilities of the rate impacts of the solar PV pilot program. PGE also supports the 0.25% rate impact limit in OAR 860-084-0380(3), which mirrors HB 3039 language.

PGE recommends that the Commission affirm its intent to adjust the FiT pilot's capacity limits (and VIR rates) when necessary to limit the rate impacts to the 0.25% target as much as reasonably possible. It is important that the Commission establish and modify the program parameters in a manner that considers the pilot program's cost impact on the utility's consumers, who are paying for this pilot program.

A Commission policy to consider rate impacts on an on-going basis is consistent with the goal of a pilot program—to assess the effectiveness of a solar FiT. The assurance by the Commission that the program costs will not cause rate changes that materially exceed the rate impact cap set by legislation lends credibility to the Commission's implementation of FiT pilot program.

For example, the VIR could be set at a high enough level that participation reaches the 0.25% rate impact relative to the utility's revenue requirement before reaching the cumulative nameplate capacity of 25 MW for the pilot. The rate impact language is permissive, which is appropriate for a pilot program. It recognizes that the costs of the pilot are uncertain, and thus setting cost recovery rate levels exactly right is impossible. Cost recovery rate impacts could exceed the 0.25% limit if the Commission does not adjust participation limits to the degree and in the timeframe necessary to avoid exceeding the rate impact limit. .

The rate cap language in HB 3039 establishes a target to manage the impact on utility ratepayers in recognition of the pilot nature of the program. The language recognizes that the costs of the pilot are uncertain, which means setting the correct cost recovery rates in advance is impractical. In addition, if costs are unchecked, future feed-in tariff programs may be imperiled and viewed as risky due to the potential for excessive costs.

**COST RECOVERY**

Proposed rule OAR 860-084-0390 reflects HB 3039 provisions which provide that utilities may request recovery from customers of all prudently incurred costs associated with implementing this program.[3] (PGE's proposed mechanism to recover program costs is explained in detail below.)

The proposed rule states:

> An electric company may request recovery of prudently incurred costs associated with compliance with the solar photovoltaic pilot program requirements. Mechanisms for recovery of cost associated with compliance will be established by Commission Order.

The rule establishes two processes that the Commission must implement. First, the cost recovery mechanism must provide a means that the utility can use to track and accumulate all prudently incurred pilot program costs, such as a balancing account. Second, the cost recovery mechanism will provide a method, such as a rate schedule, for the utility to implement or modify the pilot's cost recovery rates for eligible customer classes in timely manner.

[3] PGE supports the draft OAR 860-084-0380 language as providing appropriate direction for cost recovery.

In addition, the Commission must determine if certain retail electricity consumers are or are not eligible for participation in this pilot for setting recovery rates (HB 3039, Section 2, (10)). In particular, the Commission must decide whether retail electricity consumers receiving electricity service from energy service suppliers and/or served under multi-year cost of service rate opt-out arrangements are eligible for this pilot. On this issue, PGE suggests that direct access customers are "retail electricity consumers" and thus no customer class is excluded from potential participation. This consideration is also important in establishing the specific cost recovery provision, as explain below.

Proposed OAR 860-084-0380 specifies that each electric utility file estimates of the rate impact for each customer class of participation in its pilot program. Since all customer classes are eligible, PGE recommends a change to the second subsection of the proposed rule requiring utilities to file estimates of the rate impact for <u>each</u> customer class. Actual participation by a class should not preclude cost recovery. Cost recovery should be based on eligibility for the pilot, regardless of participation.

**Cost Recovery Mechanism**

HB 3039, Section 3(5) states,

> All costs prudently incurred by an electric company to comply with the solar photovoltaic generating capacity standard established by the section are recoverable in the company's rates and are eligible for an automatic adjustment clause established by the commission under ORS 469A.120.[4]

We reviewed various rate recovery methods including: modifying our existing Schedule 122 - Renewable Resource Automatic Adjustment Clause (RAC) to

[4] ORS 469A.120, Section 1 states, "...all prudently incurred costs associated with the compliance with a renewable portfolio standard are recoverable in the rates of an electric company, including interconnection costs, costs associated with using physical or financial assets to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs and other costs associated with transmission and delivery of qualifying electricity to retail electricity consumers." ORS 469A.120, Section 3, provides for an "...automatic adjustment clause as defined in ORS 757.210 or another method that allows timely recovery of costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission."

accommodate the FiT; a new supplemental adjustment rate schedule, which may be modeled after the RAC; and our existing Schedule 105 – Regulatory Adjustments for a limited time period. Although various approaches are possible, PGE proposes that the Commission allow pilot program cost recovery in a direct, simple and timely manner.[5] Below we propose a cost recovery mechanism that is similar to the RAC, is an automatic adjustment clause, can track program costs, and includes all customer groups.

**Incremental Pilot Program Costs**

For FiT pilot program cost recovery, PGE will file a summary of all start-up and on-going incremental pilot program costs including, but not limited to, costs in the following activity areas:

- The total VIR payment amounts made to FiT participants
- Administrative costs associated with FiT program operations
    - Applicant/participant support and information services
    - Application processing, agreements, billing management
    - Distribution system impact reviews, installation inspections
- Data collection, customer surveys
- Required FERC and other regulatory reporting requirements.

**Revised Schedule 105**

We propose for convenience that Schedule 105, Regulatory Adjustments, be modified to include FiT cost recovery from all customer classes. Specifically, Schedule 105 would include a subsection setting forth rates by rate schedule for the FiT. Further,

[5] The specific mechanisms in this proposal are in part dependent on findings by the Commission regarding the extent and responsibilities of the utility to cover interconnection costs for projects and requirements (and cost impacts) associated with responding to an unexpectedly large influx of reservation applications.

the FiT component of Schedule 105 would be approved as an "automatic adjustment clause" as defined in ORS 757.210.[6] A new FiT cost recovery supplemental adjustment schedule could be filed in the alternative with the same procedures and designation as an "automatic adjustment clause" as proposed for Schedule 105.

The FiT Schedule 105 cost recovery mechanism would operate as follows:

- First, in March of this year, PGE will file a revised Schedule 105 (or new schedule if required by the Commission) to establish the accounting for FiT-related incremental costs incurred during 2010. Initially, the FiT recovery rate will be set to zero.
- In November, 2010, PGE will file a revision to Schedule 105 rates (which are set for each class of customer) to recover 2010 FiT costs beginning January 1, 2011. PGE, with Commission approval, could also forecast incremental FiT costs incurred in 2011 and incorporate such amounts into the 2011 Schedule 105 rates.
- This process would be repeated annually through the end of the initial phase of the pilot in March 2015.
- After March 2015, FiT costs should be fairly stable (primarily the FiT payments to participants) and could be included in general rates.

The annually updated Schedule 105 approach allows for consistent recovery of FiT costs. By resetting the Schedule 105 rate each year for FiT costs, any over or under-recovery due to actual versus expected costs and participation variances can be reflected

[6] The "automatic adjustment clause" provides a means to update the FiT cost recovery rates without prior hearing; any rate changes are subject to Commission review and approval. An automatic adjustment clause is appropriate given the narrow set of costs to be recovered, and similarity of these costs to other renewable costs recovered through Schedule 122, Renewable Resources Automatic Adjustment Clause.

in the next year's adjusted Schedule 105 rate. In addition, revising Schedule 105 eliminates the need for an additional schedule.

