Davison Van Cleve PC

TEL (503) 241-7242 • FAX (503) 241-8160 • mail@dvclaw.com

Suite 2460
1000 SW Broadway
Portland, OR 97205

August 3, 2004

Via Facsimile and U.S. Mail
Carol Hulse
Oregon Public Utility Commission
550 Capitol Street, N.E., Suite 215
Salem OR 97308-2148

Re: In the Matter of an Investigation Relating to Electric Utility Purchases From Qualifying Facilities
Docket No. UM 1129

Dear Ms. Hulse:

Enclosed please find the original and six (6) copies of the Direct Testimony of Donald W. Schoenbeck on behalf of the Industrial Customers of Northwest Utilities in the above-captioned Docket.

Please return one file-stamped copy of the document in the self-addressed, stamped envelope provided.

Thank you for your assistance.

Sincerely yours,

Ruth A. Miller

Enclosures
cc: Service List

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1129

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON STAFF's	)
	)
	)
Investigation Relating to Electric Utility Purchases From Qualifying Facilities.	)
	)
	)

DIRECT TESTIMONY OF

DONALD W. SCHOENBECK

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

August 3, 2004

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald W. Schoenbeck. I am a member of Regulatory & Cogeneration Services, Inc. ("RCS"), a utility rate and economic consulting firm. My business address is 900 Washington Street, Suite 780, Vancouver, WA 98660.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I've been involved in the electric and gas utility industries for over 30 years. For the majority of this time, I have provided consulting services for large industrial customers addressing regulatory and contractual matters before numerous state commissions, public utility governing boards, governmental agencies, state and federal courts, the National Energy Board of Canada and the Federal Energy Regulatory Commission ("FERC"). A further description of my educational background and work experience is summarized in Exhibit ICNU/101.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association, whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including Portland General Electric ("PGE") and PacifiCorp.

Introduction: Why Oregon Lags in the Development of Qualifying Facilities ("QF")

Q. THE COMMISSION HAS OPENED THIS INVESTIGATION TO EXAMINE THE IMPLEMENTATION OF THE PUBLIC UTILITY REGULATORY POLICY ACT ("PURPA") IN OREGON. WHAT DO YOU SEE AS THE PROBLEM THAT NEEDS TO BE ADDRESSED?

A. Past implementation of PURPA in Oregon has severely restricted QF development due to three fundamental hurdles. First, the one megawatt ("MW") limit on standard offer contracts is woefully inadequate. PURPA is intended to encourage the development of cost-effective, non-utility and environmentally beneficial generation resources, including cogeneration. PURPA, 16 U.S.C. § 2611; Re Requirements of Section 111 of the Energy Policy Act, OPUC Docket No. UM 712, Order No. 95-627 (June 23, 1995); Re Gaylord Container Corp., 107 F.E.R.C. ¶ 61,203 at 61, 903 (2004). Consigning all projects in excess of one MW to bilateral negotiations with the utility appears to have severely limited the number of QFs in Oregon.

Second, standard offer contracts are limited to a maximum of five years. Potential QF developers need some ability to assess the probability of recovering the investment in their project. Five years is an insufficient time period to provide any prospect of recovery. For the developer to gain a longer term, they must resort to bilateral contract negotiations with the utility. This gives a tremendous advantage to the utility to stifle projects for any reason.

Third, the exclusion of capital costs from utility avoided costs during "surplus" periods makes it extremely difficult for projects to gain economic viability. This also gives a tremendous advantage to the utility in bilateral negotiations by placing an implicit price cap on any contract. Even if the utility desired to add the project to their portfolio, the utility would face a large amount of work to justify payments in excess of their avoided costs.

As a result of the problems with implementing PURPA, Oregon has missed a number of opportunities to add beneficial resources to the state's resource portfolio. Combined, all of these hurdles have restricted development of QFs in Oregon to about 0.7% of nameplate capacity[1/] in the state. Exhibit ICNU/102. While this places

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1/ The statistics presented here are based on EIA-860 data for 2002, the most recent year available.

Oregon 34th out of the 50 states, it is substantially below the 5.1% average of the entire United States. Id.

Oregon ranks better in the development of combined heat and power generation, placing 18th with 5.9% of nameplate capacity. Id. However, the new Klamath Falls generating project accounts for 70% of the installed cogeneration in the state. Without that one plant, which was developed by a power marketer more as a merchant power plant with its steam production being an ancillary product, Oregon would fall to 33rd in the country with 1.8% of its installed capacity being cogeneration.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF OREGON'S RESTRICTED QF DEVELOPMENT.