**Other Cost Recovery Considerations**

PGE assumes, for cost recovery purposes, that direct access customers are eligible to participate in the FiT pilot program and direct access customers should be included in the customer classes paying for FiT costs. Consequently, cost recovery through the existing Schedule 122, Renewable Resource Adjustment Clause is not appropriate given the mismatch of eligibility to participate in the program and the exclusion from cost recovery.

**Power Supply Impacts**

PGE also proposes that the pilot program generation and costs not be included in the annual power cost update process. The absolute quantity of MWh produced from the solar PV pilot program as a portion of the total PGE system power requirements will not a have material impact on power supply forecasts, costs or planning. Therefore, in the interests of simplified program management, we propose that the MWh output be tracked for payment and reporting purposes, but not be required to be modeled in forecasting power costs (for PGE, this modeling is through the Monet power cost model).

PGE's forecast of total customer load in 2010 is about 19 million MWh. Estimated output for PGE's allocated share of the 25 MW program capacity is about 15,000 MWh or about 0.08% of the total load. The initial program year's output is likely to be even less. The modest level of output from the FiT pilot coupled with the uncertainty of forecasts further supports using Schedule 105 to recover program costs in a direct and simple manner.

**FiT INTERCONNECTION RULES**

Interconnection costs represent the costs that the utility will incur to install or modify an existing service lateral to accommodate a new FiT meter base and connection to the PGE distribution system. PGE's comments regarding interconnection requirements pertain to two elements that the Commission needs to address to provide direction to utilities and participants:

- Several modest draft rule language changes are needed to guide the physical interconnections of the solar PV project to the utility's distribution system.
- Draft rule changes are needed regarding cost responsibility for the utility-side interconnection facility costs.

The OAR Division 39 Net Metering Rules were substantially adopted in the draft rules for solar FiT interconnections set forth in sections 310 through 350. PGE supports the general adoption of the net metering interconnections rules with certain changes briefly noted below.

- OAR 860-084-0330 (4), 4(a) and 4(b) have cross references to OAR 860-084-0290, which may need to be modified to 0280 or removed.
- In OAR 860-084-0330 (4)(b) and (4)(c) the paragraph begins with "The eligible system may be safely interconnected," which is unclear and should be deleted.
- OAR 860-084-0330 (4)(c) states, "the applicant may request a binding estimate of the cost of those facilities…" PGE proposes using the same language provided in the Net Metering rules, which states, "a non-binding, good-faith estimate."

- PGE recommends incorporating the language from the net metering rules (OAR 860-039-0015) regarding disconnects, specifically including (1), (2), (E)(b), and (3) into OAR 860-084-0340. This language is important for safety purposes.

**Interconnection Cost Responsibility**

PGE proposes revising language for draft rule OAR 860-084-0280 Interconnection Cost Responsibilities and deleting OAR 860-084-0290 Reasonable Costs. PGE proposes the interconnection rules be consistent with other programs --under PGE's qualifying facility agreements and in other jurisdictions with a FiT, the customer pays all utility-side interconnection costs. A standard interconnection facilities cost allowance should be a single amount applicable to all solar PV projects and reflect the interconnection of the smaller scale projects to the PGE system.

PGE considered two options related to interconnection facilities cost responsibility. Both of the options "enable the development of the most efficient solar voltaic energy systems." (HB 3039, Section 2 (3))

- Under the first option the participant pays any utility-incurred interconnection costs directly.
- The second option is a fixed interconnection facilities installation cost allowance.

Under either approach, a clear interconnection cost responsibility standard is established and interconnection facilities costs are primarily the solar project's responsibility. The potentially wide range of interconnection situations and wide range of costs warrants such a simple standard. Further, with solar PV projects retaining the interconnection cost responsibility, the draft rule at 860-84-0290, Reasonable Costs can be eliminated because there is no need to determine reasonable costs for each interconnection.

The first option supports cost effective projects, with the basic interconnection costs included in the VIR. The customer is responsible for all interconnection costs. Because this option provides administrative simplicity, PGE recommends this approach.

The second option, a standard interconnection facilities cost allowance, provides participants with a standardized "up to" amount the utility will incur for the interconnection of the solar PV installation. The customer is responsible for all interconnection costs over the allowance. The allowance approach requires additional administrative process.

Under either option, the location of the solar PV meter will need to be adjacent to the existing meter for the smaller scale installations. As a general rule, smaller solar PV units with kW capacity similar to the peak load of the host site will not require extensive changes to the distribution system, limiting the interconnection costs to adding appropriate utility-side wiring to the solar PV meter.

Larger solar PV projects will require a much more detailed review for interconnections as outlined in the Level 1, 2 and 3 interconnection review rules. For the larger projects the cost of the interconnection depends on circumstances such as the location, existing distribution infrastructure, capacity of transformer, other solar projects on the distribution feeder, and other factors. Further, the interconnection costs are most likely a small proportion of the total solar PV project costs. Given the potential for more unique interconnection requirements of the larger projects and the variability of costs among projects, PGE discourages differing allowances based on project size.

In opening comments filed on December 18, 2009, Industrial Customers of the Northwest (ICNU) stated, "The proposed rules depart from convention, however, in assigning virtually all interconnection costs responsibility to participating electric companies...interconnection cost responsibility is primarily borne by the customer in all other interconnections, such as small generator, net metering, and qualifying facility interconnections."(p.2) PGE agrees with ICNU that this assignment of all interconnection cost responsibility to the utilities in the proposed rule (OAR 860-084-380(3)) will hinder a legislative purpose behind HB 3039 and cost responsibility should conform to established Commission standards.

**CAPACITY ALLOCATION**

In the Straw Proposal for UM 1452, Staff asserts that no Commission decision is necessary relating to the Solar Capacity Standard, but Staff does establish the exact MW requirements for each utility in the rule. PGE disagrees with this computation of the capacity allocation between utilities.

HB 3039, Section 3 (2) states,

> For the purpose of complying with the solar photovoltaic generating capacity standard established by this section, on or before January 1, 2020, each electric company is required to maintain a minimum generating capacity from qualifying systems. The minimum generating capacity for each electric company is determined by multiplying 20 megawatts by a fraction equal to the electric company's share of all **retail electricity sales** made in this state in 2008 by all electric companies.

Staff has interpreted "retail electricity sales" to mean utility revenues. PGE interprets "retail electricity sales" to mean MWh sales. The phrase "share of all retail electricity sales" is more appropriately interpreted as the proportion of power consumed by retail electricity consumers. Therefore, the percent of solar generation by each utility is more appropriately tied to amount of energy used in each utility's service territory. Furthermore, RPS requirements from SB 838 are based on MWh sales rather than revenue. PGE recommends changes to proposed OAR 860-048-0020 Solar Photovoltaic Capacity Standard to reflect this allocation method.

Staff further carries this allocation over to the FiT pilot, although there is no provision in HB 3039 for allocating the 25MW in the pilot between utilities. PGE believes the 0.25% rate cap is intended to act as a means to limit the impact to customers of any one utility. For purposes of the pilot, the Commission should carefully manage the pilot's rate impacts and the use of capacity allocation as a tool to manage the pilot's participation rates to levels manageable by the utilities.

**DEFINITIONS**

**Qualified Third Parties**

HB 3039, Section 3 (4) states,

> An electric company may satisfy the solar photovoltaic generating capacity standard established by this section with solar photovoltaic energy systems owned by the company or with contracts for the purchase of electricity from qualifying systems.

HB 3039's definition of "Qualified Third Parties" does not preclude an electric company or its affiliates from qualifying third party status. However, the proposed definition in OAR 860-084-0010(11) for "Qualified Third Parties" expressly precludes an electric company or its affiliates from qualifying third party status.[7] PGE proposes the rule mirror the broad definition as contained in HB 3039. We are not aware of the

[7] The proposed rule states, "An electric company or its affiliate is not a qualifying third party."

reasoning for the additional restriction added to the proposed rule. During the workshop phase, PGE provided written comments recommending affiliates to qualify as a third party.

Prohibiting the utility or its affiliates as a qualifying third party may actually inhibit larger projects similar to the Sunway 1[8] (104 kW ODOT Solar Project) and Sunway 2 (1.1 MW Prologis Solar Project) without good cause. Docket No. UE 209, PGE Exhibit 200, pages 15-20 describes the third-party financing arrangements and ownership structure for these projects in greater detail.

**VOLUMETRIC INCENTIVE RATE DETERMINATION**

In Staff's Straw Proposal filed on December 4, 2009, Staff proposed the initial incentive rate to be approved by the Commission. If the Commission decides to set the VIR, the rule allows for a rate adjustment over the pilot program time frame and through a public process. PGE agrees that this is a useful process for the pilot program.

PGE proposes a VIR level based on a value equivalent to current tax credit and rebate incentives (that, per HB 3039, are foregone if a solar PV unit owner elects to participate in the VIR as the alternative). Matching incentives means matching the current incentives available to solar Net Metering or QF customers in Oregon minus incentives available under this VIR pilot. As explained below, a VIR that is similar to the current value of the existing state incentives will provide a good foundation for the pilot to develop in the future.

As the Commission considers VIR levels, the status of current incentives under Net Metering are instructive. Net Metering activity in PGE's service territory was very high in 2009, despite the challenging economy. Customers added 4.19 MW of capacity

[8] Sunway 1 is subject to a net metering agreement.

in 2009 from 274 new installations. In December alone, 1.58 MW of system capacity went online. For perspective, PGE's Net Metering entered 2009 with a program total of 4.4 MW. Further, 83% of the Net Metering application received in 2009 were from residential customers. Activity levels like these tell us that the current incentives are working and supports PGE's proposal to base the VIR on the equivalent value of current incentives.

With this solar Net Metering history as a backdrop to establishing the VIR, the Commission needs to consider the implications for VIR levels. We note that a VIR that is substantially higher in value than current incentives may well supplant the Net Metering activity levels (at least until capacity limits are reached).

**Geographic Rate Differentiation**

Staff, in their Straw Proposal, has proposed geographically differentiated rates. The differentiation stems from the use of a forced 15-year payback and varying solar output levels. One of the theories is that due to differing capacity factors throughout the state, more energy may be produced in some areas and less in others. Therefore, areas with more sun require a lower rate to achieve a 15-year payback than areas with less sun.

PGE proposes that differentiated solar PV rates are not appropriate or useful and not required by HB 3039. Geographic rate differentiation appears to be based on an assumption that solar PV projects will be installed under ideal solar conditions that maximize output in every instance. We believe there is a great deal of value in a pilot program where solar PV units may be installed under differing conditions. Given that unit installation costs are not likely to vary greatly by location, we believe a solar PV unit in Crook or Deschutes County should be eligible for the same rate as a unit that happens to be located in Multnomah County. If a Crook County unit is not located in an ideal solar location, but is expected to produce the same kWh output as a Portland area unit, we are not aware of a valid reason for the geographic price reduction and attendant loss of information about the incentive of solar PV development.

PGE supports VIR differentiation based on project size because HB 3039 directs utilities to purchase 75% of the FiT energy from smaller projects. There are cost differences between smaller and larger projects that benefit large projects. Geographically, however, cost differences do not exist. PGE therefore recommends, for a particular project size, a single volumetric incentive rate for the entire state.

**Method of Calculation/Results**

PGE proposes that, to establish the VIR, the Commission use a standard, existing model to establish rates. The Solar Advisor Model provided by National Renewable Energy Laboratory (NREL) referenced at the January 6, 2010 workshop is a detailed and complete model that PGE used for its VIR analysis.

PGE ran scenarios using the NREL model, all of which use a 15-year analysis, using (1) the matching incentive method described previously and (2) the cost based method. It is important to note that the assumptions and inputs used greatly affect the results, regardless of the model used. PGE discusses the assumptions used later in this section. Results are shown in the table below.

**Table A**

| | **Matching Incentive VIR (cents/kWh)** | **Cost Based VIR (cents/kWh)** |
|---|---|---|
| Residential 0 to 10 kW (4 kW sample) | 23.37 | 48.83 |
| Business 0 to 10 kW (4 kW sample) | 24.43 | 38.77 |
| Business >10 to 100 kW (199 kW sample) | 33.21 | 18.65 |

The cost based VIR calculation entails entering all assumptions and inputs into the Solar Advisor Model, then running the simulation. The VIR is the LCOE(nom), or the nominal levelized cost of energy. The model provides both a real and nominal LCOE. The nominal LCOE is appropriate if there are no adjustments to the VIR over the life of the 15 year agreement.

The matching incentives VIR requires setting up two cases for a given project. The first case involves running the analysis for a Net Metering project with all available incentives, including state tax credits and ETO incentives. Each project has a net present value as calculated by the Solar Advisor Model. A second case is set up with all the same assumptions and inputs as the Net Metering project, with the exception of state tax credits and ETO incentives, which are not available to projects eligible for the VIR. A production based incentive ($/kWh) is then entered into the model, based on a 15 year term. The goal is to make the net present value of the second case equal to that of the first case. The value of the production based incentive is then added to the utility rate charged to the customer in the first case under net metering. The sum provides a VIR based on matching incentives.

There are two 0-10 kW prices in Table A, above. These highlight the differences in incentives between residential and business customers. Business customers are able to use MACRS depreciation, whereas residential customer cannot. The differences under a cost based VIR between business and residential customers are especially apparent, with more than a 10 cent separation, for the same system size.

In this analysis, the incentives offered to business customers under Net Metering offer a significantly better payback period than 15 years. With a cost-based VIR established using a 15-year payback, Net Metering is more attractive. This is due to significant state incentives and the ability to use MACRS depreciation for tax purposes. PGE acknowledges that basing the VIR for these customers on matching incentives could be problematic. The per unit cost of large systems is less. However, due to attractive incentives available to business customers, the matching incentive VIR is higher for a business than a residential customer. On a per unit basis, the incentives for business Net Metering customers are more attractive.

**Assumptions and Inputs**

As stated previously, the assumptions and inputs used in the Solar Advisor Model have a profound affect on the results. PGE applied realistic inputs in the model.

- PGE used a 15-year analysis, along with a 15-year loan.
- The loan rate used is 7%, a mortgage in the residential cases.
- The location for all cases is Portland, Oregon. This yields a lower capacity factor than most other parts of Oregon.
- The inflation rate is 2.5% with a real discount rate of 5.5%, for a total discount rate of 8%.
- In all cases, insurance costs are zero as well as property taxes. The draft rules do not require insurance and PV systems in Oregon are exempt from property taxes.
- System degradation is 1% per year.
- The DC to AC derate factor is 0.77, which is the average suggested by NREL and confirmed as within a realistic range based on PGE's own

experience in Portland (77-80%). The tilt is 30 degrees, which the ETO uses as a default in their estimation calculator.