A. In order to stimulate certain types of renewable resources, Oregon has now included a public purposes charge on each end-user of electricity, which in part funds new renewable resources. The need for this charge would have been diminished had PURPA implementation been more successful. Better PURPA implementation could have either lowered the level of the charge or allowed for its use for other purposes.

Q. WHAT ARE SOME OF THE BENEFITS OF HAVING MORE QFs IN THE STATE?

A. There are a number of benefits from increasing the amount of QF generation in Oregon. I will discuss the benefits of cogeneration.

The first benefit is efficiency. Because they produce both heat and electricity, cogeneration facilities on average are more than 40% more efficient than separate natural gas-fueled electric generating plants and gas-fueled steam plants. When factoring in both electrical generation and useful thermal production, cogeneration is 33% more efficient than the most modern power production facilities and twice as efficient as most other energy producers.

The second benefit is reliability. A system of 50 smaller generators of 200 MW each is significantly more reliable than a similar size system of 20 larger generators of 500 MW each. The smaller unit system is 100 times less likely to lose 1,000 MW of capacity simultaneously.

The third benefit is increased utilization. Cogeneration plants produce electricity an average of 90% of the time, compared to stand-alone electric generating plants that operate an average of just 60% of the time.

The fourth benefit is system diversity. Because they distribute electrical generation among smaller, more efficient generating facilities, policies that promote cogeneration increase the reliability of an energy portfolio in the same way a diversified investment strategy protects investors.

The fifth benefit is transmission reliability. Cogeneration provides a major source of distributed generation for the electric grid which is a significant operating benefit. By providing multiple power sources throughout the state, the demand on the state's electrical grid and the risks of losing power when centralized generating facilities fail is reduced.

The sixth benefit is business development. Small cogeneration facilities can provide a source of reliable energy to hospitals, schools, churches, municipal buildings and businesses. Larger industries can turn to cogeneration as a reliable source of power for their own operations.

The seventh benefit is environmental. Because it uses one source of natural gas to produce both electricity and heat, cogeneration saves natural gas. The natural gas saved by cogeneration also translates to significant reductions in emissions.

In California, cogeneration reduces greenhouse gas emissions (CO_2) by more than 18 million tons per year and cuts smog emissions (NO_x) by 5,400 tons per year. These CO_2 emissions reductions are the equivalent of removing almost 4 million cars (3,988,006) from the highways. The NO_x emissions reductions are the equivalent of removing 459,000 cars from the highway.

The eighth benefit is reduced transmission losses. Cogeneration conserves electricity by producing power near the places it is consumed. This reduces transmission losses and saves an additional amount of fuel from being burned.

The ninth benefit is customer choice. Cogeneration enables large industrial and other customers to manage and stabilize energy costs. Customer generation serves as an important check on market prices.

The tenth benefit is the contribution to the state economy. By supplying an alternative source of power, cogenerators help moderate market price volatility for business and industrial consumers. This helps keep businesses profitable and employing workers. It introduces new investment into the state, providing jobs, not just during construction, but during the operational life of both the generating facility and the thermal host.

The eleventh benefit is ratepayer savings. By diversifying the sources of electricity used to meet the state's total energy needs, cogeneration helps make the electric system more affordable by increasing electricity dedicated to serve Oregon. By producing more electricity for the state using private investment dollars, cogeneration lowers the price of energy. Further, should plant upgrades be required, either for energy production or for environmental mitigation, the QF owner pays rather than the ratepayer.

Finally, should the plant fail prematurely for some reason, the ratepayer is not responsible for any stranded costs associated with the plant; the QF owner bears the full cost of the failure.

Q. CAN'T QF DEVELOPERS SIMPLY RELY ON NEGOTIATED CONTRACTS SINCE THE RESTRICTIONS APPLY ONLY TO STANDARD OFFER CONTRACTS?

A. No. Forcing almost all prospective QF developers into bilateral negotiations gives a tremendous negotiating advantage to the utility. First, the utility has a more complete view of the resource development landscape than an individual developer. Second, the utility has a natural tendency to favor its own resource plans. The utility disfavors QF development and can hold a hard line with competing resources that are forced to negotiate with the utility. Third, delaying or prolonging the negotiating process by the utility works in favor of the utility. As a result, QF negotiations usually end in frustration.