For the residential 4 kW system,

- PGE used a utility rate of 9.745 cents per kWh.
- A marginal federal tax rate of 35% and state tax rate of 9% is used.
- The system cost is $29,360 yielding $7.34 per watt DC. This includes $1,000 for interconnection.
- The module cost is $2.84 per watt DC, above the average of $2.70, the lowest mono-crystalline module price reported by www.SolarBuzz.com in their January 2010 Retail Price Survey (the lowest multi-crystalline price module price reported is $1.98). The inverter price used is $0.60 per watt AC. Both module and inverter costs from www.beyondoilsolar.com are provided in Attachment 2.
- The inverter price used reflects the median cost from this price list. All other costs including planning, installation, and additional material are $14,600.

The business 4 kW system,

- assumes a utility rate of 7.93 cents per kWh.
- A marginal federal tax rate of 35% and state tax rate of 6.6% is used.
- All other assumptions are equal to the residential case above.

The business 199 kW system also assumes,

- A utility rate of 7.93 cents per kWh.
- A marginal federal tax rate of 35% and state tax rate of 6.6%.

- The system cost is $1,294,750 yielding $6.51 per watt DC.

In all cases, the inputs used yield an 11.9% capacity factor. This is on the low end of capacity factor estimates for the Portland area. The Company has used assumptions that imply the rates listed in Table A are on the high end of estimates. PGE recommends rates approved by the Commission should be no higher than those listed in Table A.

**CONCLUSION**

PGE appreciates the diligent efforts of Staff and the parties in this docket to develop a pilot program for solar PV volumetric incentive rates. While we believe there may be a significant issue concerning FERC jurisdiction over the power purchased from potential FiT customers, we hope appropriate resolutions and certainty can be obtained to enable the pilot to be successfully implemented. As such, we have provided general comments on the Staff straw proposal and the proposed rules, including for important issues such as the VIR rate, cost recovery, and interconnection costs. We hope the Commission will consider such suggestions as we continue to work to implement HB 3039 by its April 1, 2010 deadline.

DATED, this 14th day of January, 2010.

Respectfully Submitted,

J. RICHARD GEORGE, OSB No. 97469
Portland General Electric Company
121 SW Salmon Street, 1WTC1300
Portland, OR 97204
Telephone: 503-464-7611
Fax: 503-464-2200
E-Mail: richard.george@pgn.com

## PGE Proposed Changes to Draft Rules

**860-084-0010**
**Definitions for Solar Photovoltaic Capacity Standard and Pilot Programs**

(11) "Qualifying third party" or "third party" means third party authorized, by the retail electricity consumer, to be assigned payments by the electric company under the standard contract. Qualifying third parties include, but are not limited to:

**Deleted:** An electric company or its affiliate is not a qualifying third party.

(a) A lender providing up front financing to a retail electricity consumer,

(b) A company or individual who enters into a financial agreement with a retail electricity consumer to own and operate a solar photovoltaic energy system on behalf of the retail electricity consumer in return for compensation,

(c) A company or individual who contracts with the retail electricity consumer to locate a solar photovoltaic system on property owned by the retail electricity consumer, or

(d) Any party identified by the retail electricity consumer to receive payments that the electric company is obligated to pay to the retail electricity consumer.

**860-084-0020**
**Solar Photovoltaic Capacity Standard**

On or before January 1, 2020, each electric company must own, or contract to purchase the capacity and output of, qualifying solar photovoltaic energy systems to achieve, or exceed, the following minimum solar photovoltaic capacity standards:

(1) Portland General Electric: 10.9 megawatts
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(2) Pacific Power: 8.7 megawatts
**Deleted:** 7.9

(3) Idaho Power Company: 0.4 megawatts
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Stat Auth: 2009 OR Laws Ch. 748
Stats. Implemented: 2009 OR Laws Ch. 748
Hist: NEW

**860-084-0280**
**Interconnection Cost Responsibility**

(1) For a Level 1 interconnection review, the electric company may not charge any fees, unless otherwise directed by the Commission.

(2) For a Level 2 or Level 3 interconnection review, the electric company may charge an application fee, as established by Commission order. If an interconnection request is denied by the electric company, this fee must be refunded to the applicant.

(3) All costs associated with required additions or modifications to the electric company's interconnection facilities (including the meter), modifications to the electric distribution system, interconnection reviews, or system upgrades are the responsibility of the Eligible participant.

(a) Interconnected systems must be equipped with metering equipment that can measure the flow of electricity in both directions and comply with ANSI C12.1 standards and OAR 860-023-0015. The electric company determines the location of the meter.

(b) The electric company constructs, owns, operates, and maintains the meter and applicable interconnection facilities on the company side of the meter.

(c) The retail electricity consumer is responsible for the costs of connection between the eligible system and the meter.

(5) An Eligible Participant who is reinstalling a contracted system, and is eligible to continue in the solar photovoltaic pilot program under an existing standard contract, must pay the expense of the meter, interconnection facilities, required additions or modifications to the electric distribution system, interconnection review, or system upgrades in the new location as applicable.

Stat Auth: 2009 OR Laws Ch. 748
Stats. Implemented: 2009 OR Laws Ch. 748
Hist: NEW

## 860-084-0330
## Level 3 System Interconnection Review

(1) The electric company must apply the Level 3 review procedure for an application to interconnect an eligible system that meets the following criteria:

(a) The facility has a capacity of 500 kilowatts or less; and

(b) The facility does not qualify or failed to meet Level 2 interconnection review procedures.

(2) Following receipt of a Level 3 application and within three business days of a request from the applicant, the electric company must provide pertinent information to the applicant, such as the available fault current at the proposed interconnection location, the existing peak loading on the lines in the general vicinity of the eligible system, and the configuration of the distribution lines at the proposed point of common coupling.

(3) Within seven business days after receiving a complete application for Level 3 interconnection review, the electric company must conduct an impact study which includes a good faith cost estimate for determination of whether the electric company costs comply with the Reasonable Cost standard, as defined in OAR 860-084-. The impact study will be conducted in accordance with good utility practice

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**Deleted:** chooses the location of the meter and

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**Deleted:** retail electricity consumer

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**Reasonable Costs¶**
(1) The electric company may deny an interconnection application that exceeds a reasonable cost standard, as given in section (2) of this rule. ¶
(2) Each electric company must file, as part of periodic updates to the Commission, a list of interconnection requests that are denied. This list must include name and billing address of retail electricity consumer and intended installation address and interconnection location.¶
(3) The Commission will, by Order, establish a "reasonable cost" standard to limit the costs associated with the costs of interconnection review, installation, additional interconnection facilities, minor modifications, and system upgrades that are borne by the electric company in the installation of a solar photovoltaic energy system under this pilot program. Before applying the reasonable cost standard, the electric company must determine that the identified electrical system changes or upgrades would not be performed by the electric company in the normal operation and maintenance of its system or in compliance with other Commission Order. ¶
(4) The Commission will, by Order, establish the processes that an applicant may follow to complete installation of the system denied. These processes may include, but will not be limited to, ... [1]

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and must:

(a) Detail the impacts to the electric distribution system that would result if the eligible system were interconnected without modifications to either the eligible system or to the electric distribution system;

(b) Identify any modifications to the electric company's electric distribution system that would be necessary to accommodate the proposed interconnection; and

(c) Focus on power flows and utility protective devices, including control requirements; and

(d) Include the following elements, as applicable:

(A) A load flow study;

(B) A short-circuit study;

(C) A circuit protection and coordination study;

(D) The impact on the operation of the electric distribution system;

(E) A stability study, along with the conditions that would justify including this element in the impact study;

(F) A voltage collapse study, along with the conditions that would justify including this element in the impact study.

(4) After the applicant executes the impact study agreement and pays the electric company the amount of the good faith estimate, the electric company will complete the impact study and will notify the applicant within 30 calendar days of one of the following results:

(a) Only minor modifications to the electric company's electric distribution system are necessary to accommodate interconnection. In such a case, the electric company will approve the application and send the applicant an interconnection agreement; or

(b) Substantial modifications to the electric company's electric distribution system are necessary to accommodate the proposed interconnection, and the costs associated with the substantial modifications meet the criteria as defined in OAR 860-084-. In such a case, the electric company will approve the application and send the applicant an interconnection agreement; or

(c) Substantial modification to the company's electric system are necessary to accommodate the proposed interconnection, and the interconnection costs exceed the reasonable cost standard defined in OAR 860-084-0280. In such a case, the applicant may request non-binding, good-faith estimate of the cost of those facilities that is above the reasonable cost standard and of the estimated time required to build and install those facilities. The applicant must pay the cost of the interconnection facilities above the installation cost allowance and request the approval of the interconnection application. In addition, the electric company must offer to conduct, at the applicant's expense, an interconnection facilities study that must identify the types and cost of equipment needed to safely interconnect the applicant's facility.

(5) If the proposed interconnection may affect electric transmission or delivery systems other than those controlled by the electric company, operators of those other systems may require additional studies to determine the potential impact of the interconnection on those systems. If such additional studies are required, the electric company must coordinate the studies but is not responsible for their

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timing.

(6) If an applicant requests a facilities study under subsection (4)(b), the electric company must provide an interconnection facilities study agreement. The interconnection facilities study agreement must describe the work to be undertaken in the interconnection facilities study and must include a non-binding, good faith estimate of the cost to the applicant for completion of the study. Upon execution by the applicant of the interconnection facilities study agreement, the electric company will conduct an interconnection facilities study to identify the facilities necessary to safely interconnect the eligible system with the electric company's electric distribution system, and if the costs associated with this interconnection exceed the reasonable cost standard defined in OAR 860-084-, to propose a non-binding, good faith estimate of the cost of those facilities and the time required to build and install those facilities.

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(7) Upon completion of an interconnection facilities study, the electric company must provide the applicant with the results of the study and an executable interconnection agreement. The agreement must list the conditions and facilities necessary for the eligible system to safely interconnect with the electric company's electric distribution system.

(8) If the applicant wishes to interconnect, it must execute the interconnection agreement and return it to the electric company at least 10 business days prior to starting operation of the eligible system, unless the electric company does not so require.

(9) If the applicant wishes to interconnect under the terms of a reasonable costs exception, the applicant must pay a deposit of not more than 50 percent of the estimated cost of the facilities identified in the interconnection facilities study, complete installation of the eligible system, and agree to pay the electric company the actual installed cost of the facilities needed to interconnect as identified in the interconnection facilities study.

(10) Within 15 business days after notice from the applicant that the eligible system has been installed, the electric company will inspect the eligible system and will arrange to witness any commissioning tests required under IEEE standards. The electric company and the applicant will select a date by mutual agreement for the electric company to witness commissioning tests.

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(11) If the eligible system satisfactorily passes required commissioning tests, if any, the electric company must notify the applicant in writing, within three business days after the tests, of one of the following:

(a) The interconnection is approved and the eligible system may begin operation; or

(b) The interconnection facilities study identified necessary construction that has not been completed, the date upon which the construction must be completed, and the date when the eligible system may begin operation.

(12) If the commissioning tests are not satisfactory, the applicant must repair or replace the unsatisfactory equipment to reschedule a commissioning test.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748
Hist: NEW

**860-084-0340**

**Installation, Operation, Maintenance, and Testing of Contracted Systems**

A contracted system must install and maintain a manual disconnect switch that will disconnect the solar photovoltaic energy system from the electric company's system.

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(1) The disconnect switch must be a lockable, load-break switch that plainly indicates whether it is in the open or closed position.

(2) The disconnect switch must be readily accessible to the electric company at all times and located within 10 feet of the electric company' meter.

(3) The electric company must install the required disconnect switch at the electric company's expense.

(a) For customer services of 600 volts or less, an electric company may not require a disconnect switch for an eligible system that is inverter-based with a maximum rating as shown below.

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(A) Service type: 240 Volts, Single-phase, 3 Wire—Maximum size 7.2 kilowatts

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(B) Service type: 120/208 Volts, 3-Phase, 4 Wire—Maximum size 10.5 kilowatts

**Deleted:** b

(C) Service type: 120/240 Volts, 3-Phase 4 Wire—Maximum size 12.5 kilowatts

**Deleted:** c

(D) Service type: 277/480, 3-Phase, 4 Wire—Maximum size 25.0 kilowatts

**Deleted:** d

(E) For other service types, the eligible system must not impact the retail electric consumers' service conductors by more than 30 amperes.

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(b) The disconnect switch may be located more than 10 feet from the electric company meter if permanent instructions are posted at the meter indicating the precise location of the disconnect switch. The electric company must approve the location of the disconnect switch prior to the installation of the net metering facility.

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(3) The customer-generator's electric service may be disconnected by the electric company entirely if the solar facility must be physically disconnected for any reason.

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Stat Auth: 2009 OR Laws Ch. 748
Stats. Implemented: 2009 OR Laws Ch. 748
Hist: NEW

**860-084-0350**

**Requirements after Approval of a Solar Photovoltaic Interconnection**

(1) Once a contracted system has been approved under these solar photovoltaic interconnection

rules, the electric company may not require a retail electric consumer to test or perform maintenance on its facility except for:

(a) An annual test in which the contracted system is disconnected from the electric company's equipment to ensure that the inverter stops delivering power to the grid;

(b) Any manufacturer-recommended testing or maintenance;

(c) Any post-installation testing necessary to ensure compliance with IEEE standards or to ensure safety; and

(d) Testing required if the retail electric customer replaces a major equipment component that is different from the originally installed model.

(2) When a contracted system undergoes maintenance or testing in accordance with the requirements of these solar photovoltaic interconnection rules, the retail electric consumer must retain written records for seven years documenting the maintenance and the results of testing.

(3) An electric company has the right to inspect a retail electric consumer's facility after interconnection approval is granted, at reasonable hours and with reasonable prior notice to the retail electric consumer. If the electric company discovers that the contracted system is not in compliance with the requirements of these solar photovoltaic interconnection rules, the electric company may require the retail electric consumer to disconnect the contracted system until compliance is achieved.

Stat Auth: 2009 OR Laws Ch. 748
Stats. Implemented: 2009 OR Laws Ch. 748
Hist: NEW

**860-084-0380**
**Cost Recovery and Rate Impacts**

(1) An electric company may recover in rates all costs prudently incurred to offer the pilot program established under these rules, including, but not limited to, costs not otherwise reflected in rates for electricity usage related to:

(a) Payments for the output of contracted systems,

(b) Interconnection studies and related system modifications and upgrades, and

(c) Data collection and analysis for assessment of the company's pilot program.

(2) On July 1 of 2010, 2012, and 2014, and as otherwise directed by the Commission, each electric company must file for review in a Commission proceeding its estimates of the rate impact for each customer class, along with supporting work papers.

**Deleted:** of participation in its pilot program

(3) The Commission may establish total generator nameplate capacity limits for an electric company so that the rate impact of the pilot program for any customer class does not exceed 0.25 percent of the company's revenue requirement for the class in any year.

Stat Auth: 2009 OR Laws Ch. 748
Stats. Implemented: 2009 OR Laws Ch. 748
Hist: NEW

**860-084-0290**

**Reasonable Costs**

(1) The electric company may deny an interconnection application that exceeds a reasonable cost standard, as given in section (2) of this rule.