Q. WHAT ARE THE PROBLEMS YOU SEE WITH THE AVOIDED COST DEVELOPMENT?

A. The fundamental problem in developing the utility's avoided cost is that capital costs are excluded until the utility is resource deficit. In PacifiCorp's recent Integrated Resource Plan ("IRP"), a resource deficit is not projected to occur until 2007. Prudent utility planning will result in the procurement of additional resources in advance of their need, meaning that when 2007 arrives, PacifiCorp will not be resource deficit. Prior to 2007, PacifiCorp will conduct another IRP that will show that the year they are resource deficit has been extended into the future. This will lead to another avoided cost filing that will again postpone the period in which capital costs could be included in the avoided cost calculation.

What this means is that capital costs would most likely never be included in any current calculation of avoided costs. As I stated above, the exclusion of capital costs from the avoided cost calculation makes it very difficult for a QF developer to show a return of their investment, not to mention a return on their investment. In contrast, utilities recover a return of, and return on, their investments in self-built plants.

The lower avoided cost also gives a tremendous negotiating advantage to the utility in bilateral negotiations. It puts a virtual price cap on a negotiated contract that is below the cost of construction, restricting the ability of a developer to recover the costs of a project, no matter how desirable the project might be.

Q. WHAT ARE YOUR RECOMMENDATIONS FOR CHANGES TO STANDARD OFFER CONTRACTS?

A. First, the one MW limit should be removed. I favor no size cap, but should a cap be found necessary, I would be willing to support a reasonable size. I would suggest that a 40 MW (capacity) cap would encompass most potential non-wind resources. I do not believe that a cap is necessary for wind resources due to the developing technologies of wind generators, the economies of scale, and its low energy output relative to capacity. Removal or increasing the size limitation will be critical for the successful development of QFs in Oregon, thereby enhancing the diversity of resources, both in type and in ownership. A more diverse resource pool allows for a more competitive supply of energy within the state, which ultimately benefits ratepayers.

Second, I would allow longer terms for standard offer contracts. The term should be extended to a standard time period depending on the investment life of each type of resource. The term of the contract should be tied to the investment life of the facility in order to provide QF developers with the ability to earn a return on their investment.

Third, I would reformulate the avoided cost calculations to include capital costs so that developers have a fair chance of recovering their investment. Reformulating the avoided cost calculations is essential to giving QF developers a more equal footing to compete with the utility regarding future resource development.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATIONS ON RATEPAYERS? WON'T RATEPAYERS BE HARMED BY OVER-DEVELOPMENT OF COSTLY QF RESOURCES?

A. The federal PURPA was implemented to encourage QF development in balance with ratepayer interests. Payments to QF developers are limited to the utility's avoided costs; that is, the cost the utility would have to pay for incremental resources.

There are two potential ways that ratepayers might be harmed with a less restrictive implementation of the federal PURPA. First, the utility might pay more for resources through the avoided cost calculation than through a competitive bid. Second, the utility might be forced to purchase more resources than it needs if there is a huge influx of QF resources seeking standard offer contracts.

Each of these circumstances can be addressed with sensible safeguards in the implementation rules. First, a more realistic and accurate calculation of the avoided cost will eliminate the possibility that the utility pays more than necessary for a QF resource. This puts a burden on the utility to correctly present their avoided cost, and it puts a burden on the Commission to ensure that the avoided cost is fair to both the QF developer and the ratepayers. Second, a safety valve should allow the utility to lower its avoided cost or seek the suspension of standard offer contracts when the utility's or the region's load/resource thresholds are reached. This will minimize the potential for the utility buying too many resources or purchasing from QFs when the region is facing a surplus that causes power prices that are lower than the utility's filed avoided costs. This safety valve should be set high enough above the load resource balance to encompass planning margins, and to balance the interests of the QF developer and the ratepayer, but not low enough to give a competitive advantage to the utility to develop its own resources. It should be remembered that the federal PURPA was established to encourage QF development and remove barriers to the development of non-utility generation resources. *See* Swecker v. Midland Power Coop., 105 F.E.R.C. ¶ 61,238 (2003).

Under the current Oregon implementation, the utility is benefited because they have an implicit veto on almost all QF development, while the QF developers are shut out from a fair chance for consideration for their projects. The current implementation favors utility development over a more competitively diverse, efficient, and environmentally cleaner power supply. Customers may be paying more in their rates for power supply because a potential, highly-efficient supply is being systematically excluded from practical consideration.