(2) Each electric company must file, as part of periodic updates to the Commission, a list of interconnection requests that are denied. This list must include name and billing address of retail electricity consumer and intended installation address and interconnection location.

(3) The Commission will, by Order, establish a "reasonable cost" standard to limit the costs associated with the costs of interconnection review, installation, additional interconnection facilities, minor modifications, and system upgrades that are borne by the electric company in the installation of a solar photovoltaic energy system under this pilot program. Before applying the reasonable cost standard, the electric company must determine that the identified electrical system changes or upgrades would not be performed by the electric company in the normal operation and maintenance of its system or in compliance with other Commission Order.

(4) The Commission will, by Order, establish the processes that an applicant may follow to complete installation of the system denied. These processes may include, but will not be limited to, processes whereby the applicant may choose to pay the difference between estimated and reasonable costs.

Stat Auth: 2009 OR Laws Ch. 748
Stats. Implemented: 2009 OR Laws Ch. 748
Hist: NEW

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Opening Comments of PGE
PGE Attachment 2
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# Inverter Pricing and Information

Inverters change direct current (DC) to alternating current (AC). Stand alone inverters can be used to convert DC, from a battery, to AC to run electronic equipment, motors, appliances, etc. Grid intertie inverters are used to convert the DC output of a photovoltaic module, a wind generator or a fuel cell to AC power that has the same phase angle as your electrical supplier. The energy goes back into your utility grid and your meter credits you with the amount of electricity you produce. Multifunction inverters perform both functions.

| Inverter Manuf. | Model | Wattage | Charger? | Grid Intertie? | Battery Backup? | List (US $) | Our Price (US $) |
|---|---|---|---|---|---|---|---|
| Fronius IG | Fronius 2000 | 2500 | No | Yes | No | ~~2375~~ | 1509.00 |
| | Fronius 3000 | 3500 | No | Yes | No | ~~2640~~ | 1677.00 |
| | Fronius 2500-LV | 3000 | No | Yes | No | ~~2479~~ | 1575.00 |
| | Fronius 4000 | 4600 | No | Yes | No | ~~3848~~ | 2445.00 |
| | Fronius 4500-LV | 4500 | No | Yes | No | ~~4010~~ | 2548.00 |
| | Fronius 5100 | 5300 | No | Yes | No | ~~4190~~ | 2662.00 |
| Fronius IG Plus | Fronius IG Plus 3.0 | 3000 | No | Yes | No | ~~3255~~ | 2112.62 |
| | Fronius IG Plus 3.8 | 3800 | No | Yes | No | ~~3850~~ | 2498.80 |
| | Fronius IG Plus 5.0 | 5000 | No | Yes | No | ~~5375~~ | 3457.44 |
| | Fronius IG Plus 6.0 | 6000 | No | Yes | No | ~~5560~~ | 3576.44 |
| | Fronius IG Plus 7.5 | 7500 | No | Yes | No | ~~6430~~ | 4356.00 |
| Outback | FX2012MT | 2000 | Yes | No | Yes | ~~2369~~ | 1809.54 |
| | FX2012T | 2000 | Yes | No | Yes | ~~2369~~ | 1809.54 |
| | FX2524T | 2500 | Yes | No | Yes | ~~2369~~ | 1809.54 |
| | FX3048T | 3000 | Yes | No | Yes | ~~2369~~ | 1809.54 |
| | GTFX2524 | 2500 | Yes | Yes | Yes | ~~2369~~ | 1809.54 |
| | GTFX3048 | 3000 | Yes | Yes | Yes | ~~2369~~ | 1809.54 |
| | GVFX3648 | 3600 | Yes | Yes | Yes | ~~2569~~ | 1962.31 |
| | GVFX3524 | 3500 | Yes | Yes | Yes | ~~2569~~ | 1962.31 |
| | VFX2812 | 2800 | Yes | No | Yes | ~~2569~~ | 1962.31 |
| | VFX3524 | 3500 | Yes | No | Yes | ~~2569~~ | 1962.31 |
| | VFX3648 | 3600 | Yes | No | Yes | ~~2569~~ | 1962.31 |
| PV Powered | PVP 1100 | 1100 | No | Yes | No | | 1592.00 |
| New inverters now include system disconnect | PVP 2000 | 2000 | No | Yes | No | | 1663.00 |
| | PVP 2500 | 2500 | No | Yes | No | | 1851.00 |
| | PVP 2800 | 2800 | No | Yes | No | | 2011.00 |
| | PVP 3000 | 3000 | No | Yes | No | | 2011.00 |
| | PVP 3500 | 3500 | No | Yes | No | | 2189.00 |
| | PVP 4600 | 4600 | No | Yes | No | | 2670.00 |
| | PVP 4800 | 4800 | No | Yes | No | | 2693.00 |

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| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | PVP 5200 | 5200 | No | Yes | No | | 2852.00 |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| **Inverter Manuf.** | **Model** | **Wattage** | **Charger?** | **Grid Intertie?** | **Battery Backup?** | **List** | **Our Price (US $)** |
| **SMA America** | | | | | | | |
| | SB3000US | 3000 | No | Yes | No | ~~3431.97~~ | 1835.00 |
| | SB4000US | 4000 | No | Yes | No | ~~3749.38~~ | 2325.00 |
| | SB5000US | 5000 | No | Yes | No | ~~5138.04~~ | 3040.00 |
| | SB6000US | 6000 | No | Yes | No | ~~5276.91~~ | 3261.00 |
| | SB7000US | 7000 | No | Yes | No | ~~5733.18~~ | 3522.00 |
| **Xantrex** | | | | | | | |
| | GT 3.3 | 3300 | No | Yes | No | ~~2875~~ | 2125.00 |
| | GT 3.8 | 3800 | No | Yes | No | | 2138.00 |
| | GT 4.0 | 4000 | No | Yes | No | ~~3130~~ | 2313.70 |
| | GT 5.0 | 5000 | No | Yes | No | ~~3950~~ | 2698.00 |
| | XW4024-120/240-60 | 4000 | Yes | Yes | Yes | ~~3250~~ | 2919.84 |
| | XW4548-120/240-60 | 4500 | Yes | Yes | Yes | ~~3600~~ | 2919.84 |
| | XW6048-120/240-60 | 6000 | Yes | Yes | Yes | ~~4500~~ | 3326.40 |

*Note: Prices subject to change. Verify prices before placing order.*
*Contact us for pricing on inverters not listed.*

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## Solar Panel Pricing

We have special pricing on BP, REC, Sharp, Evergreen solar panels for a limited time only.