Issue 1: Contract Length and Price Structure:

Q. WHAT IS THE APPROPRIATE CONTRACT LENGTH THAT IS CONSISTENT WITH THE FEDERAL PURPA STANDARDS AND WILL BALANCE THE INTERESTS OF THE QF DEVELOPERS AND THE UTILITY'S CUSTOMERS?

A. The current practice of a five-year term for standard offer contracts is insufficient and limits the development of many cost-effective QFs, thereby thwarting the federal PURPA standards and goals.[2/] The contract term should be sufficient to recover investment in the

[2/] In their January 16, 2004 preliminary written comments, PacifiCorp has characterized PURPA's goals as "twin aims of encouraging efficient development of distributed resources and ratepayer neutrality."

facility, that is, the investment life of the facility. The maximum term should be allowed to vary based upon the technology of the QF resource. For example, this could allow up to 30 years for a gas-fired cogeneration project, up to 50 years for a hydro facility, 20 years for a wind facility, and 10-15 years for a biomass facility.

By restricting the term to less than the investment life of the facility, the developer would need a higher price to compensate for the shorter term to recover the investment. This means either that cost-effective projects will not be built, or they will be priced higher than they need to be. The term should be selected by the QF developer, as long as it is within the maximum parameters set by the Commission. This gives better incentives to developers to invest in generating facilities with some certainty of recovery of investment. This also provides for a more diversified power supply, ultimately benefiting the ratepayers by matching the pricing of the project with the investment life of the project.

Q. WHAT IS THE APPROPRIATE PRICING STRUCTURE (e.g., PRICES THAT VARY BY YEAR, OR PRICES THAT ARE LEVELIZED OVER THE CONTRACT TERM), AND SHOULD THE COMMISSION SPECIFY THAT STRUCTURE?

A. The pricing structure for standard offer contracts should be more predictable, allowing an investor to determine if the potential facility is economically feasible. Whether the prices vary by year or are levelized is of less concern than assuring that they are predictable. However, to say that prices are predictable does not necessarily mean that they are known. For example, the prices may be tied to some gas or electricity price index. But they should not be dependent upon specific conditions relating to the utility, such as whether the utility is resource surplus.

The Commission should set parameters for standard offer contracts and allow flexibility in negotiated contracts. The specific prices or pricing formula should be fixed for the duration of the agreement. Once again, this gives the QF developer more certainty that its investment will be recovered, thereby encouraging further development of QF resources.

Also, standardized pricing structures should be offered for the various types of resources—just as is essentially done for utility-owned resources. This allows cost recovery to be tied to the costs as they are incurred; there should be no difference between QFs and utility-owned resources. In other words, a capital intensive resource (such as wind, solar, and hydro) should be given the option to elect a fixed price series that is not tied to a gas—or other variable—index. Similarly, a gas or coal fired resource should be allowed to elect to have *a portion* of its payment indexed to an appropriate benchmark. Under this latter approach, the fixed capital related costs should be recoverable through a fixed payment and the variable (fuel-related) costs recovered through an index. Under an index election, there should be no floors or ceilings imposed.

Issue 2: Size Threshold for Standard Rates:

Q. WHAT SIZE FACILITIES SHOULD BE ELIGIBLE FOR STANDARD PURCHASE RATES AND A STANDARD POWER PURCHASE AGREEMENT?

A. There should be no size limitation. If and when more QFs are developed than necessary to meet the utility's load, the utility may file to suspend the standard offers and/or the avoided cost price. There have been no size limitations in states where QF development has been very successful. However, in recognition of the smaller size of Oregon's investor-owned utilities, ICNU is willing to support a size cap of 40 MW for non-wind resources. This capacity cap would also correct a current regulatory gap between the existing size limitation allowed under the Oregon standard offers and the utility Requests for Proposals ("RFPs"). The RFPs do not even allow for resource bids below 25 MW for certain facilities.

Issue 3. Utility Tariff Content:

Q. WHAT PRICES, TERMS, AND CONDITIONS SHOULD BE INCLUDED IN UTILITY TARIFFS?

A. The utilities should be required to depend more upon standard offers than negotiated contracts. This would lead to prices, terms, and conditions that are structured to maximize the cost-effective development of QFs. The current tariffs are tailored for small projects that are less than one MW in size. Care needs to be taken in this process to make sure that the provisions do not discriminate against larger QFs. Upon conclusion of this investigation, the utilities should be required to file conforming tariffs that comply with the Commission's decisions. At that time, parties should be allowed to review the tariffs and present necessary changes.