Email us at info@beyondoilsolar.com for updates and to discuss your needs.

| Module Manuf. | Model | Watts | Nominal Voltage | Module Quantity | Price per Watt (US $) | Price (US $) | |
|---|---|---|---|---|---|---|---|
| BP | BP175B | 175 | 24V | 2 + | $2.63 | 461.00 | BP175B pdf |
| BP | SX3190B | 190 | 16V | 2 + | | Call | SX3190B pdf |
| BP | SX3200B | 200 | 16V | 2 + | | Call | SX3200B pdf |

| Limited time specials | Model | Watts | Nominal Voltage | Price per Watt (US$) | Price 2+ Modules (US$) | Call for pricing on larger orders | |
|---|---|---|---|---|---|---|---|
| Sharp | NE-170UC1 | 170 | 24V | $2.96 | 503.20 | | NE-170U1.pdf |
| Sharp | NT-175UC1 | 175 | 24V | $2.80 | 490.00 | | NT-175U1. pdf |
| Sharp | ND-216UC1 | 216 | 18V | $2.96 | 639.36 | | ND-216U1F.pdf |
| Sharp | ND-224UC1 | 224 | 18V | $2.96 | 663.04 | | ND-224U1F.pdf |
| Sharp | ND-U230C1 (polycryst.) | 230 | 18V | $2.70 | 621.00 | | ND-230C1.pdf |
| Sharp | NU-U230F3 (monocryst.) | 230 | 18V | $2.80 | 644.00 | | NU-U230F3.pdf |
| Sharp | NU-U235F1 (monocryst.) | 235 | 18V | $2.70 | 634.50 | | NU-U235F1.pdf |
| Sharp | ND-N2ECUF | 142 | 14V | Call | Call | | ND-N2ECUF.pdf |
| (Triangular) Use with ND-N2ECUF | ND-72ERUF/ ND-72ELUF | 72 | 7V | Call | Call | | ND-72ERUF.pdf |

| Limited time specials | Model | Watts | Nominal Voltage | Price per Watt (US$) | Module Quantity | Price (US$) | |
|---|---|---|---|---|---|---|---|
| Evergreen | ES-A-195 | 195 | 12V | $2.97 | 1-5 | 579.15 | |
| | | | | $2.76 | 6-29 | 538.20 | |
| | | | | $2.65 | 30+ | 516.75 | |
| Evergreen | ES-A-200 | 200 | 12V | $3.16 | 1-5 | 632.00 | ES-A-200.pdf |
| | | | | $2.93 | 6-29 | 586.00 | |
| | | | | $2.82 | 30+ | 564.00 | |
| Evergreen | ES-A-205 | 205 | 12V | $2.97 | 1-5 | 608.85 | ES-A-205.pdf |
| | | | | $2.76 | 6-29 | 565.80 | |
| | | | | $2.65 | 30+ | 543.25 | |

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|---|---|---|---|---|---|---|---|
| **Evergreen** | ES-A-210 | 210 | 12V | $2.97 | 1-5 | 623.70 | ES-A-210.pdf |
| | | | | $2.76 | 6-29 | 579.60 | |
| | | | | $2.65 | 30+ | 556.50 | |
| | | | | | | | |
| Limited time specials | **Model** | **Watts** | **Nominal Voltage** | **Module Quantity** | **Price per Watt (US$)** | **Price (US$)** | |
| **REC** | **REC210AE-US** | 210 | 18V | 2 to 29 | $2.63 | 551.84 | REC-AE-Series.pdf |
| | REC210AE-US | 210 | 18V | 30 + | $2.44 | 512.48 | REC-AE-Series.pdf |
| **REC** | **REC215AE-US** | 215 | 18V | 2 to 29 | $2.64 | 568.67 | REC-AE-Series.pdf |
| | REC215AE-US | 215 | 18V | 30 + | $2.45 | 527.99 | REC-AE-Series.pdf |
| **REC** | **REC220AE-US** | 220 | 18V | 2 to 29 | $2.67 | 588.05 | REC-AE-Series.pdf |
| | REC220AE-US | 220 | 18V | 30 + | $2.48 | 545.85 | REC-AE-Series.pdf |
| **REC** | **REC225AE-US** | 225 | 18V | 2 to 29 | $2.70 | 608.45 | REC-AE-Series.pdf |
| | REC225AE-US | 225 | 18V | 30 + | $2.51 | 564.65 | REC-AE-Series.pdf |
| **REC** | **REC230AE-US** | 230 | 18V | 2 to 29 | $2.70 | 620.69 | REC-AE-Series.pdf |
| | REC230AE-US | 230 | 18V | 30 + | $2.50 | 575.93 | REC-AE-Series.pdf |
| | | | | | | | |
| Limited time specials | **Model** | **Watts** | **Nominal Voltage** | **Module Quantity** | **Price per Watt (US$)** | **Price (US$)** | |
| **SUNTECH** | **STP170S-24/Ab-1** | 170 | 24V | 26+ | $2.60 | 442.00 | STP175S-24.pdf |
| **Also available with black frame** | **STP175S-24/Ab-1** | 175 | 24V | 26+ | $2.60 | 455.00 | STP175S-24.pdf |
| | **STP180S-24/Ab-1** | 180 | 24V | 26+ | $2.60 | 468.00 | STP175S-24.pdf |
| | | | | | | | |
| | Ask for quotes on larger quantities of pv panels. | | | | | | |

Call for pricing on UniSolar, SolarWorld, Yingli Solar and Kaneka photovoltaic panels.

*Note: Prices subject to change. Please verify prices before placing order.*

# CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **Opening Comments of Portland General Electric Company** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service from OPUC Docket Nos. AR 538 and UM 1452.

Dated in Portland, Oregon, this 14th day of January, 2010.

J. Richard George

J. RICHARD GEORGE

* Waived Paper Service

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| TEDDY KEIZER<br>1615 SE 30TH AVE<br>PORTLAND OR 97214<br>teddy@goteddygo.com; teddy1a@aol.com * | RAYMOND P NEFF<br>465-1/2 RIVER RD<br>EUGENE OR 97404<br>rpneff@efn.org * |
| DANIEL WELDON<br>19790 SOUTH FERGUSON TERRACE<br>OREGON CITY OR 97045<br>danweldon@bctonline.com * | **CABLE HUSTON BENEDICT HAAGENSEN & LLOYD, LLP**<br>RAYMOND S KINDLEY<br>1001 SW FIFTH AVENUE, SUITE 2000<br>PORTLAND OR 97204-1136<br>rkindley@cablehuston.com * |
| **CITIZENS' UTILITY BOARD OF OREGON**<br>GORDON FEIGHNER<br>ENERGY ANALYST<br>610 SW BROADWAY, SUITE 308<br>PORTLAND OR 97205<br>gordon@oregoncub.org * | **CITIZENS' UTILITY BOARD OF OREGON**<br>ROBERT JENKS<br>610 SW BROADWAY STE 308<br>PORTLAND OR 97205<br>bob@oregoncub.org * |
| **CITIZENS' UTILITY BOARD OF OREGON**<br>G. CATRIONA MCCRACKEN<br>LEGAL COUNSEL/STAFF ATTY<br>610 SW BROADWAY - STE 308<br>PORTLAND OR 97205<br>catriona@oregoncub.org * | **DAVISON VAN CLEVE**<br>IRION A SANGER<br>ASSOCIATE ATTORNEY<br>333 SW TAYLOR - STE 400<br>PORTLAND OR 97204<br>ias@dvclaw.com |
| **DAVISON VAN CLEVE PC**<br>MELINDA J DAVISON<br>333 SW TAYLOR - STE 400<br>PORTLAND OR 97204<br>mail@dvclaw.com | **DEPARTMENT OF JUSTICE**<br>STEPHANIE S ANDRUS<br>ASSISTANT ATTORNEY GENERAL<br>REGULATED UTILITY & BUSINESS SECTION<br>1162 COURT ST NE<br>SALEM OR 97301-4096<br>stephanie.andrus@state.or.us |
| **ECUMENICAL MINISTRIES OF OREGON**<br>JENNY HOLMES<br>ENVIRONMENTAL MINISTRIES DIRECTOR<br>0245 SW BANCROFT, SUITE B<br>PORTLAND OR 97239<br>jholmes@emoregon.org * | **ECUMENICAL MINISTRIES OF OREGON**<br>KATHLEEN NEWMAN<br>OREGON INTERFAITH POWER & LIGHT<br>1553 NE GREENSWORD DR<br>HILLSBORO OR 97214<br>knewman@emoregon.org;<br>k.a.newman@verizon.net * |
| **ENERGY TRUST OF OREGON**<br>KACIA BROCKMAN<br>851 SW SIXTH AVE - STE 1200<br>PORTLAND OR 97204<br>kacia@energytrust.org * | **ENERGY TRUST OF OREGON**<br>JOHN M VOLKMAN<br>GENERAL COUNSEL<br>851 SW 6TH AVE SUITE 1200<br>PORTLAND OR 97204 *<br>john.volkman@energytrust.org |