Q. HOW SHOULD THE COMMISSION ENSURE THAT ALL TERMS AND CONDITIONS IT APPROVES IN THE AVOIDED COST FILINGS ARE PUBLICLY AVAILABLE?

A. A greater reliance on standard offers would help ensure than all terms and conditions are publicly available. This has the added benefit of minimizing the opportunities for utility discretion that might lead to discrimination or preference for utility-developed resources. A follow-on process to review compliance filings would assist the Commission in making these necessary assurances.

Issue 4. Avoided Cost Calculation Methods:

Q. WHAT IS THE APPROPRIATE METHOD FOR CALCULATING AVOIDED COSTS?

A. The avoided cost calculation should assume that the utility is in load/resource balance. Full capacity and energy prices should be included, even in advance of supply deficits. Current practice limits the opportunities for new development because the utility will always have resources in excess of expected loads due to planning and margin requirements. For example, PacifiCorp is currently not expecting any deficits until 2007 and yet PacifiCorp has added utility owned or contracted for resources in recent years and is continuing to seek RFPs for additional resources. *See, e.g.* Re PacifiCorp, OPUC Docket No. UI 196 (West Valley lease). (By the time 2007 approaches, they will have added resources, resulting in extending the date at which supply deficits would occur.) This results in situations where capacity costs are never included in avoided cost calculations. It further mandates that the potential QF wait for the utility to issue an RFP and hope that it gets selected.

The appropriate method for determining the price is to calculate the avoided costs from utility specific resource plans or simply use a surrogate resource such as a Combined Cycle Combustion Turbine ("CCCT"). This latter approach is more practical in this instant proceeding under which standard pricing options are being developed. The Idaho Commission has used the cost of a CCCT as the resource for determining resource acquisition costs from QFs. Re Revision of and Updated Calculation of Avoided Costs Rates, Idaho PUC Order No. 29391 (Dec. 5, 2003). The California Commission has established the cost of a CCCT as the proxy market price referent for baseload plants, where any plant priced less than that level would be considered *per se* reasonable. Re Opinion Adopting Market Price Referent Methodology, CPUC Decision 04-06-015 (June 9, 2004). ICNU recommends the Oregon Commission adopt the CCCT approach as well.

Issue 5. Applicability of Oregon PURPA Administrative Rules:

Q. SINCE FEDERAL PURPA STILL APPLIES TO ALL ELECTRIC COMPANIES AND THE COMMISSION IS RESPONSIBLE FOR ITS IMPLEMENTATION, WHAT IS THE PRACTICAL EFFECT OF THE ORS § 757.612 EXEMPTION FOR PGE AND PACIFICORP?

A. The administrative rules need further review to differentiate the rules that implement federal PURPA from the rules that were specific to Oregon PURPA law. Conforming the Oregon administrative rules to better implement the purposes of the federal PURPA will greatly enhance the opportunities for cost-effective QF development. The federal PURPA was designed to encourage the development of CHP and renewable energy sources because of their desirable environmental impacts. Current Oregon rules restrict QF development and leave the environmental beneficial development of CHP under-developed in the state. Compared to other states, Oregon lags in the development of cogeneration.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

UM 1129

EXHIBIT ICNU/101

QUALIFICATIONS

DONALD W. SCHOENBECK

QUALIFICATIONS AND BACKGROUND
OF
DONALD W. SCHOENBECK

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Donald W. Schoenbeck, 900 Washington Street, Suite 780, Vancouver, Washington 98660.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a consultant in the field of public utility regulation and I am a member of Regulatory & Cogeneration Services, Inc. ("RCS").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have a Bachelor of Science Degree in Electrical Engineering from the University of Kansas and a Master of Science Degree in Engineering Management from the University of Missouri.

From June of 1972 until June of 1980, I was employed by Union Electric Company in the Transmission and Distribution, Rates, and Corporate Planning functions. In the Transmission and Distribution function, I had various areas of responsibility, including load management, budget proposals and special studies. While in the Rates function, I worked on rate design studies, filings and exhibits for several regulatory jurisdictions. In Corporate Planning, I was responsible for the development and maintenance of computer models used to simulate the Company's financial and economic operations.

In June of 1980, I joined the national consulting firm of Drazen-Brubaker & Associates, Inc. Since that time, I have participated in the analysis of various utilities for power cost forecasts, avoided cost pricing, contract negotiations for gas and electric services, siting and licensing proceedings, and rate case purposes including revenue requirement determination, class cost-of-service and rate design.

In April 1988, I formed RCS. RCS provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers. We also assist in the negotiation of contracts for utility services for large users. In general, we are engaged in regulatory consulting, rate work, feasibility, economic and cost-of-service studies, design of rates for utility service and contract negotiations.

Q. IN WHICH JURISDICTIONS HAVE YOU TESTIFIED AS AN EXPERT WITNESS REGARDING UTILITY COST AND RATE MATTERS?

A. I have testified as an expert witness in rate proceedings before commissions in the states of Alaska, Arizona, California, Delaware, Idaho, Illinois, Montana, Nevada, North Carolina, Ohio, Oregon, Washington, Wisconsin and Wyoming. In addition, I have presented testimony before the Bonneville Power Administration, the National Energy Board of Canada, the Federal Energy Regulatory Commission, publicly-owned utility boards and in court proceedings in the states of Washington, Oregon and California.

UM 1129

EXHIBIT ICNU/102

INSTALLED QF AND COGENERATION CAPACITY

DONALD W. SCHOENBECK

Installed QF and Cogeneration Capacity By State and By Percentage of Total Installed Capacity

state	QF	rank	total	% QF	rank	state	cogen	rank	total	% cogen	rank
ME	830	13	4,272	19.4%	1	MN	2,881	5	11,804	24.4%	1
HI	418	24	2,502	16.7%	2	HI	583	27	2,502	23.3%	2
TX	13,595	1	96,505	14.1%	3	MA	2,596	7	11,754	22.1%	3
LA	3,529	3	28,654	12.3%	4	LA	5,780	3	28,654	20.2%	4
CA	6,061	2	56,797	10.7%	5	ME	726	21	4,272	17.0%	5
NY	3,413	4	35,572	9.6%	6	TX	14,612	1	96,505	15.1%	6
MA	1,073	10	11,754	9.1%	7	NY	4,853	4	35,572	13.6%	7
NJ	1,517	7	17,484	8.7%	8	NJ	2,373	9	17,484	13.6%	8
MI	2,462	6	30,463	8.1%	9	DE	232	34	1,711	13.6%	9
VA	1,291	8	19,299	6.7%	10	CA	6,735	2	56,797	11.9%	10
CO	598	15	9,756	6.1%	11	MI	2,809	6	30,463	9.2%	11
CT	409	25	7,271	5.6%	12	TN	1,840	12	22,238	8.3%	12
NV	381	26	7,069	5.4%	13	WI	1,072	15	14,012	7.6%	13
FL	2,658	5	52,115	5.1%	14	CO	744	20	9,756	7.6%	14
MD	588	16	12,638	4.7%	15	AL	2,014	10	27,293	7.4%	15
AR	513	19	11,905	4.3%	16	IN	1,991	11	27,351	7.3%	16
MN	490	20	11,804	4.2%	17	IA	651	24	9,649	6.7%	17
ID	131	32	3,193	4.1%	18	**OR**	**717**	**22**	**12,142**	**5.9%**	**18**
DE	65	36	1,711	3.8%	19	VA	1,113	14	19,299	5.8%	19
NC	1,028	11	27,460	3.7%	20	AK	116	37	2,196	5.3%	20
AL	970	12	27,293	3.6%	21	MD	642	25	12,638	5.1%	21
RI	69	35	1,969	3.5%	22	NV	344	32	7,069	4.9%	22
WI	423	23	14,012	3.0%	23	CT	341	33	7,271	4.7%	23
OK	526	18	17,473	3.0%	24	FL	2,396	8	52,115	4.6%	24
MS	357	27	13,572	2.6%	25	AZ	850	19	21,481	4.0%	25
PA	1,076	9	41,676	2.6%	26	OK	691	23	17,473	4.0%	26
GA	825	14	35,524	2.3%	27	AR	470	30	11,905	3.9%	27
SC	427	22	20,769	2.1%	28	RI	78	40	1,969	3.9%	28
IA	171	30	9,649	1.8%	29	MS	509	29	13,572	3.7%	29
WV	288	28	16,939	1.7%	30	NC	997	16	27,460	3.6%	30
WA	441	21	26,632	1.7%	31	PA	1,437	13	41,676	3.4%	31
IL	560	17	43,396	1.3%	32	WA	887	18	26,632	3.3%	32
TN	278	29	22,238	1.2%	33	GA	972	17	35,524	2.7%	33
OR	**91**	**33**	**12,142**	**0.7%**	**34**	SC	361	31	20,769	1.7%	34
OH	166	31	32,743	0.5%	35	OH	557	28	32,743	1.7%	35
AK	8	42	2,196	0.4%	36	ID	51	42	3,193	1.6%	36
MO	78	34	21,540	0.4%	37	IL	633	26	43,396	1.5%	37
KS	33	38	10,910	0.3%	38	NM	82	39	6,410	1.3%	38
AZ	63	37	21,481	0.3%	39	NH	38	44	3,598	1.1%	39
NM	17	40	6,410	0.3%	40	UT	58	41	6,169	0.9%	40
NE	8	43	6,267	0.1%	41	WY	47	43	6,686	0.7%	41
KY	27	39	21,956	0.1%	42	WV	108	38	16,939	0.6%	42
NH	3	44	3,598	0.1%	43	MO	120	35	21,540	0.6%	43
IN	9	41	27,351	0.0%	44	ND	27	45	4,854	0.6%	44
UT	2	45	6,169	0.0%	45	KY	119	36	21,956	0.5%	45
VT	0	46	1,079	0.0%	46	VT	4	47	1,079	0.4%	46
SD	0	47	3,019	0.0%	47	NE	13	46	6,267	0.2%	47
ND	0	48	4,854	0.0%	48	KS	1	48	10,910	0.0%	48
MT	0	49	5,141	0.0%	49	SD	0	49	3,019	0.0%	49
WY	0	50	6,686	0.0%	50	MT	0	50	5,141	0.0%	50
U.S.	47,969		932,908	5.1%		U.S.	67,267		932,908	7.2%	