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| **ENVIRONMENTAL LAW ALLIANCE WORLDWIDE**<br>JENNIFER GLEASON<br>1877 GARDEN AVE<br>EUGENE OR 97403<br>jen@elaw.org * | **ESLER STEPHENS & BUCKLEY**<br>JOHN W STEPHENS<br>888 SW FIFTH AVE STE 700<br>PORTLAND OR 97204-2021<br>stephens@eslerstephens.com * |
| **IDAHO POWER COMPANY**<br>RANDY ALLPHIN<br>rallphin@idahopower.com * | **IDAHO POWER COMPANY**<br>CHRISTA BEARRY<br>PO BOX 70<br>BOISE ID 83707-0070<br>cbearry@idahopower.com * |
| **IDAHO POWER COMPANY**<br>KARL BOKENKAMP<br>GENERAL MANAGER-POWER SUPPLY PLANNING<br>PO BOX 70<br>BOISE ID 83707-0070<br>kbokenkamp@idahopower.com * | **IDAHO POWER COMPANY**<br>RICK GALE<br>rgale@idahopower.com * |
| **IDAHO POWER COMPANY**<br>BARTON L KLINE<br>SENIOR ATTORNEY<br>PO BOX 70<br>BOISE ID 83707-0070<br>bkline@idahopower.com * | **IDAHO POWER COMPANY**<br>JEFF MALMEN<br>PO BOX 70<br>BOISE ID 83707-0070<br>jmalmen@idahopower.com * |
| **IDAHO POWER COMPANY**<br>LISA D NORDSTROM<br>ATTORNEY<br>PO BOX 70<br>BOISE ID 83707-0070<br>lnordstrom@idahopower.com * | **IDAHO POWER COMPANY**<br>GREGORY W SAID<br>DIRECTOR - REVENUE REQUIREMENT<br>PO BOX 70<br>BOISE ID 83707<br>gsaid@idahopower.com * |
| **IDAHO POWER COMPANY**<br>MARK STOKES<br>MANAGER, POWER SUPPLY & PLANNING<br>PO BOX 70<br>BOISE ID 83707<br>mstokes@idahopower.com * | **IDAHO POWER COMPANY**<br>MICHAEL YOUNGBLOOD<br>SENIOR PRICING ANALYST<br>PO BOX 70<br>BOISE ID 83707<br>myoungblood@idahopower.com * |
| **MCDOWELL & RACKNER PC**<br>WENDY MCINDOO<br>OFFICE MANAGER<br>520 SW 6TH AVE STE 830<br>PORTLAND OR 97204<br>wendy@mcd-law.com * | **MCDOWELL & RACKNER PC**<br>LISA F RACKNER<br>ATTORNEY<br>520 SW SIXTH AVENUE STE 830<br>PORTLAND OR 97204<br>lisa@mcd-law.com * |
| **MULTNOMAH COUNTY**<br>WARREN FISH<br>501 SE HAWTHORNE, STE 600<br>PORTLAND OR 97214<br>warren.fish@co.multnomah.or.us * | **MULTNOMAH COUNTY COMMISSIONER**<br>COMMISSIONER JEFF COGEN<br>501 SE HAWTHORNE, STE 600<br>PORTLAND OR 97214<br>district2@co.multnomah.or.us * |

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|---|---|
| **OREGON AFL-CIO**<br>2110 STATE ST<br>SALEM OR 97301<br>afl-cio@oraflcio.org; duke@oraflcio.org | **OREGON AFL-CIO**<br>JOHN BISHOP<br>1635 NW JOHNSON ST<br>PORTLAND OR 97209<br>jbishop@mbjlaw.com |
| **OREGON DISTRICT COUNCIL OF LABOERS**<br>BEN NELSON<br>10245 SE HOLGATE BLVD<br>PORTLAND OR 97266<br>nrocnelson@qwest.net * | **OREGON DISTRICT COUNCIL OF LABORERS'**<br>MELODY GUY<br>melodyg@qwestoffice.net * |
| **OREGONIANS FOR RENEWABLE ENERGY PAYMENTS**<br>JUDY BARNES<br>1425 SE 37TH<br>PORTLAND OR 97214<br>jbarnes@hevanet.com * | **OREGONIANS FOR RENEWABLE ENERGY PAYMENTS**<br>MARK PETE PENGILLY<br>PO BOX 10221<br>PORTLAND OR 97296<br>mpengilly@gmail.com * |
| **PACIFICORP**<br>RYAN FLYNN<br>825 NE MULTNOMAH, SUITE 1800<br>PORTLAND OR 97232<br>ryan.flynn@pacificorp.com * | **PACIFICORP, DBA PACIFIC POWER**<br>PACIFIC POWER OREGON DOCKETS<br>825 NE MULTNOMAH STREET, STE 2000<br>PORTLAND OR 97232<br>oregondockets@pacificorp.com * |
| **PGE RATES & REGULATORY AFFAIRS**<br>DOUG KUNS<br>PORTLAND GENERAL ELECTRIC COMPANY<br>121 SW SALMON STREET, 1WTC0702<br>PORTLAND OR 97204<br>pge.opuc.filings@pgn.com | **PORTLAND GENERAL ELECTRIC COMPANY**<br>J RICHARD GEORGE<br>121 SW SALMON ST 1WTC1301<br>PORTLAND OR 97204<br>richard.george@pgn.com |
| **PUBLIC UTILITY COMMISSION OF OREGON**<br>THERESA GIBNEY<br>PO BOX 2148<br>SALEM OR 97308<br>theresa.gibney@state.or.us | **RENEWABLE NORTHWEST PROJECT**<br>ANN ENGLISH GRAVATT<br>917 SW OAK - STE 303<br>PORTLAND OR 97205<br>ann@rnp.org * |
| **RENEWABLE NORTHWEST PROJECT**<br>SUZANNE LETA LIOU<br>917 SW OAK STE 303<br>PORTLAND OR 97205<br>suzanne@rnp.org * | **SOLAR ENERGY SOLUTIONS, INC.**<br>ANDREW KOYAANISQATSI<br>3730 SE LAFAYETTE CT<br>PORTLAND OR 97202<br>andrew@solarenergyoregon.com * |
| **SOUTHEAST UPLIFT NEIGHBOORHOOD COALITION**<br>TIM O'NEIL<br>3534 SE MAIN ST<br>PORTLAND OR 97212<br>tim@southeastuplift.org * | **SUNEDISON**<br>JOE HENRI<br>12500 BALTIMORE AVE<br>BELTSVILLE MD 20705<br>jhenri@sunedison.com * |
| **SUSTAINABLE SOLUTIONS UNLIMITED LLC**<br>STEVEN MCGRATH | |

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|---|---|
| 1339 SE 8TH AVE # B<br>PORTLAND OR 97214<br>steve@solutions21st.com * | |