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Direct Testimony of Donald W. Schoenbeck on behalf of the Industrial Customers of Northwest Utilities upon the parties, shown below, on the official service list for Docket No. UM 1129, by causing the document to be deposited, postage-prepaid, in the U.S. Mail.

DATED at Portland, Oregon, this 3rd day of August, 2004.

DAVISON VAN CLEVE, P.C.
Ruth A. Miller

JAMES BARRETT
ATER WYNNE LLP
222 SW COLUMBIA STE 1800
PORTLAND OR 97201
jmb@aterwynne.com

JUSTIN BOOSE
STOEL RIVES
900 SW FIFTH AVENUE, SUITE 2600
PORTLAND OR 97204
jrboose@stoel.com

JACK BREEN
PUBLIC UTILITY COMMISSION
PO BOX 2148
SALEM OR 97308-2148
jack.breen@state.or.us

BRIAN COLE
SYMBIOTICS, LLC
PO BOX 1088
BAKER CITY OR 97814
bc@orbisgroup.org

BRUCE CRAIG
ASCENTERGY CORP
440 BENMAR DR STE 2230
HOUSTON TX 77060
bcraig@asc-co.com

CHRIS CROWLEY
COLUMBIA ENERGY PARTNERS
PO BOX 1000
LA CENTER WA 98629
ccrowley@columbiaep.com

CAREL DE WINKEL
OREGON DEPARTMENT OF ENERGY
625 MARION STREET NE
SALEM OR 97301
carel.dewinkel@state.or.us

CRAIG DEHART
MIDDLEFORK IRRIGATION DISTRICT
PO BOX 291
PARKDALE OR 97041
mfidcraig@gorge.net

J RICHARD GEORGE
PORTLAND GENERAL ELECTRIC COMPANY
121 SW SALMON ST
PORTLAND OR 97204
richard_george@pgn.com

THOMAS M GRIM
CABLE HUSTON BENEDICT ET AL
1001 SW FIFTH AVE STE 2000
PORTLAND OR 97204-1136
tgrim@chbh.com

DAVID HAWK
J R SIMPLOT COMPANY
PO BOX 27
BOISE ID 83707
david.hawk@simplot.com

STEVEN C JOHNSON
CENTRAL OREGON IRRIGATION DISTRICT
2598 NORTH HIGHWAY 97
REDMOND OR 97756
stevej@coid.org